State of California

Environmental Protection Agency

AIR RESOURCES BOARD

AMENDMENTS TO THE CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS

FINAL STATEMENT OF REASONS

May 2014

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State of California
California Environmental Protection Agency
AIR RESOURCES BOARD

**Final Statement of Reasons for Rulemaking,
Including Summary of Public Comments and Agency Responses**

PUBLIC HEARING TO CONSIDER PROPOSED AMENDMENTS TO THE CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS

Public Hearing Date: April 25, 2014
Agenda Item No.: 14-3-3

I. GENERAL

A. Action Taken in This Rulemaking

In this rulemaking, the Air Resources Board (ARB or the Board) is adopting amendments to the California Cap-and-Trade Regulation (Regulation) to provide additional details to clarify implementation of the Regulation, address stakeholder concerns on cost containment, extend the transition assistance for covered entities in the program, present a new offset protocol, and enhance ARB 's ability to oversee and implement the Regulation. The amendments were developed pursuant to the requirements of the California Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (AB 32). The amendments are codified at Subarticle 12, Subchapter 10 Climate Change, Article 5, sections 95802, 95811, 95812, 95813, 95814, 95830, 95831, 95832, 95833, 95834, 95841.1, 95851, 95852, 95852.1.1, 95852.2, , 95853, 95856, 95857, 95870, 95890, 95891, 95892, 95893, 95910, 95911, 95912, 95913, 95914, 95920, 95921, 95922, 95942, 95970, 95971, 95972, 95973, 95974, 95975, 95976, 95977, 95977.1, 95978, 95979, 95980, 95980.1,95981, 95981.1, 95982, 95983, 95984, 95985, 95986, 95987, 95990, 95991, and 96022, title 17, California Code of Regulations, and newly adopted sections 95894, 95895, 95923, 95979.1, new Appendix B, and new Appendix C, title 17, California Code of Regulations. The regulation also incorporated the California Air Resources Board Compliance Offset Protocol Mine Methane Capture Projects: Capturing and Destroying Methane From U.S. Coal and Trona Mines (2013).

The amendments to the Regulation were initiated with the publication a notice in the California Notice Register on September 6, 2013 and notice of public hearing scheduled for October 25, 2013.[1] A Staff Report: Initial Statement of Reasons, entitled "Proposed

1 California Air Resources Board. Notice of Public Hearing to Consider Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Posted September 6, 2013. Available online at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" (Staff Report or ISOR), the full text of the proposed regulatory amendments, and other supporting documentation were made available for public review and comment starting on September 9, 2013, running for 45 days through to October 24, 2013. The regulatory amendments as proposed would:

- Provide allowance allocation for additional sectors and modify allocation for existing sectors based on new information;
- Implement additional cost containment mechanisms;
- Define new covered entities and exempt sectors where direct regulation best meets the goals of AB32;
- Exempt certain covered entities' emissions from incurring a compliance obligation under the program for the first compliance period;
- Provide additional clarity on the prohibition against resource shuffling in the electricity sector;
- Provide for better coordination of the Regulation with other State renewable electricity requirements;
- Include a new offset protocol and clarify and add processes for implementation of the compliance offset program;
- Provide modifications to market rules for auctions and transfers in the tracking system; and
- Include additional provisions to enhance market security such as requiring submission of information on voluntarily associated entities that may have a relationship with covered or opt-in entities.

At its October 25, 2013 public hearing, the Board approved Resolution 13-44[2] directing the Executive Officer to consider the topics in Attachment A and make additional 15-day changes as appropriate to the Cap-and-Trade Regulation as part of a subsequent 15-day notice to the rulemaking package. The Resolution also directed the Executive Officer to make available for public review an analysis of the potential impact of Cap-and-Trade offsets on coal mine economics and to complete the environmental review process by preparing written responses to comments received on the environmental analysis to present to the Board at a subsequent hearing for approval, as required by ARB's California Environmental Quality Act (CEQA) certified regulatory program (California Code of Regulations, title 17, section 60007(a)).

During the 45-day and the subsequent 15-day public comment periods, the public submitted comments on the proposed amendments.[3] The 45-day comment period commenced on September 9, 2013, and ended on October 24, 2013, with additional oral and written comments submitted at the October 25, 2013 Board hearing. Staff held a Cap-and-Trade Refineries and Related Industries Workshop on October 7, 2013. Since this workshop occurred within the 45-day comment period, oral comments heard

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2 California Air Resources Board. Board Resolution 13-44. Posted November 8, 2013. Available online at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

3 All public comments received on the proposed amendments can be found online at: http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade13

at this workshop are also included in the formal rulemaking record for the regulatory amendments. The 15-day comment period occurred from March 21, 2014 to April 5, 2014.

At a public hearing held on April 25, 2014, the Board approved Resolution 14-4, approving the written responses to environmental comments, making required CEQA and other findings, and adopting the final regulatory amendments, including the Mine Methane Capture Compliance Offset Protocol. The Resolution also directed the Executive Officer to finalize the Final Statement of Reasons (FSOR) for the regulatory amendments and to submit the final rulemaking package to the Office of Administrative Law for review. The FSOR provides written responses to all comments received on the proposed amendments during the 45-day and 15-day comment periods, at the October 7, 2013 refinery workshop, during the October 25, 2013 Board hearing, and during the final April 25, 2014 Board hearing.

B. Mandates and Fiscal Impacts to Local Governments and School Districts

The Board has determined that the proposed regulatory action would not create costs or savings, as defined in Government Code sections 11346.5(a)(5) and 11346.5(a)(6), to State agencies or in federal funding to the State. The proposed regulatory action would not create costs and would not impose a mandate on State and local agencies, or school districts. Eight California public universities, the California Department of Water Resources, several municipal utilities, and one county correctional facility would have a compliance obligation under the proposed regulation. These entities would be required to surrender allowances or offsets equal to the amount of their GHG emissions during the compliance period as was already required under the current regulation.
Because the regulatory requirements apply equally to all covered entities and unique requirements are not imposed on local agencies, the Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies or school districts that is required to be reimbursed pursuant to section 6 of article XIII B of the California Constitution.

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses. Staff anticipated that regulated business would need to register for accounts, report transactions and disclose corporate affiliates, among other actions. The proposed Regulation specifies exactly what information will be required. Complying with these requirements does not add any additional costs over what was assumed in the Cap-and-Trade Regulation. The proposed amendments provide more specificity and clarification regarding the information required for registration with ARB in the compliance instrument tracking system and for the reporting of transactions in the compliance instrument tracking system. The collection of this information does not add cost to covered entities over what has been previously estimated for the existing Regulation. Additionally the amendments provide clarity with respect to resource shuffling and cooperation with renewable electricity. There are no requirements placed on non-covered businesses or private individuals.

The proposed amendments specify the mechanism for allocation of allowances to several sectors that are currently covered by the cap-and-trade program who previously did not receive an allocation and those sectors that will be covered in 2015. These sectors include natural gas distribution facilities, California public universities, the Department of Water Resources, the Metropolitan Water District, and electricity generators who have contracts that cannot be renegotiated to include a CO_2 cost. Further, these amendments extend the 100 percent assistance factor for all industrial covered entities receiving allowances through the second compliance period. Additional allocation of allowances will reduce the near-term compliance cost for covered facilities receiving allowances.

The Executive Officer has determined that representative private persons and businesses would not be affected by the proposed regulatory action. Pursuant to Government Code section 11346.5(a)(7)(C), the Executive Officer has made an initial determination that the proposed regulatory action would not have a significant State-wide adverse economic impact directly affecting businesses, and little or no impact on the ability of California businesses to compete with businesses in other states. The proposed Regulation would not impose sufficient direct or indirect costs to eliminate businesses in California. A detailed description of the economic impacts associated with the proposed amendments is included in Chapter IV of the Staff Report.

C. Consideration of Alternatives to the Proposed Amendments

Staff is required to consider alternatives to the proposed amendments for the Cap-and-Trade Regulation. As discussed in Chapter V of the Staff Report, staff analyzed the following alternatives to the proposed amendments to the Cap-and-Trade Regulation:

- Do not amend the Cap-and-Trade Regulation (No Project Alternative);
- Consider alternative allocation scenarios (Allocation Alternative);
- Consider alternative cost containment mechanisms (Cost Containment Alternative).

For the reasons set forth in the Staff Report, in staff's comments and responses to comments at the Board hearings, and in this FSOR, the Board determined that no alternative considered by the agency would be more effective in carrying out the goals of AB 32, or would be as effective as and less burdensome to affected private persons, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provisions of law than the action taken by the Board. Further, none of the options that would have enabled California to meet AB 32 goals were as cost effective as the proposed Regulation and substantially address the public problem stated in the notice. Staff provides a discussion of each alternative in Chapter V of the Staff Report for the proposed amendments.

II. MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL

A. Modifications Approved at the Board Hearing and Provided for in the 15-Day Comment Period

Pursuant to the Board direction provided in Resolution 13-44, ARB released a Notice of Public Availability of Modified Text and Availability of Additional Documents and Information (15-Day Notice) on March 21, 2014, which placed additional documents into the regulatory record and presented the additional modifications to the regulatory text after extensive consultation with stakeholders, including modifications to the proposed Compliance Offset Protocol Mine Methane Capture Projects (MMC protocol).[4] In the interest of completeness, staff also added the following two documents to the rulemaking record as part of the 15-day formal comment period:

- The Mine Methane Capture Protocol and Mining Economics
- Appendix A Product-Based Benchmark Development

B. Non-Substantive Corrections to the Regulation

After the close of the 15-day comment period, the Executive Officer determined that no additional modifications should be made to the regulations, with the exception of the non-substantive changes listed below.

1. <u>Correction of typographical error</u>: In section 95894(a), the term "and by" was changed to "of." The sentence, which previously read "shall submit the following in writing via certified mail to the Executive Officer by September 2 and by each year as applicable" did not make sense.
2. <u>Format change</u>: In section 95894(d), the line format was changed to left justified to conform to the formatting of the rest of the Regulation.
3. <u>Correction of typographical error</u>: Section 95910(d)(4)(C) refers to two sections (95892(c) and 95893(c)), but lists them as "section 95892(c) and 95893(c)." This has been corrected to read as follows: "… sections 95892(c) and 95893(c)."
4. <u>Correction of typographical error</u>: Section 95912(d)(4)(C) was missing the article "a" in front of the phrase "… change in the existing allocation…" This has been corrected to include the "a."
5. <u>Correction of citation</u>: Section 95914(d)(2) incorrectly cites to section 95830 when referring to the allocation of purchase limit shares. This allocation is actually contained in section 95833. Section 95914(d) has been modified to refer to the correct citation.
6. <u>Correction of hierarchal error and citations</u>: Section 95986: Corrected hierarchy in this due to deletion of provision (c) in the 45-day package. As a result of correcting the hierarchy, staff made changes to the references throughout section 95986.

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[4] California Air Resources Board. Notice of Public Availability of Modified Text and Availability of Additional Documents and Information. Posted March 21, 2014. Available online at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

7. Correction of citation: In section 95990(a): Due to hierarchy changes in section 95986, staff corrected a reference in this section.
8. Correction of typographical error: In section 95990(l)(1)(A) staff deleted the word “and” from the original text to correct the sentence structure.
9. Remove date placeholder: Staff replaced the placeholders throughout the Regulation with the date of the adoption of the Mine Methane Capture Protocol, which is April 25, 2014.

The above described modifications constitute non-substantial changes to the regulatory text because they more accurately reflect the numbering of sections, correct spelling and grammatical errors, and correct citations, but do not materially alter the requirements, rights, responsibilities, conditions, or prescriptions contained in the regulation.

III. DOCUMENTS INCORPORATED BY REFERENCE

The Cap-and-Trade Regulation and the Compliance Offset Protocol Mine Methane Capture Projects adopted by the Executive Officer incorporate by reference the following documents:

1. Association of Official Analytical Chemists (1980). Official Methods of Analysis: 13th Edition. Sections 32.025 to 32.030, Method III (Potentiometric Method). (section 95802, title 17, California Code of Regulations)
2. Association of Official Analytical Chemists (1980). Official Methods of Analysis: 13th Edition. Sections 32.014 to 32.016 and Section 52.012. (section 95802, title 17, California Code of Regulations)
3. California Energy Commission. Guidelines for California’s Solar Electric Incentive Programs Pursuant To Senate Bill 1. First Edition. December 2007. CEC-300-2007-012-CMF.
4. California Energy Commission. Guidelines for California’s Solar Electric Incentive Programs (Senate Bill 1). Second Edition. December 2008. CEC-300-2008-007-CMF.
5. California Energy Commission. Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1). Third Edition. June 2010. CEC-300-2010-004-CMF.
6. California Energy Commission. Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1). Fourth Edition. July 2011. CEC-300-2011-005-CMF.
7. California Energy Commission. Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1). Fifth Edition. January 2013. CEC-300-2012-008-ED5-CMF.

These documents were incorporated by reference because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in the California Code of Regulations. In addition, some of the documents are copyrighted, and cannot be reprinted or distributed without violating the licensing agreements. The documents are lengthy and highly technical test methods and engineering documents that would add unnecessary additional volume to the regulation. Distribution to all recipients of the

California Code of Regulations is not needed because the interested audience for these documents is limited to the technical staff at a portion of reporting facilities, most of whom are already familiar with these methods and documents. Also, the incorporated documents were made available by ARB upon request during the rulemaking action and will continue to be available in the future. The documents are also available from colleges and public libraries, or may be purchased directly from the publishers.

IV. SUMMARY OF COMMENTS MADE DURING THE 45-DAY COMMENT PERIOD AND AGENCY RESPONSES

Chapter IV of this FSOR contains all comments submitted during the 45-day comment period and the October 25, 2013 Board hearing that were directed at the proposed amendments or to the procedures followed by ARB in proposing the amendments, together with ARB's responses. The 45-day comment period commenced on September 9, 2013, and ended on October 24, 2013, with additional comments submitted at the October 25, 2015 Board hearing on the proposed amendments. As the October 7, 2013 Cap-and-Trade Refineries and Related Industries Workshop was also held within the 45-day comment period, oral comments heard and written comments received at this workshop are also addressed in Chapter IV of this FSOR. Comments from the October 7, 2013 workshop and comments submitted informally shortly thereafter were not submitted in accordance with the procedure provided in either the 45-day or 15-day public comment notices. Therefore, ARB staff does not believe a response is required but provides responses herein in the interest of completeness.

ARB received 112 letters on the proposed amendments during the 45-day comment period, including the October 2013 Board hearing. In addition, 11 commenters provided written comments related to the October 7, 2013 refinery workshop, 15 commenters gave oral testimony at the October 7, 2013 refinery workshop, and 60 commenters gave oral testimony during the October 2013 Board hearing. Commenters included representatives from the electricity and natural gas sectors, environmental non-governmental organizations, oil and natural gas extraction and refining sectors, offset project developers and offset registries, and representatives from trade groups and academic organizations. To facilitate use of this document, comments are categorized into one of 14 sections below, and are grouped for response wherever possible.

Table IV-1 below lists commenters that submitted oral and written comments on the proposed amendments during the 45-day comment period and at the October 2013 Board Hearing, identifies the date and form of their comments, and shows the abbreviation assigned to each.

A. LIST OF COMMENTERS

Abbreviation	Commenter
AB32IG	Shelly Sullivan, AB 32 Implementation Group Written Testimony: 10/23/2013
ACC	Emily Rooney, Agricultural Council of California Oral Testimony: 10/25/2013
AEPCO	Kyle Danish, Van Ness Feldman, LLP (for AEPCO) Written Testimony: 10/22/2013
ALA	Will Barrett, American Lung Association Oral Testimony: 10/25/2013
ALSTON	Elise Paeffgen, Alston & Bird Oral Testimony: 10/25/2013
APC 1	Keith Adams, Air Products and Chemicals, Inc. Written Testimony: 10/14/2013
APC 2	Keith Adams, Air Products and Chemicals, Inc. Oral Testimony: 10/7/2013
APEN 1	Mari Rose Taruc, Asian Pacific Environmental Network Written Testimony: 10/24/2013
APS	Justin Thompson, Arizona Public Service Written Testimony: 10/21/2013
AZUSA	George Morrow, Azusa Light and Water Oral Testimony: 10/25/2013
BEM 1	Margaret Miller, Brookfield Energy Marketing Written Testimony: 10/15/2013
BIOTHERMICA 1	Raphael Bruneau, Biothermica Technologies Inc. Written Testimony: 10/18/2013
BLUESOURCE 1	Eric Townsend, Blue Source LLC Written Testimony: 10/23/2013
BP 1	Ralph Moran, BP America Inc. Written Testimony: 10/22/2013
CACOGEN	Beth Vaughan, California Cogeneration Council Oral Testimony: 10/25/2013
CALPINE 1	Kassandra Gough, Calpine Corporation Written Testimony: 10/23/2013
CALPINE 2	Kassandra Gough, Calpine Corporation Oral Testimony: 10/25/2013
CAR 1	Gary Gero, Climate Action Reserve Written Testimony: 10/23/2013
CAR 2	Gary Gero, Climate Action Reserve Oral Testimony: 10/25/2013

Abbreviation	Commenter
CARDINAL 1	Ron Dahlin, Cardinal Cogeneration Inc. Written Testimony: 10/22/2013
CARDINAL 2	Bill Buchan, Cardinal Cogeneration Oral Testimony: 10/25/2013
CCA	Bill Magavern, Coalition for Clean Air Oral Testimony: 10/25/2013
CCCSD 1	Curtis Swanson, Central Contra Costa Sanitary District Written Testimony: 9/30/2013
CCDGCC	Ann Trowbridge, California Clean DG Coalition Written Testimony: 10/18/2013
CCEEB 1	Robert Lucas, Council for Environmental and Economic Balance Written Testimony: 10/23/2013
CE2CAPITAL 1	Greg Arnold, CE2 Carbon Capital Written Testimony: 10/15/2013
CE2CAPITAL 2	Greg Arnold, CE2 Carbon Capital Oral Testimony: 10/25/2013
CE2CAPITAL 3	Tony Brunello, C2E Carbon Capital Oral Testimony: 10/25/2013
CEERT	John White, Center for Energy Efficiency and Renewable Technology Oral Testimony: 10/25/2013
CFEA 1	Jon Costantino, Coalition for Fair and Equitable Allocation Written Testimony: 10/14/2013
CFEA 2	Jon Costantino, Coalition for Fair and Equitable Allocation; Catherine Reheis-Boyd, WSPA Written Testimony: 9/26/2013
CFEA 3	Jon Costantino, Coalition for Fair and Equitable Allocation Written Testimony: 10/22/2013
CFEA 4	John Costantino, Coalition for Fair and Equitable Allocation Oral Testimony: 10/25/2013
CFEA 5	Jon Costantino, Coalition for Fair and Equitable Allocation Oral Testimony: 10/7/2013
CHEVRON 1	Lloyd Avram, Chevron Corporation Written Testimony: 10/16/2013
CHEVRON 2	Lloyd Avram, Chevron Corporation Written Testimony: 10/16/2013
CHEVRON 3	Julia Bussey, Chevron Corporation Oral Testimony: 10/25/2013
CHEVRON 4	Julia Bussey, Chevron Corporation Oral Testimony: 10/7/2013
CHEVRON 5	Susann Nordrum, Chevron Corporation Oral Testimony: 10/7/2013

Abbreviation	Commenter
CLFP 1	John Larrea, California League of Food Processors Written Testimony: 10/19/2013
CLFP 2	John Larrea, California League of Food Processors Oral Testimony: 10/25/2013
CMTA 1	Dorothy Rothrock, California Manufacturers and Technology Association Oral Testimony: 10/25/2013
COVANTA 1	Ellie Booth, Covanta Energy Written Testimony: 10/21/2013
CPM 1	Carl Fink, Capital Power Marketing Inc. Written Testimony: 10/22/2013
CROCKETT	Dan Consie, Crockett Cogeneration Oral Testimony: 10/25/2013
CRS 1	Todd Jones, Center for Resource Solutions Written Testimony: 10/23/2013
CSPA 1	Peter Weiner, Paul Hastings LLP (on behalf of Concentrating Solar Power Alliance) Written Testimony: 10/18/2013
CSPA 2	Peter Weiner, Paul Hastings LLP Oral Testimony: 10/25/2013
CSU 1	Leonard Pettis, California State University Written Testimony: 10/16/2013
CSU 2	Leonard Pettis, California State University Oral Testimony: 10/25/2013
CULLENWARD 1	Danny Cullenward, Private Individual Written Testimony: 10/23/2013
CULLENWARD 2	Danny Cullenward, Private Individual Oral Testimony: 10/25/2013
CWCCG	Sarah Deslauriers, California Wastewater Climate Change Group Written Testimony: 10/17/2013
DWR	Mark Cowin, Department of Water Resources Written Testimony: 10/23/2013
EDF 1	Erica Morehouse, Environmental Defense Fund Written Testimony: 10/14/2013
EDF 2	Derrik Walker, Environmental Defense Fund Oral Testimony: 10/25/2013
ELEMENT	Jackie Ferlita, Element Markets Written Testimony: 10/22/2013
EXXON	Derek Wheeler, Exxon Mobile Corporation Oral Testimony: 10/7/2013

Abbreviation	Commenter
FWW	Elizabeth Nussbaumer, Food & Water Watch Written Testimony: 9/26/2013
GAIA	Monica Wilson, Global Alliance for Incinerator Alternatives Written Testimony: 10/24/2013
GALLO	John Nagle, E&J Gallo Winery Written Testimony: 10/16/2013
GI	Ryan Young, The Greenlining Institute Written Testimony: 10/15/2013
GPI	Andrew Johnson, Graphic Packaging International, Inc. Written Testimony: 9/25/2013
GREEN 1	Jerry Gureghiam, Green Holdings Oral Testimony: 10/25/2013
GUG	Debbie Lloyd, Gas Utility Group Oral Testimony: 10/25/2013
HCE 1	Diana Golis, Holy Cross Energy Written Testimony: 10/22/2013
IEPA 1	Amber Riesenhuber, Independent Energy Producers Association Written Testimony: 10/22/2013
IEPA 2	Amber Riesenhuber, Independent Energy Producers Association Oral Testimony: 10/25/2013
IETA 1	Dirk Forrister, International Emissions Trading Association Written Testimony: 10/23/2013
INERGY	Ann Trowbridge, Day Carter & Murphy LLP (for Inergy West Coast LLC) Written Testimony: 10/23/2013
JUC	Claire Halbrook, Joint Utilites Commission Written Testimony: 10/23/2013
KBONE	Ken Bone, Private Individual Written Testimony: 10/22/2013
KC 1	Dell Majure, Kimberley-Clark Written Testimony: 9/12/2013
KERN 1	Jennifer Haley, Kern Oil & Refining Company Written Testimony: 10/14/2013
KERN 2	Melinda Hicks, Kern Oil & Refining Co. Written Testimony: 10/23/2013
KERN 3	Melinda Hicks, Kern Oil and Refining Company Oral Testimony: 10/25/2013
KERN 4	Jennifer Haley, Kern Oil & Refining Company Oral Testimony: 10/7/2013
KERN 5	Melinda Hicks, Kern Oil & Refining Company Oral Testimony: 10/7/2013

Abbreviation	Commenter
LACOUNTY	Jackson F. Stoddard, Manatt Phelps & Phillips LLC (for Los Angeles County) Written Testimony: 10/24/2013
LACSD 1	Frank Caponi, Los Angeles County Sanitation District Written Testimony: 10/22/2013
LACSD 2	Frank Caponi, Los Angeles County Sanitation District Oral Testimony: 10/25/2013
LADWP 1	Jodean Giese, Los Angeles Department of Water and Power Written Testimony: 10/21/2013
LADWP 2	Cindy Parsons, Los Angeles Department of Water and Power Oral Testimony: 10/25/2013
LBC	Bob Foster, Mayor, City of Long Beach Written Testimony: 10/23/2013
LEE	Johnny Lee, Private Individual Oral Testimony: 10/25/2013
LLH	Maureen Gorsen, Loma Linda Hospital Oral Testimony: 10/25/2013
LTC 1	Grant Aguinaldo, Lunday-Thagard Company Written Testimony: 10/14/2013
LTC 2	Grant Aguinaldo, Lunday-Thagard Co. Oral Testimony: 10/25/2013
MANVILLE	Bruce Ray, Johns Manville Oral Testimony: 10/25/2013
MARDEN	Eden Marden, California Farmer Written Testimony: 9/23/2013
MS	Steve Huhman, Morgan Stanley Written Testimony: 9/9/2013
MSR 1	Martin Hopper, M-S-R Public Power Agency Written Testimony: 10/23/2013
MWD 1	Jeffrey Kightliner, Metropolitan Water District Written Testimony: 10/22/2013
MWD 2	Mark Parsons, Metropolitan Water District Oral Testimony: 10/25/2013
NAIMA 1	Angus Crane, North American Insulation Manufacturers Association Written Testimony: 10/23/2013
NAIMA 2	Angus Crane, North American Insulation Manufacturers Association Oral Testimony: 10/25/2013
NCPA 1	Susie Berlin, Law Offices of Susie Berlin (for Northern California Power Agency) Written Testimony: 10/23/2013

Abbreviation	Commenter
NCPA 2	Susie Berlin, Northern California Power Agency and MSR Power Angecy Oral Testimony: 10/25/2013
NOBLE 1	Thomas Corr, Noble Americas Energy Solutions LLC Written Testimony: 10/18/2013
NRDC 1	Alex Jackson, Natural Resource Defense Council; David Foster, BlueGreen Alliance; Robert LaVenture, United Steelworkers Written Testimony: 10/14/2013
NRDC 2	Alex Jackson, Natural Resource Defense Council Written Testimony: 10/16/2013
NRDC 3	Alex Jackson, Natural Resource Defense Council Written Testimony: 10/25/2013
NRDC 4	Alex Jackson, Natural Resource Defense Council Oral Testimony: 10/25/2013
OLAM	Narinder Singh, Olam Spices and Vegetables, Inc. Written Testimony: 9/10/2013
OLS 1	Jerry Bloom, Winston & Strawn LLP (for OLS Energy Chino LLC) Written Testimony: 9/25/2013
OLS 2	Jerry Bloom, OLS Energy Chino LLC Oral Testimony: 10/25/2013
PACIFICORP 1	Mary Wiencke, PacifiCorp Written Testimony: 10/15/2013
PANOCHE 1	David Huard, Manatt Phelps & Phillips LLC (for Panoche Energy Center LLC) Written Testimony: 10/23/2013
PARAMOUNT 1	Gary Grimes, Paramount Petroleum Written Testimony: 10/25/2013
PARAMOUNT 2	Gary Grimes, Paramount Petroleum Oral Testimony: 10/25/2013
PARAMOUNT 3	Gary Grimes, Paramount Petroleum Oral Testimony: 10/7/2013
PG 1	Kara Roeder, The Procter & Gamble Paper Products Company Written Testimony: 10/18/2013
PGE 1	Mark Krausse, Pacific Gas & Electric (on behalf of Joint Utility Group) Written Testimony: 10/18/2013
PGE 2	Mark Krausse, Pacific Gas & Electric Written Testimony: 10/18/2013
PGE 3	Mark Krausse, Pacific Gas and Electric Oral Testimony: 10/25/2013
PGEC	Elysia Treanor,Portland General Electric Company Written Testimony: 10/22/2013

Abbreviation	Commenter
PH 1	Peter Weiner, Paul Hastings LLP Written Testimony: 10/14/2013
PH 2	Peter Weiner, Paul Hastings LLP Written Testimony: 10/21/2013
PHILLIPS 1	Stephanie Williams, Phillips 66 Written Testimony: 10/25/2013
PHILLIPS 2	Stephanie Williams, Phillips 66 Oral Testimony: 10/25/2013
PHILLIPS 3	Steve Smith, Phillips 66 Oral Testimony: 10/7/2013
PHILLIPS 4	Chris Chandler, Phillips 66 Oral Testimony: 10/7/2013
PHILLIPS 5	Stephanie Williams, Phillips 66 Oral Testimony: 10/7/2013
POWEREX 1	Nicholas van Aelstyn, Beveridge & Diamond (for Powerex Corporation) Written Testimony: 10/23/2013
PRAXAIR 1	Gerard Miller, Praxair Inc. Written Testimony: 10/23/2013
PRAXAIR 2	Brian Bearing, Praxair Inc. Oral Testimony: 10/7/2013
QUALCOMM 1	Gail Welch, Qualcomm Incorporated Written Testimony: 10/17/2013
QUALCOMM 2	Glail Welch, Qualcomm Oral Testimony: 10/25/2013
RAPC 1	Keith Adams, Air Products and Chemicals, Inc. Written Testimony: 10/6/2013
RAPC 2	Keith Adams, Air Products and Chemicals, Inc. Written Testimony: 10/7/2013
RAPC 3	Keith Adams, Air Products and Chemicals, Inc. Written Testimony 10/13/2013
RAPC 4	Keith Adams, Air Products and Chemicals, Inc. Written Testimony: 10/16/2013
RCE 1	Michael Cote, Ruby Canyon Engineering Written Testimony: 10/23/2013
RCE 2	Michael Cote, Ruby Canyon Engineering Oral Testimony: 10/25/2013
RCFEA 1	Jon Costantino, Manatt, Phelps & Phillips LLC (for Coalition for Fair and Equitable Allocation) Written Testimony: 9/18/2013

Abbreviation	Commenter
RCFEA 2	Jon Costantino, Coalition for Fair and Equitable Allocation, and Catherine Reheis-Boyd, Western States Petroleum Association Written Testimony: 9/26/2013
REMA	Joseph Seymour, Renewable Energy Markets Association Written Testimony: 10/23/2013
RLIQUIDE 1	Cassie Gilson, Gilson Government Strategies (for Air Liquide) Written Testimony: 10/10/2013
RLIQUIDE 2	Dwayne Phillips, Air Liquide Written Testimony: 10/14/2013
ROSENTHAL	Richard Rosenthal, Private Individual Written Testimony: 10/23/2013
RPGE	Mark Krausse, Pacific Gas & Electric Co. Written Testimony: 9/12/2013
SCE 1	Nancy Allred, Southern California Edison Company Written Testimony: 10/15/2013
SCE 2	Michael Hertel, Southern California Energy Written Testimony: 10/21/2013
SCE 3	Frank Harris, Southern California Edison Oral Testimony: 10/25/2013
SCGE 1	Tanya Peacock, Southern California Gas and Electric Oral Testimony: 10/25/2013
SCPPA 1	Lily Mitchell, Southern California Public Power Authority Written Testimony: 10/18/2013
SCPPA 2	Lily Mitchell, Southern California Public Power Authority, Magnolia Written Testimony: 10/21/2013
SCPPA 3	Norman Pedersen, Southern California Public Power Authority Oral Testimony: 10/25/2013
SEMPRA 1	Katy Wilson, Sempra Generation Written Testimony: 10/17/2013
SEMPRA 2	Tamara Rasberry, Sempra Utilities Written Testimony: 10/18/2013
SHELL 1	Marcie Milner, Shell Energy North America Written Testimony: 10/17/2013
SIDEL	Sid Abma, Sidel Systems USA Inc. Written Testimony: 9/9/2013
SIERRA	Ed Moreno, Sierra Club California Oral Testimony: 10/25/2013
SKINNER	Nancy Skinner, Assemblymember, Fifteenth District Written Testimony: 10/17/2013

Abbreviation	Commenter
SMUD 1	Williams Westerfield, Sacramento Municipal Utility District Written Testimony: 10/18/2013
SMUD 2	William Westerfield, Sacramento Municipal Utility District Written Testimony: 10/23/2013
SMUD 3	Kevin Hart, Sacramento Municipal Utility District Oral Testimony: 10/7/2013
SOLAR	Craig Anderson, Solar Turbines Oral Testimony: 10/25/2013
SOLVAY 1	Ron Hughes, Solvay Written Testimony: 10/18/2013
STANFORD 1	Barbara Haya, Stanford Law School Written Testimony: 10/22/2013
STANFORD 2	Barbara Haya, Stanford Law School Written Testimony: 10/23/2013
STANFORD 3	Barbara Haya, Stanford Law School Oral Testimony: 10/25/2013
STANFORD 4	Aaron Strong, Stanford University Oral Testimony: 10/25/2013
SWC 1	Terry L. Erlewine, State Water Contractors Written Testimony: 10/23/2013
SWC 2	Tim Haines, State Water Contractors Written Testimony: 10/23/2013
SWC 3	Tim Haines, State Water Contractors Oral Testimony: 10/25/2013
TESORO 1	Daniel Riley, Tesoro Written Testimony: 10/23/2013
TESORO 2	Chuck White, Tesoro Oral Testimony: 10/7/2013
TID 1	Dan Severson, Turlock Irrigation District Written Testimony: 10/23/2013
TID 2	Brian Biering, Turlock Irrigation District Oral Testimony: 10/25/2013
TOOLE ONEIL 1	Barbara Toole Oneil, Consultant Oral Testimony: 10/25/2013
USDOD	C.L. Stathos, U.S. Department of Defense Written Testimony: 10/22/2013
USW 1	Erica Kent, United Steel Workers Oral Testimony: 10/25/2013
USW 2	Mike Smith, United Steel Workers Oral Testimony: 10/25/2013

Abbreviation	Commenter
USW 3	Lisa Bowman, United Steel Workers Oral Testimony: 10/25/2013
USW 4	David Campbell, United Steel Workers Oral Testimony: 10/25/2013
VALERO 1	Robert Ehlers, Valero Written Testimony: 10/15/2013
VALERO 2	Kirk A. Saffell, Valero Written Testimony: 10/22/2013
VCS	David Antonioli, Verified Carbon Standard Written Testimony: 10/23/2013
VESSELS 1	Thomas Vessels, Vessels Coal Gas, Inc. Written Testimony: 10/23/2013
VESSELS 2	Thomas Vessels, Vessels Coal Gas Inc. Oral Testimony: 10/25/2013
WGA	Matthew Allen, Western Growers Association Written Testimony: 10/22/2013
WILDFLOWER 1	Paul Shepard, Wildflower Energy Written Testimony: 10/23/2013
WILDFLOWER 2	Taku Futamura, Wildflower Energy Oral Testimony: 10/25/2013
WM 1	Clarles White, Waste Management Written Testimony: 10/9/2013
WM 2	Charles White, Waste Management Written Testimony: 10/22/2013
WN	Ron Liebert, Wheelabrator Norwalk Oral Testimony: 10/25/2013
WPTF 1	Clare Breidenich, Western Power Trading Forum Written Testimony: 9/23/2013
WPTF 2	Clare Breidenich, Western Power Trading Forum Written Testimony: 10/23/2013
WSPA 1	Cathy Reheis-Boyd, Western States Petroleum Association Written Testimony: 10/16/2013
WSPA 2	Catherine Reheis Boyd, Western States Petroleum Association Written Testimony: 10/21/2013
WSPA 3	Mike Wang, Western States Petroleum Association Oral Testimony: 10/25/2013
WSPA 4	Mike Wang, Western States Petroleum Association Oral Testimony: 10/7/2013
YUROK	Nathan Voegeli, Yurok Tribe Written Testimony: 10/2/2013

B. ALLOWANCE ALLOCATION

B-1. Electrical Distribution Utilities

Designation of POU Allowances to Accounts

B-1.1. Comment: The ARB Should Slightly Expand Ability Of POUs To Place Allowances In Other Compliance Accounts To Cover Retail Sales Obligations. The current Cap-and-Trade regulation allows a POU to designate what amounts of administratively provided allowances that the Executive Director should place in the POU's limited use holding account or in the compliance accounts of: 1) an electrical generating facility operated by the POU; 2) an electrical cooperative; or 3) a JPA in which the POU is a member and with which it has a power purchase agreement.

> **Recommendation:** SMUD suggests adding a fourth component to the allowable compliance accounts that can be designated, as follows:
>
> 95892(b)(2)(A): …..in the compliance account of an electrical generating facility operated by a publicly owned electric utility, an electrical cooperative, or a Joint Powers Agency in which the electrical distribution utility or electrical cooperative is a member and with which it has a power purchase agreement, <u>or a federal power authority that is importing electricity products on the behalf of the electric distribution utility</u>; or…
>
> The Proposed Regulation Order recognizes the instances where a federal power authority imports power on the behalf of retail customers of POUs, by explicitly allowing the entry of a zero price in a CITSS transfer agreement if "… the proposed transfer is from a public utility to a federal power authority to cover emissions associated with imported power." (Proposed Regulation Order, § 95921(b)(6)(D), page 199.)
> SMUD would prefer the convenience and flexibility of an option to simply place allowances in the federal power authority's compliance account in these cases. SMUD believes that the added language referring to such transfers in § 95921 imply that a conforming or related change in § 95892, as indicated above, is within the scope of the rulemaking and open for 15-day changes. (SMUD 2)
>
> **Response:** This comment is outside the scope of the proposed amendments, and ARB cannot make changes within section 95892 within this rulemaking. Furthermore, as recognized by the commenter, there are alternative mechanisms for a POU to provide allowances to a federal power authority, and the recommended mechanism is not needed.

Adjustments to EDU Allowance Allocation

B-1.2. Comment: ARB proposes to increase the annual allowance allocation to Anza Electric Cooperative, Inc. (Anza) "because imported electricity serving Anza's ratepayers has greater emissions than staff used to calculate their allocation in the original regulation." ISOR at 19. No change was made to the overall allocation to the electricity sector. Anza is a member and customer of AEPCO, and has a long-term, all-requirements contract with AEPCO for wholesale electric power supply.

AEPCO and Anza support the proposed change to Anza's allowance allocation because it would align ARB's assumptions about the carbon-intensity of the source of Anza's electricity with the actual carbon-intensity of the power that AEPCO delivers to Anza. However, the modification to Anza's allowance allocation will be for naught if AEPCO is not able to report under the MRR on the same basis. AEPCO understands that ARB may withdraw the proposed "system power" reporting option, which the agency proposed in the context of the current MRR rulemaking. AEPCO reiterates that the assumptions behind the allocation to Anza must be consistent with the assumptions that underlie the rules by which AEPCO is required to report under the MRR. For this reason, AEPCO will continue to seek further clarification from ARB on its MRR reporting.

In addition, if ARB rejects AEPCO's proposed changes to the "RPS Safe Harbor" (discussed above), ARB should adjust Anza's allocation further to correct the agency's erroneous assumption that Anza would be obligated to comply with the RPS—an assumption that resulted in a lower allocation to Anza than it would otherwise have received. (AEPCO)

> **Response:** ARB staff appreciates the commenter's support of the change to Anza's allocation. We note that reporting of greenhouse gases is addressed in the MRR and not in this regulation. Nonetheless, we note that AEPCO may report as an asset-controlling supplier pursuant to MRR, or AEPCO may report deliveries from each source used to supply power to Anza. ARB staff recognizes that Anza, as an electrical cooperative, is not obligated to comply with the RPS. However, as explained in the 2011 FSOR for the Regulation[5], ARB staff calculated allowance allocation for all EDUs assuming that they would reduce GHG emissions by an amount equivalent to reductions required of EDUs that are subject to the RPS. This assumption was applied to all EDUs, whether or not they were subject to the RPS, in order to create a level playing field.

B-1.3. Multiple Comments: The Proposed Amendments would also revise section 95892 relevant to the free allocation of allowances to two electrical distribution utilities. As NCPA understands it, this revision is necessary to correct an inadvertent mathematical error that was applied to the allowance allocation formula first adopted by the Board in 2011. As set forth in the ISOR, the changes are being undertaken ". . . based on new information regarding the cost burden for Cap-and-Trade compliance faced by each EDU's ratepayers," and the proposed change to the allocation to the two EDUs is "based on new information regarding the cost burden for Cap-and-Trade compliance faced by each EDU's ratepayers. The ISOR goes on to explain that the

[5] California Air Resources Board. Final Statement of Reasons. October 2011. http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

changes are being made because emissions are different from what was assumed based on previous information. Since allowance allocation methodology was intended to address the distribution of allowances for the duration of the cap-and-trade program through 2020, in order to avoid confusion, it is important for the Final Statement of Reasons that accompanies the regulatory amendments to clearly explain that the changes were made based on the result of a review of the calculations applied to the original data set and methodology, and not based on the provision of any new information regarding the cost burden. (NCPA 1)

Comment. <u>The Regulation Should Clarify That Allocation of Allowances To Electrical Distribution Utilities Is Not Subject To Updating</u>

The proposed revisions make changes to section 95892(a), Table 9-3, by adjusting the allocation of allowances between two electrical distribution utilities. The ISOR states that "staff proposed to change the allocation to two EDUs based on new information regarding the cost burden for Cap-and-Trade compliance faced by each EDU's ratepayers." While M-S-R does not take issue with the revised allocation, it is important that the final SOR reflect the understanding that the allowance allocation methodology proposed by staff and adopted by the Board was not intended to be subject to "updating." Accordingly, M-S-R recommends that the final SOR explanation for the revised allocation reflect the fact that recalculation was based on a correction made to the original cost calculation, and not on new or updated information. (MSR 1)

> **Response:** There had been an inadvertent error in the interpretation of the original data supplied by the two EDUs in question during the development of the allocation approach for electrical distribution utilities. Discussion with the two EDUs, including revisiting data they had supplied, led to the need for a correction. It is not ARB's intent to change allocations on the provision of new and different data by EDUs concerning the cost burden faced by their ratepayers.

Withholding Allowances

B-1.4. Comment: Section 95890, as proposed, would permit ARB to withhold allowances from compliance entities that fail to comply with the GHG Mandatory Reporting Rule (MRR). However, the regulation is unclear if the withholding is permanent or temporary. The regulation should be clarified to eliminate the possibility that ARB would impose a second penalty above the significant daily penalties already authorized under Section 95107 of the MRR for non-compliance. Withholding the entire direct allocation permanently would be a disproportionate penalty for potentially minor violations of the MRR. To clarify, SDG&E and SoCalGas propose the following change to Section 95890 by adding a new Section 95890(i):

> <u>(i)</u> <u>If an entity submits an inaccurate data verification statement, ARB may withhold from the direct allocation an amount equal to the amount of unverified emissions only until such time as the entity has obtained a positive or qualified positive emissions data verification statement.</u> (SEMPRA 2)

Response: ARB staff disagrees that such a change is necessary. The commenter again brings up an issue that they include in their comment reproduced on page 1139 of the 2011 FSOR that was clearly addressed by ARB on page 1140 of the same FSOR.[6] ARB staff reiterates that it is critical that utilities and covered entities comply with MRR and accurately report GHG emissions. Accurate accounting is necessary to a successful Cap-and-Trade Program. If EDUs did not comply, ARB staff would lack data needed to determine an EDU's compliance obligation. For EDUs receiving free allocation, free allocation must be made conditional on a positive or qualified positive verification emissions data report. This provision is necessary to avoid the fulfillment of false claims that would result in misallocation of allowance value.

Deadlines for Designation of POU Allowances

B-1.5. Comment: The Proposed Amendments would revise section 95870 to allocate allowances to electrical distribution utilities on October 14, rather than November 1, for allocations from 2014-2020 annual allowance budgets. Given the timing change and the potential effective date of any amendments adopted by the Board, the October 14 distribution may not be effective until allocation from the 2015 annual allowance budget, and the Proposed Amendments should clarify this. The Regulation should be further revised to make corresponding changes to the September 1 deadline for POUs to inform CARB of the designation of their freely allocated allowances per Section 95892(b)(3). (NCPA 1)

Response: ARB staff anticipates that the proposed amendments will take effect on July 1, 2014. The amendments specify a new allocation deadline of October 24. As the allocation of 2014 vintage allowances has already occurred, the new deadline would first be effective for the allocation of 2015 vintage allowances occurring on October 24, 2014. Therefore, ARB staff believes the comment asking for clarification regarding which budget year's allocation may first be impacted by the proposed amendments is unnecessary.

As to the comment regarding the September 1 deadline for POUs to inform ARB of the designation of their freely allocated allowances, staff also disagrees with this change. Prior to the proposed allocation deadline of October 24, ARB staff must receive the EDU distribution preferences so that the correct quantity of allowances can be transferred to the correct accounts in the Compliance Instrument Tracking System Service (CITSS). ARB staff requires ample time to complete these tasks and ensure they meet all applicable deadlines for allocation. Thus, the September 1 deadline (or the first business day thereafter) is necessary in order to allow ARB staff sufficient time to review all POU allowance designations and prepare and conduct the necessary transfers in the tracking system in a timely manner.

[6] California Air Resources Board. Final Statement of Reasons. October 2011. http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

B-2. Facility Closure

Applicability to Electric Distribution Utilities

B-2.1. Multiple Comments: SCPPA understands from discussions with ARB staff members that proposed new sections 95812(f) and (g) were intended to apply to entities in the industrial sector. This interpretation is supported by the discussion of this section in the ISOR that refers to allocation for “transition assistance and to minimize leakage.” These concepts are associated with allocation to industrial entities, not allocation to electric distribution utilities (“EDUs”), which is to protect ratepayers. However, the intended scope of these provisions is not clear from the wording of the provisions themselves. The first sentence of section 95812(f) refers to entities that receive a direct allocation of allowances pursuant to section 95870. Section 95870 provides for allocation not just to industrial entities, but also to EDUs, universities, public service facilities, legacy contract generators, and natural gas suppliers.

Further confusion arises from the shift, within sections 95812(f) and (g), from references to entities shutting down, to references to facilities shutting or ceasing production in subsections (f)(1), (f)(2) and (g). There is an important distinction between entities and facilities. An entity may operate more than one facility. These sections should be revised to clarify that they apply only to industrial entities.

In particular, it would be incorrect for these sections to apply to EDUs that shut down, or cease production at, one generating facility. In such a case, the EDU would still have the same customer load to serve as it had prior to the shut-down, and the EDU would have to seek alternative sources of power to serve its load. If an EDU were required to return allocated allowances in this situation, it would need to purchase additional allowances on the market and its ratepayers would be adversely affected. It is not comparable to the situation where an entity operates one factory, then closes that factory and has no further emissions liability in California. For these reasons, sections 95812(f) and (g) should be revised to specify that they apply only to entities that receive an allocation of allowances pursuant to section 95870(e) – industrial entities. For further clarity, these sections should be moved to section 95891, Allocation for Industry Assistance, which addresses changes to industrial allocation in a range of circumstances. (SCPPA 1)

Comment: The ISOR states that the addition of the proposed amendments to §95870 is to clarify the requirements applicable to an operator of an eligible facility that receives a direct allocation of allowances, but shuts down operations prior to incurring a surrender obligation. "Direct allocation," in the ISOR's discussion of this section, refers to allocations provided to minimize leakage or to provide transition assistance and assists an entity in meeting a surrender obligation in the compliance period for which the allocation was received.

Since leakage and transition assistance are associated with determination of allowance allocations for industrial covered entities, the proposed surrender requirement appears to be intended to apply to industrial covered entities and is a mechanism that works in tandem with the true-up mechanism established for industrial covered entities. Thus, LADWP recommends that CARB clarify that the proposed surrender requirement applies only to industrial covered entities, and not to electrical distribution utilities. (LADWP 1)

Comment: And on facility shut downs on Section 95812, we just ask that you clarify those provisions are applicable to the industry sector and perhaps move them into that part of the regulation instead of under allowance allocation generally. (NCPA 2)

Comment: Our concern today is that there's some language in Section 95812 that says if a facility that receives allowances is shut down, then those allowances would be returned to the CARB. Now talking with staff, we understand that might be a bit of a ministerial error that that language really only intended to apply to industrial facilities, not to the electric utilities. Of course, this whole program cap and trade is to give in large part utilities and other entities incentives to do the right thing, to reduce greenhouse gases. And walking away from San Juan is one of the things we're doing to reduce our greenhouse gas footprint. So it becomes a disincentive if we think we have that risk. So we're asking that be relocated to Section 95891. (AZUSA)

Comment: Third, there is a provision in the 45-day language requiring that directly allocated allowances must be surrendered if a facility shuts down or ceases production. We understand, as I think George Morrow mentioned earlier, that the staff intends for this provision to apply only to industrial facilities, not electric distribution utilities that shut down fossil fuel generation. However, the phrase of the section is ambiguous. The section should be clarified. (SCPPA 2)

> **Response:** As discussed at the October 25, 2013 Board hearing, ARB staff believes the language in Section 95812(f) and (g) is sufficiently clear. ARB staff intends this provision to apply only to industrial covered facilities, and does not intend to require the return of allowances in the case that an EDU shuts down an electricity generation facility. Consequently, given the stated intent of the provision, ARB staff does not believe that additional text or clarification is required. ARB staff will continue working with EDUs to ensure that our efforts to incentivize greenhouse gas reductions in the electricity generation sector are effectively carried out consistent with State energy goals.

Support for Provision and Public Process

B-2.2. Comment: The staff proposal related to facility closure was not available in the July discussion draft, and therefore this is stakeholder's first opportunity to comment on our understanding of its implications. Alon supports the staffs proposal as it is straightforward and provides needed structure around this issue. Alon recognizes and supports the need for the new provisions related to facility closure, as they provide clarity on an important issue. (PARAMOUNT 1)

> **Response:** Thank you for the support.

B-3. Legacy Contracts

Support for Proposal

B-3.1. Multiple Comments: IEP Supports CARB's Revised Staff Proposal to Provide Transition Assistance Through 2017. Unlike obligated entities that have a reasonable means for passing through the costs of their GHG compliance obligation, generators operating under Legacy Contracts, by definition, do not have a reasonable means of cost recovery for their AB 32 compliance obligation.

Legacy Contracts are defined as: "a written contract or tolling agreement, originally executed prior to September 1, 2006, governing the sale of electricity and/or Legacy Contract Qualified Thermal Output at a price, determined by either a fixed price or price formula, *that does not provide for recovery of the costs associated with compliance with this regulation…"*

CARB's Revised Staff proposal to provide transition assistance to legacy contract generators through 2017 is a substantial improvement to addressing the compliance costs that cannot be reasonably recovered due to a pre-AB 32 legacy contract. IEP recommends that the CARB Board approve the *Revised Staff Proposal for Legacy Contract Treatment in the Cap and Trade*. In addition, IEP agrees that it is appropriate to develop language to address the Revised Staff Proposal in a 15-day comment period following the October Board Meeting. (IEPA 1)

Comment: Resolving Legacy Contracts Does Not Create Perverse Incentives. Some have suggested that providing transition assistance to the remaining legacy contract generators for the duration of their existing legacy contacts would create a perverse incentive in that "those who renegotiated could have received less favorable treatment than those who did not renegotiate."[7]

As a practical matter, all generators with pre-AB 32 contracts without GHG cost recovery in a position to renegotiate their contracts did indeed renegotiate. These contracts should be presumed to be fairly balanced (otherwise they would not have been renegotiated) and no longer under CARB's purview for resolution.

For all other legacy contracts, CARB requires "an attestation under penalty of perjury under the laws of the state of California that…. the legacy contract generator made a good faith effort, but was unable to renegotiate the legacy contract with the counterparty to address recovery of the costs of compliance with this regulation."[8] Hence, all legacy contract generators must show an attempt to renegotiate with their contract counterparties to qualify for transition assistance.

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[7] Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Staff Report: Initial Statement of Reasons, Page 18.

[8] Appendix E: Proposed Regulation Order, Section 95894(a)(3), page 158.

Given these requirements, it is clear that the legacy contracts that remain do not have alternative options available. They are relying on CARB to provide a comprehensive solution. CARB's proposal to aid legacy contracts that are still stranded, by extending the transition assistance through 2017, is helpful. (IEPA 1)

Comment: SMUD also appreciates the proposed changes that will provide 2015 allowances to cover 2013 and 2014 emissions associated with "legacy contracts" – electricity or qualified thermal output contracts that were signed prior to the Cap-and-Trade program and that have not been able to be altered to include compensation for the compliance instrument costs associated with the contracts. (SMUD 2)

Comment: Legacy Contracts: Calpine strongly supports and appreciates CARB's proposed resolution of the legacy contract issue. Where a counterparty to a legacy contract is itself scheduled to receive an allocation for industrial assistance, but will not face an increase in its steam or electricity costs due to the legacy contract, the emissions attributable to generation of steam and/or power pursuant to that contract should be deducted from the counterparty's allocation and provided to the generator instead. The Proposed Amendments satisfy fundamental fairness in this respect by providing relief to the generator for the entire life of the legacy contract and withholding from the counterparty the windfall it would otherwise receive as a result of its unwillingness to renegotiate the contract terms. We likewise support CARB's revised proposal, which would extend the transitional assistance for legacy contracts with counterparties who are not receiving an allocation of industrial assistance through the second compliance period. Calpine urges the Board to adopt the Proposed Amendments' provisions concerning legacy contracts and direct staff to undertake a 15-day rulemaking consistent with staff's revised proposal. (CALPINE 1)

Comment: CARB's Proposed Resolution of The Legacy Contract Issue Is Consistent With Both Fundamental Fairness And The Overall Program Goals And Should Therefore Be Adopted. Calpine strongly supports CARB's approach to resolving the long-standing issue of how best to provide measured relief to generators subject to legacy contracts entered into prior to the enactment of Assembly Bill ("AB") 32 that do not allow for recovery of GHG compliance costs for electricity and/or thermal energy delivered pursuant to the contract.

Calpine has consistently advocated for a fair resolution of the legacy contract issue[9] and has, whenever possible, renegotiated pre-AB 32 contacts to address GHG costs.

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[9] *See* Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Proposed Regulation to Implement the California Cap-and-Trade Program, at 3-10 (Dec. 9, 2010), *available at*: http://www.arb.ca.gov/lists/capandtrade10/253-carb_letter_re_cap-and-trade_20101209.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Proposed 15-Day Modifications to the Proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, at 10-12 (Aug. 11, 2011), *available at*: http://www.arb.ca.gov/lists/capandtrade10/1450-8-11-2011_calpine_comments_re_proposed_15-day_modifications_to_proposed_ca_cap_on_ghg_emissions.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Second Proposed 15-Day Amendments to the Proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, at 7-9 (Sep. 27, 2011), *available at*: http://www.arb.ca.gov/lists/capandtrade10/1658-9-27-2011_calpine_comments_re_proposed_15-day_modifications_to_proposed_ca_cap_on_ghg_emissions.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Public Workshop to Discuss Linking the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation to Western Climate Initiative Jurisdictions, at 9-11 (Feb. 17, 2012), *available at*: http://www.arb.ca.gov/lists/feb-3-link-wci- ws/7-2-17-2012_calpine_comments_re__cap_and_trade_workshop.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough,

Despite Calpine's good faith efforts to bring our counterparties to the negotiating table, we have not been able to renegotiate four remaining legacy contracts to allow for the pass-through of compliance costs associated with deliveries of electricity and/ or steam from our combined heat and power ("CHP") facilities.[10]

The Proposed Amendments strike the right balance in resolving this issue: Where a legacy contract counterparty will receive an allocation for industrial assistance, but will not experience an increase in its steam or electricity costs due to the existence of the legacy contract, the emissions attributable to generation of steam and/or power pursuant to that contract should be deducted from the counterparty's allocation and provided to the generator instead. As CARB states in the Initial Statement of Reasons ("ISOR") for the Proposed Amendments, "[b]y adjusting the industrial counterparty's allocation and providing that to the generator, this proposal corrects the otherwise missing incentive and also encourages parties to renegotiate. Since the adjustment is equitable across the length of the legacy contract, this proposed approach would allocate to the legacy contract generator for the entire contract length for those with industrial counterparties."[11] We agree that the Proposed Amendments correct the incentives and are wholly consistent with principles of fundamental fairness and the underlying rationale for providing transitional assistance to industry in the first place: To the extent that an industrial entity is insulated from an increase in its energy costs due to a legacy contract, it should not be receiving an allocation intended to offset that increase.

Calpine greatly appreciates CARB's willingness to work with affected parties to develop a solution that best supports the overall program goals and does not act as a disincentive to continued operation of CHP facilities. We likewise support CARB's revised proposal, which would extend legacy contract allocations with counterparties who are not receiving industrial assistance until the end of the second compliance

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re: Draft of Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments Issued by Linked Jurisdictions, at 12-14 (Apr. 13, 2012), *available at*: http://www.arb.ca.gov/lists/april-9- draft-reg-ws/14-4-13-2012_calpine_comments_re_draft_amendments_to_ca_cap_on_ghg_emissions- linked_jurisdictions.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Comments on Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market- Based Compliance Mechanisms, at 19-20 (June 21, 2012), *available at*: http://www.arb.ca.gov/lists/capandtrade2012/9-6-21-2012_calpine_comments_re_cap-and-trade.pdf (hereinafter, "June 2012 Comments"); Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Comments on Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments issued by Linked Jurisdiction, at 3-4 (Jan. 23, 2013), *available at*: http://www.arb.ca.gov/lists/capandtradelinkage12/25-1-23-2013_calpine_comments-_linked_jurisdictions.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Barbara McBride, re: Comments on CARB Staff Workshop regarding Proposed Adjustments to the Cap-and-Trade Program's Treatment of Universities, "But For" CHP , and Legacy Contracts, at 1-11 (May 21, 2013), *available at*: http://www.arb.ca.gov/lists/com-attach/13-may1-unilegbutfor-ws-VGEBKlZlA2EEL1Bi.pdf; Letter to Hon. Mary D. Nichols, Chairman, from Kassandra Gough, re: Comments on CARB Discussion Draft of Proposed Amendments to the Cap-and-Trade Regulation and July 18, 2013 CARB Public Workshop, at 3-10 (Aug. 2, 2013), *available at*: http://www.arb.ca.gov/lists/com-attach/67-cap-trade-draft-ws- VmQCNFBgWDhWfQQ0.pdf ("August 2013 Comments").

10 *See* Steam Purchase and Sale Contract between Olam West Coast, Inc. and Calpine Gilroy Cogen, L.P. (dated Jan. 20, 1986); Steam Purchase and Sale Contract between Rava Family Ltd. Partnership and Calpine King City Cogen, LLC (dated July 31, 1987); Cogeneration Project Development and Supply Agreement between Sunsweet Growers Inc. and Calpine Greenleaf, Inc. (dated April 15, 1988); Energy Purchase and Sale Agreement between USS-Posco Industries and Los Medanos Energy Center LLC (dated Dec. 21, 1998). All of Calpine's legacy contracts, and amendments thereto, have previously been described in submittals to CARB.

11 Staff Report: Initial Statement of Reasons, Proposed Amendments To The California Cap On Greenhouse Gas Emissions And Market-Based Compliance Mechanisms, at 17 (Sept. 4, 2013), *available at*: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf ("ISOR")

period.[12] The revised proposal would provide welcome relief for two of Calpine's four legacy CHP contracts, which are not with counterparties receiving industrial assistance. We urge the Board to adopt staff's proposed resolution of this issue and direct staff to undertake a 15-day rulemaking with respect to the extension of legacy contract allocations through the second compliance period. (CALPINE 1)

Comment: My name is Bill Buchan representing Cardinal Cogen, a 48 megawatt power plant providing stream power and chilled water to Stanford University. We operate under a legacy contract that was put in place well before AB 32. We negotiated and we were unable the pass on any of the cost, which are considerable, under cap and trade. While the current regulation does not address legacy contracts, the new proposal that staff provided on October 16th and we urge support of this. It provides transition assistance through the end of the second compliance period and does so on in fair way amongst combining power plants as well as relative to other covered entities. This is something that the original draft regulations that went out in July did not do. So we urge support of the October 16th proposal by staff for legacy contracts. And if approved, we at Cardinal Cogen pledge to work with staff to develop a detailed regulation with staff. We have submitted our comments in writing. And thank you for the opportunity to testify. (CARDINAL 2)

Comment: Good morning. I'm appearing on behalf of OLS Energy Chino. We operate a 30 megawatt CHP facility at the California Institute for Men in Chino, California. Since 1988, OLS has provided Southern California Edison with 26 megawatts of power under a legacy PPA.

The modified staff proposal issued on October 16th provides transition assistance through the second compliance period for the legacy contract holders. OLS is very appreciative of all the efforts of staff and others to come up with this proposal, and we greatly support it. We're also appreciative of the efforts of staff on this regard. OLS also submitted in its written comments some tweaks to the definition of legacy contract to remove any ambiguity. We ask that you take these into consideration as you go forward. Thank you very much. (OLS 2)

Comment: Good morning. My name is Ron Liebert with the Law Firm Ellis Schneider and Harris. I'm here on behalf of the Wheelabrator Norwalk. Wheelabrator Norwalk is a non-standard QF that provides steam to a State hospital. The Norwalk facility is operating under a pre-AB 32 legacy contract that does not take into account for greenhouse gas costs. We, therefore, support the staff proposal to provide transitional assistance to legacy contracts for the second triennial compliance presented to ensure that legacy contract generators are not detrimentally burdened financially as a result of the inability to pass through GHG costs. We believe the staff proposal is a fair and balanced approach. We also request that the ARB adopt the 45-day language today so that legacy contract generators will have certainty that they need that they will qualify for transitional assistance. Thank you. (WN)

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[12] CARB, Revised Staff Proposal for Legacy Contract Treatment in Cap-and-Trade (Oct. 16, 2013), *available at*: http://www.arb.ca.gov/cc/capandtrade/legacy-contract-proposal.pdf.

Comment: While ARB staff have made progress on legacy contract issues in the draft regulation, Cardinal Cogen remains in a situation where it cannot reasonably recover greenhouse gas compliance costs, and fairness issues have now arisen between those entities serving public universities and those serving private universities if the current draft regulation is approved. To adequately address this legacy contract issue, we ask that the ARB Board approve the new ARB staff proposal of October 16, 2013, which extends the sunset date for transition assistance for legacy contracts through 2017. This is consistent with the draft regulation whereby ARB staff proposed to extend transition assistance for industry through 2017. (CARDINAL 1)

Comment: My name is Taku Futamura. I'm the asset manager for Wildflower Energy. I'm here today to indicate our support to transitional assistance to legacy contract. Wildflower Energy has pre-AB 32 legacy contract with a third power marketer that's not explicitly address greenhouse gas costs. Wildflower owns two fast starting peaker plants in Southern California and that are covered by pre-AB 32 legacy contract. Over the past four years, Wildflower has been unsuccessful in its efforts to renegotiate the legacy contract. And as a result, Wildflower faces serious economic risk without by the ARB today. We believe that the staff's proposal is fair and will achieve the ARB's policy objective of encouraging parties to renegotiate their contracts. I also want to take a second to thank the ARB staff for their hard work on this issue and taking into account the various interests and issues faced by a very diverse group of stakeholders. We request that the ARB approve the proposed revisions to Section 95894 today. Thank you. (WILDFLOWER 2)

Comment: a. Eligibility Criteria. In the Proposed Amendments, staff put forth eligibility criteria for legacy contracts to qualify for relief applicable to PEC (Section 95894):

- Contract was executed before September 1, 2006;
- Contract does not allow for recovery of the costs associated with compliance with the Cap and Trade Regulation;
- Contract remains in place and has not been subsequently amended to address GHG compliance costs; and
- The Legacy Contract holder has made a "good faith" effort to renegotiate with contract counterparty to address GHG costs issues.
-

PEC supports these straightforward criteria.

b. Process for Receiving Allocations

The Proposed Amendments provide a process for allocation of allowances to Legacy Contract Generators in newly drafted Section 95894. The process generally consists of a request by the legacy contract generators and a subsequent eligibility determination by the CARB Executive Officer. In order to receive allowances eligible for 2013 and 2014 compliance on October 15, 2014, legacy Contract Generators must submit the following information in writing via certified mail to the Executive Officer by June 30, 2014, or within 30 days of the effective date of this regulation, whichever is later:

- A letter stating the covered entity name, identification of counterparty, and a statement requesting transition assistance for emissions reported and verified for the 2012 data year.
- A copy of portions from the legacy contract for which it is seeking an allocation as to the dates of effective commencement and cessation of the term of the contract, terms governing price per unit of product; and signature page.
- An attestation, under penalty of perjury, that the contract meets the eligibility criteria listed above and that the Legacy Contract Generator has conducted renegotiation efforts in "good faith."
-

PEC supports this simple administrative criteria. (PANOCHE 1)

Comment: Finally, we support staff's proposal to reduce allowance allocations to industrial third parties under contract with a legacy contract generators for the emissions associated with their steam and electricity purchases. As staff notes, since emissions associated with a legacy contract do not have an emissions cost from the perspective of the steam or electricity purchaser, there is no incentive on the part of the industrial third party to reduce those emissions. Allocating the allowances associated with those emissions to the legacy contract generator instead will correct the missing incentive and encourage renegotiation. (NRDC 2)

Comment: It Is Important for CARB to Make Decisions Now Regarding How Allowances Will Be Allocated to Legacy Contract Generators in the Future. IEP appreciates CARB's Revised Staff Proposal which takes action now to provide transition assistance to legacy contract generators through 2017. In the Proposed Amendments, CARB proposes to allocate 2015 vintage allowances to legacy contract generators for transition assistance for 2013 and 2014 in part because there are no more 2013 or 2014 vintage allowances available to allocate for this purpose. Thus, it will be important for CARB to make decisions now regarding how allowances will be divvied up in the out years to be sure that sufficient allowances will be available to provide transition assistance through 2017.

IEP supports CARB staff's proposal to open up a subsequent 15-day comment period following the October Board hearing to refine language consistent with providing transition assistance through 2017. It is appropriate for CARB to address legacy contracts that extend beyond 2015 now rather than waiting until 2017 when the compliance instruments are due. (IEPA 1)

Response: Thank you for the support.

B-3.2 Comment: Under the current draft cap and trade regulation, facilities operating under a legacy contract supplying heat and power to a publicly-owned university will be allocated allowances for the duration of the legacy contract, even if it stretches through to the end of the third compliance term (see Section 95870(f) for Universities). However, facilities like Cardinal Cogen, operating under a legacy contract supplying heat and power to a privately-owned university will be allocated allowances for 2013 and 2014 compliance years only, regardless of the duration of the legacy contract (see Section 95870(g)). This draft regulation is not fair in the treatment of electric generation facilities serving the same sector (education), providing different benefits solely on the basis of the ownership status of the host university (i.e. allowances in the second and third compliance period). (CARDINAL 1)

> **Response:** The proposal is to allocate allowances to legacy contract generators through the end of the second compliance period. If the generator has a legacy contract with a counterparty that has been approved to receive an allowance allocation as an industrial entity, then the allowance allocation to the legacy contract generator will come from the industrial counterparty, and will continue to come from the industrial counterparty for the life of the contract, even if the contract extends beyond 2017. The proposal does not specifically call out or state that the allowance allocation will occur for generators with a public university counterparty and not for a generator with a private university counterparty. The eligibility requirements for the generator to receive allocation are stated in section 95894. The commenter may be confusing the purpose of the allowance allocation to universities and the purpose of the allowance allocation to legacy contract generators, and the calculation and transfer of those allowances. The proposal to provide transition assistance to legacy contract generators allows for the transfer of allowances allocated to an industrial counterparty to the legacy contract generator if the industrial counterparty received an allowance allocation. The purpose of allocation to universities is to recognize their early actions to reduce GHG emissions by investing in energy efficiency, renewable energy, and other emissions reduction strategies at their campus facilities, and to recognize their leadership in research and development of emissions-reducing technologies. The proposal to address legacy contract generators does not differentiate based on whether it is a public or private university. Additionally, the revised proposal is to allocate allowances through the second compliance period. Staff included regulatory language that reflects this revised proposal in the 15-Day Modifications.

Eligibility Criteria

B-3.3. Comment: c. <u>Process for Determination of Eligibility</u>

PEC understands the intent of Section 95894(b) to be relatively straightforward, but seeks clarity in either Board Resolution or in response to comments in the Final Statement of Reason that the “Determination of Eligibility” is a compliance process by which CARB will review and process the filings. PEC further believes that such information must be treated by CARB as confidential in that sensitive market and pricing information is required for submittal.

PEC supports the need for CARB Staff to review sufficient detail to determine whether the generator qualifies for the proposed transition relief. However, PEC requests that CARB confirm that the process will be an internal compliance process conducted by CARB, not subject to a public review and comment process, especially as market-sensitive pricing information is required for submittal. (PANOCHE 1)

> **Response:** The commenter requests clarification regarding the process to determine eligibility for allowance allocation under this provision. The process contemplated by ARB staff to review the appropriate data will not be subject to a public review and comment process. Each entity that considers itself a legacy contract generator must first apply to ARB for an allowance allocation, pursuant to section 95894. ARB staff will review the information and data submitted. ARB staff anticipates that some of the data and information requested by ARB staff and provided by an applicant will be considered by some entities as confidential. Pursuant to title 17, California Code of Regulations, section 91022, data received by ARB that is submitted as confidential is subject to special provisions related to its disclosure. The reasons an entity may use to support the confidential information designation and nondisclosure are located at title 17, California Code of Regulations sections 91022(c)(1) through (6). Notably, section 91022(d) indicates that the supporting information may be submitted prior to a request for release of the information.
>
> If data are considered confidential by an entity, the information should be transmitted to ARB in such a way so that it is labeled as confidential, as outlined in section 91022(d). Information and data transmitted to ARB will be held confidential, to the extent possible, pursuant to ARB's regulations and pertinent Government Code statutes.

B-3.4. Multiple Comments: We request that the ARB clarify the language for 'transitional assistance' and the applicability to Non-Standard QF contracts. To that end, we are concerned with language in the definition of "Legacy Contract" that states "legacy contracts exclude contracts that *give rise to* a Legacy PPA Amendment". We do not feel that ARB intended to exclude CSUCI's plant and the other Non-Standard Contracts from the transitional assistance. Our first recommendation would be for the ARB to recognize that the Legacy PPA Amendments from the QF settlement were not appropriate for Non-Standard Legacy Contracts. (CSU 1)

Comment: The definition of "Legacy Contract" included in the Proposed Amendments should be revised to make clear that the exclusion of contracts "that gave rise to a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision D-10-12-035, with a privately owned utility as defined in Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU)" applies only to contracts for which a Legacy Amendment was actually executed. As explained above, OLS and a small number of other CHP facilities with Non-Standard QF Contracts were not in a position to execute, and therefore did not execute, the Legacy PPA Amendment. The text "gave rise to a

Legacy PPA Amendment" may be too vague for such generators to obtain relief, because it is not clear what "gave rise to" is intended to cover.

> **Recommendation:** Therefore, OLS respectfully requests that CARB modify the Proposed Amendments by changing the second sentence in the definition of "Legacy Contract" as follows (additions are shown with double-underline and deletions with strikethrough):
>
> For purposes of this regulation, legacy contracts exclude contracts ~~that gave rise to~~ with respect to which a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision number D-10-12-035, was executed with a privately owned utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU).

This modification makes clear that CHP QF generators who were not in a position to execute and therefore did not execute a Legacy PPA Amendment, such as generators with Non-Standard QF Contracts, will not be precluded from the relief granted by the new Section 95894. That result is fair and reasonable, because these CHP QF generators are subject to contracts that do not provide a reasonable means to recover GHG Compliance Costs, and they neither have had, nor will have, a meaningful opportunity to amend those contracts. (OLS 1)

> **Response:** It is ARB staff's intent to include legacy contracts that are considered a non-standard agreement by the CPUC and did not choose one of the options under the CHP Settlement as eligible for an allowance allocation. The 15-Day Modifications to the definition of "Legacy Contract" clarified this point.

B-3.5. Comment: Furthermore, we recommend clarification in the definition of "Legacy Contract Emissions" with regard to the sentence "Legacy contract emissions do not include emissions that are *included in the calculations of cost* under the CPUC's Qualifying Facilities and Combined Heat and Power Program Settlement," Again, we believe this is not clear because we are not aware of any such data in the CHP settlement.

We would propose that the ARB add definitions of both non-standard QF contract and Legacy PPA Amendment and eliminate the reference to the emissions because we are not aware that any such data exists.

We have discussed language revisions with other non-standard QF contract holders and agree with their proposed language herein.

"Non-Standard QF Contract" means a contract that does not include standard pricing based on short-run avoided costs, as set and adjusted from time to time by the California Public Utilities Commission (CPUC).

“Legacy PPA Amendment” means the pro forma standard amendment that was offered, under the Combined Heat and Power Program Settlement adopted by the California Public Utilities Commission (CPUC) by Decision number D-10-12-035, to combined heat and power qualifying facility (QF) generators that had existing QF contracts.

“Legacy Contract” means a written contract or tolling agreement, originally executed prior to September 1, 2006, governing the sale of electricity and/or Legacy Contract Qualified Thermal Output at a price, determined by either a fixed price or price formula, that does not allow for recovery of the costs associated with compliance with this regulation; the originally executed contract or agreement must have remained in effect and must not have been amended since September 1, 2006 to change or affect the terms governing the California greenhouse gas emissions responsibility, price or amount of electricity or Legacy Qualified Thermal Output sold, or the expiration date. For purposes of this regulation, legacy contracts exclude contracts that give rise to a Legacy PPA Amendment, ~~as defined in the Combined Heat and Power Program Settlement pursuant to CPUC Decision number D-10-12-035, with a privately owned utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU),~~ but does not exclude generators with Non-Standard QF Contracts that did not execute a Legacy PPA Amendment. A legacy contract does not apply to opt-in covered entities.

“Legacy Contract Emissions” means the emissions calculated, based on a positive or qualified positive emissions data verification statement issued pursuant to MRR, by the Legacy Contract Generator, that are a result of either electricity and/or Qualified Thermal Output sold to a Legacy Contract Counterparty, and calculated pursuant to section 95894 of this regulation. ~~Legacy contract emissions do not include emissions that are included in the calculation of cost under the CPUC’s Qualifying Facilities and Combined Heat and Power Program Settlement pursuant to CPUC Decision number D-10-12-035~~. (CSU 1)

> **Response:** ARB staff does not agree with the proposed deletions to the definition of the term “Legacy Contract Emissions.” The sentence the commenter suggests to be deleted is important because it serves to exclude emissions from electricity generated by facilities that did sign an agreement under the CHP Settlement. The terms of the settlement included formulas to determine reimbursement costs, which also reflect the GHG costs. ARB staff proposed edits to the definition of “Legacy Contract” in the 15-Day Modifications, which help to clarify this point.

B-3.6. Comment: Only Contracts Executed Before August 15, 2005, Should be Considered Legacy Contracts. ARB should amend the date before which an executed contract qualifies as a legacy contract from September 2006, to August 15, 2005, because amendments to AB 32 as of August 15, 2005, included broad limits on GHG emissions. The basis for the use of August 15, 2005, is also consistent with CPUC decisions interpreting whether generators foresaw the imposition of a carbon price in the electric sector. In fact, potential governmental action imposing GHG compliance costs on fossil fuel power plants in California was foreseeable prior to August 15, 2005.[13]

For example, CPUC Decision 12-12-002[14], dated December 20, 2012, cites August 15, 2005, as the date a firm cap was introduced by the Legislature. Similarly, CPUC Decision 12-04-046, dated April 4, 2012, states that "contracts negotiated and executed when AB 32 was working its way through the legislature should have taken the potential impacts of AB 32 into consideration. Even those negotiating contracts shortly before then might also have reasonably foreseen that this issue could arise."[14]

IOU counterparties and, presumably other generators, are sophisticated commercial parties with experienced commercial, regulatory, and legal teams aware of the potential for GHG costs prior to the actual date of passage of AB 32. The CPUC agrees with this assessment; and we urge ARB to provide a consistent conclusion.

> **Recommendation:** PG&E therefore recommends the following changes to the definition of a "Legacy Contract" laid out in Section 95802:
> "Legacy Contract" means a written contract or tolling agreement governing the sale of electricity and/or qualified thermal energy from an electric generating facility or cogeneration facility at a price, determined by either a fixed price or price formula, that was originally executed prior to August 15, 2005 ~~does not allow for recovery· of the costs associated with compliance with this regulation~~; the originally executed contract or agreement must have remained in effect and must not have been amended since ~~September 1, 2006 August I5, 2005~~ execution to change or effect the terms governing the California greenhouse gas emissions responsibility, price or amount of electricity or Qualified Thermal Output sold, or the expiration date. For purposes of this regulation, Legacy Contracts exclude contracts that ~~give rise to~~ are eligible to execute a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision number D-10-12-035, with a privately owned utility as defined in the Public Utilities Code Section 216 (referred to as an Investor Owned Utility or IOU). This definition of a "Legacy Contract" does not apply to opt-in covered entities. For purposes of this regulation, Legacy Contracts also exclude contracts as to which a court or arbitrator(s) in a dispute resolution proceeding between the parties to the agreement finds that, at the time the agreement was executed, the

13 For example, in 2004, the CPUC proposed a GHG Cap-and-Trade Program in an Order Instituting Rulemaking (OIR) and, in its comments on the OIR, the Independent Energy Producers Association mentioned independent generators intemalizing the costs ofGHG emissions reductions in offers submitted into the utility procurement processes. AB 32 was introduced into the Califomia Legislature in December 2004. In June 2005, GHG emissions reduction targets were established for Califomia by the Executive Order S-3-05.

14 D. 12-12-002 is available at http://docs.cruc.ca.gov/PublishedDocs/Published/GOOO/M041/K695/41695122.PDF
"D.l2-04-046, page 6 I available at http://docs.cpuc.ca.gov/PublishedDocs/WORD PDF/FINAL DECISION/164799.PDF

seller understood that if there were a future change in the law that imposed a cost on the facility because of its greenhouse gas emissions, the seller would be responsible for paying that cost. (PGE 2)

Response: ARB staff has determined September 1, 2006—the same month in which AB 32 was signed—is the appropriate date to apply as a threshold for consideration for the inclusion of the cost of compliance with this regulation within a legacy contract. The determination about whether the compliance obligation for the electricity sector would be based on a load-based approach (retail supplier holds the obligation), or an emissions-based approach (generator holds the obligation) was not publically vetted through ARB's public process under the Cap-and-Trade Program until after this date.

B-3.7. Multiple Comments: "Legacy Contract Generators" are defined as CHP parties with an unamended contract signed prior to 2006 with a counterparty other than an IOU. SCE supports this distinction, as it accurately acknowledges the amendments offered to all IOU-contracted CHP parties in 2012 pursuant to the CHP Settlement. Due to these "Legacy Amendments," any IOU-contract CHP facility was given the opportunity to amend its existing contract to include payment for GHG. It would be inappropriate to allow a facility who was offered but did not accept one of these options – presumably to retain the higher payment structure under their Legacy Agreement – to "double dip" from the ARB and receive additional payment for its GHG obligations. (SCE 1)

Comment: ARB Should Clarify that Entities Covered by CPUC Decision D-10-12-035 are Ineligible. PG&E understands that ARB does not intend for transitional assistance to be provided to entities eligible to execute standard contracts pursuant to the Combined Heat and Power Program Settlement approved by CPUC D. 10-12-035. Above, PG&E also suggests an edit to "Legacy Contract" to clarify this understanding. (PGE 2)

Response: The intent of the provision is to provide transition assistance to covered entities only if there is a signed contract that meets the proposed eligibility requirements. ARB staff does not intend to exclude covered entities based on their previous eligibility to sign a contract under the CHP settlement, pursuant to the CPUC Decision D-10-12-035, if they did not enter into an agreement under that settlement.

B-3.8. Comment: The Proposed Regulation inappropriately provides a free allocation of allowances to the Panoche Energy Center (PEC), a generator that: (1) had notice of the potential for future GHG costs; and (2) bargained for the costs associated with cap-and-trade compliance in their contracts. PG&E opposes ARB's proposed "legacy contract" definition to the extent that it would provide PEC a windfall by allocating allowances to the generator at the expense of California taxpayers after the generator has already been and continues to be compensated by PG&E customers. PG&E proposes simple revisions to the definition of "legacy contract" so that generators like PEC that were aware of and agreed to assume responsibility for GHG compliance costs bear those costs.

The Definition of Legacy Contract Should Exclude Contracts in Which the Seller Agreed to Assume Responsibility for GHG Costs - **It** is unwise policy for ARB to provide transition assistance to generators like PEC that foresaw the possibility of GHG compliance costs and knowingly agreed to assume responsibility for those costs in their contracts. This opinion is also consistent with the CPUC direction, which defers to the parties as to whether their contracts addressed GHG costs.[15] The CPUC previously stated that it is "not in the business of bailing unregulated market participants out of their own past missteps."[16] PG&E is concerned that ARB's proposed assistance is doing just that.

To the extent the parties to the contract cannot agree whether the generator knowingly assumed GHG compliance cost risk at the time the contract was executed or are unable to renegotiate their contract to further address GHG costs, such matters can be resolved by an arbitrator in a dispute resolution proceeding. Where a court or arbitration decision has found that a generator foresaw the possibility of GHG compliance costs and knowingly agreed to assume responsibility for those costs in their contracts, ARB should not provide free allowances to the generator. (PGE 2)

> **Response:** The commenter claims that the responsibility for the cost of GHG emissions was discussed during contract negotiations. However, ARB was neither party to the contract negotiation nor the subsequent arbitration process. ARB staff will evaluate each request for transition assistance to determine whether the documentation submitted demonstrates the eligibility requirements have been met to receive allocation. Legacy contract generators must re-apply to ARB each year and meet the eligibility requirements every year to receive an allowance allocation, pursuant to section 95894.
>
> More specifically, the proposed amendments include the requirement that an attestation be submitted declaring certain statements are true, under penalty of perjury. One of the attestations, which must be signed every year, is that the legacy contract does not allow the covered entity to recover the cost of legacy contract emissions from the legacy contract counterparty purchasing electricity and/or Qualified Thermal Output from the unit or facility. ARB staff will evaluate each request to determine if the application and supporting documentation meets the eligibility requirement.

Calculating Legacy Contract Allowance Allocation

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[15] See 0.12-04-046, page 61: "parties are in a better position to address... whether the existing contract may have taken the passage of AB 32 into consideration." Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD PDF/FINAL DECISION/164799.PDF and Rulemaking (R.) 11-03-012, page 16: "a dispute about whether a given contract already includes a GHG costs either explicitly or othenvise raises a factual question that is more appropriately determined for each contract through the contract's dispute resolution processes." Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/GOOO/M040/K631/40631611.PDF

[16] See D. 12-04-046, page 61 available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD PDF/FINAL DECISION/164799.PDF

B-3.9. Multiple comments: The True-Up Is Critical To Ensuring That Generators Are Not Burdened With Any Allocation Shortfall - As noted above, a shortfall in the allowance allocation will result if there is an increase in legacy contract generators' production or output of electricity or steam and associated emissions compared to prior years. This deficit will be more pronounced for energy efficient facilities that are increasingly utilized as the declining GHG emission cap under the Regulation incentivizes increased dispatch from such facilities. Thus, in order to ensure that emission allowances are provided for all electricity and steam sold pursuant to a legacy contract (and to ensure the fair and equitable treatment of legacy contract generators whose counterparty is not receiving allocations for industry assistance), CARB staff should include a "true-up" for allocating allowances in its forthcoming amendments to implement the Legacy Contract Proposal. As noted above, providing such a true-up is consistent with the allocation calculation methodology in sections 95894(c) of the Proposed Regulation Order for counterparties receiving allowance allocations for industry assistance. Significantly, there is no policy justification for treating legacy contact generators differently in this regard based on the nature of the counterparty. Thus, any such discrimination would arbitrarily and unfairly penalize legacy contract generators whose counterparty is not receiving allocations for industry assistance, and would not provide any GHG emissions reduction benefit.[17] (PH 1)

Comment: While the current draft is clearly unfair and creates an unreasonable economic hardship for the Cardinal Cogen, we believe that the situation can be easily resolved by extending the transition assistance for legacy contracts through 2017, as proposed by ARB Staff on October 16, 2013. By extending the transition assistance through 2017, the legacy contract issue involving Cardinal Cogen and Stanford University will be resolved. Making this change would create regulatory integrity in the cap and trade program and a fairer environment between all facilities providing heat and power to universities, regardless of whether the university is publicly-owned or privately owned. This change would also create consistency between 3rd party combined heat and power plants and other industrial sectors as all will fairly have their transition assistance extended through 2017.

Cardinal Cogen urges the Board to request that the ARB staff resolve the unfair situation that would develop between facilities supplying heat and power to public and private universities if the current draft regulation is approved. As its legacy contract is not able to be renegotiated, Cardinal Cogen asks the Board to approve the new ARB staff proposal to extend legacy contract transition assistance through 2017 with true-up provisions so that our facility will not bear unreasonable, unrecoverable costs. Cardinal Cogen looks forward to working with the ARB staff in November to finalize the wording of the October 16, 2013 proposal during the 15 day comment period. Thank you for this opportunity to comment on this important regulation. Should you have any questions regarding these comments or the revised benchmark, please call me at (650) 723-1779. (CARDINAL 1)

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[17] For consistency, we also note that the allocation to University Covered Entities and Public Service Facilities should also use the most current available data and include a true up for subsequent allocations. See Proposed Regulation Order, § 95891(e)(2).

Comment: First, I'd like to thank all the Board members and staff for your attention to legacy contracts. We support the proposal that was issued on October 16th and very much appreciate it. It recognizes the reality in the marketplace for these generators. We would ask on that that as staff goes to develop the 15-day proposal that they consider the levelling of the playing field for those legacy contracts that are addressed here with those that have industrial counterparties so that the base year and the true-up provisions are the same. These are meaningful in the amounts of millions of dollars for these entities. And we submitted written comments on that. The rest of the time I'd like to devote to something else.

And by the way, we do think the Resolution as prepared on the legacy contracts can include this kind of technical amendment. (PH 2)

Comment: The Most Current Data Available Should Be Utilized To Calculate GHG Emission Allowances - To help ensure that allowance allocations accurately reflect current operating output (and to avoid any shortfall to generators), CARB should use the data available for the facility emissions and the amount of electricity and steam sold in the prior calendar year in which the allocation is made. Under the Proposed Regulation Order, unlike the relief provided to generators whose counterparty receives allowance allocations for industry assistance, the initial allocation for legacy contract generators whose counterparty does *not* receive allowance allocations for industry assistance will use 2012—not 2013 data. As CARB staff is aware, facility output varies based market demand, production capacity, the specific terms of the legacy contract, and facility downtime and maintenance. In particular, utilizing data from the 2012 recessionary period would result in an under-allocation of allowances to legacy contract generators. Further, the expected shortfall from using such 2012 data will be more pronounced for efficient facilities that experience increased demand as the annual GHG emissions cap declines to incentivize the dispatch of more efficient facilities. Thus, by using the most current data, there is less risk that legacy contract generators would incur the likely substantial costs to purchase allowances in advance of receiving a subsequent true-up (discussed below). Consistent with the provisions of the Proposed Regulation Order regarding generators with a counterparty receiving allowance allocations for industry assistance, CARB staff should use the most current data available for the amount of electricity and steam sold (i.e., 2013 data for the initial allocation and data from the prior calendar year for allocations made thereafter) to help ensure that allowance allocations accurately reflect current operating output and to avoid any inequitable shortfall to such generators. (PH 1)

Comment: 2013 Emissions Data Should Determine the Allowance Allocation Granted to Legacy Contract Generators for the 2013 and 2014 Transitional Period. CARB is proposing to use 2012 emissions data to calculate the allocation that will be granted to legacy contract generators for the 2013 and 2014 transitional period.[18] Given that the actual allocation will not occur until October 15, 2014, CARB should use 2013 emissions data, which will be reported and verified prior to the 2014 allocation date, to determine the amount of the allocation.

[18] See Appendix E: Proposed Regulation Order, Sections 95894(d)(1) and 95894(d)(2).

Using 2013 emissions data will more accurately represent the emissions for 2013 and 2014 because the information will be closer in time to the actual allocation in 2014. This is consistent with how CARB is proposing to determine the allocation for legacy contracts with industrial counterparties receiving a free allocation, which as IEP understands it, will use 2013 emissions data for determining the allocation granted in 2014.[19] Accordingly, IEP recommends using 2013 emissions data for determining the allocation for the transition assistance granted for 2013 and 2014. (IEPA 1)

Response: ARB staff worked with stakeholders to prepare 15-Day Modifications to the Regulation that provide an allocation of true-up allowances to legacy contract generators that may be used to meet a compliance obligation for the years 2013, 2014, and subsequent years, and that extends transition assistance through the second compliance period.

The legacy contracts that have been brought to ARB staff's attention have many different components, arrangements, and agreements between the parties. There is not a one-size-fits-all solution that will address all of the contract arrangements. Therefore, ARB staff developed a broad set of requirements that will capture and address most of the legacy contract issues. ARB staff has determined that the 2012 data year is the appropriate year to use in the calculation of an allowance allocation for legacy contract generators without an industrial counterparty because these data are the most current verified data available. Board direction was to provide transition assistance, not full coverage of an annual compliance obligation. Furthermore, using the 2012 data year provides ARB and legacy contract generators without an industrial counterparty with certainty of the total number of allowances that will be allocated.

One commenter notes the potential for an increase in dispatch of electricity from a legacy contract generator due to the declining cap, and the incentive that is created under the Cap-and-Trade Regulation to increase the dispatch of low emitting resources. This is not true in all cases and only true when the purchaser of the electricity also controls the dispatch. Further, providing full coverage of legacy contract generators' compliance obligations would provide a disincentive to renegotiate contracts.

One commenter requests the proposal for transition assistance be consistent and equivalent among all legacy contract generators, and to accomplish this, requests a modification be made to the use of true-up allowances, by including a true-up provision to the equation to determine the number of allowances to allocate to a legacy contract generator without an industrial counterparty. This suggestion is equivalent to the request to use the most current and verified data set available. Essentially, ARB staff already proposes to treat both sets of generators equitably, and does not agree a modification is necessary. The proposal is to allocate allowances through the second compliance period.

[19] See Appendix E: Proposed Regulation Order, Sections 95894(c)(1) and 95894(c)(2).

However, if a legacy contract generator has a contract with a counterparty identified to receive allowances under the industrial allocation, allowances will be transferred from the industrial counterparty to their legacy contract counter-party generator. The purpose of the allowance allocation to the industrial entity is due to the GHG cost exposure, and the possibility of resulting product leakage. However, due to the legacy contract, the industrial entity does not face that full GHG cost exposure, and therefore including the emissions due to the steam or electricity provided by a legacy contract generator in the calculation for transition assistance is not necessary. ARB staff will deduct the number of allowances from the industrial entity based on the steam and/or electricity emissions for the steam and/or electricity sold to the industrial entity under the legacy contract for the life of the legacy contract. To accomplish this it is necessary to refer to the use of current data, because the allowance allocation to the industrial party is based on current data, with a true-up provision included in the calculation.

ARB staff maintains that the preferred approach to addressing legacy contracts is for the parties to renegotiate the contract. This approach provides the correct incentive and facilitates the implementation of the program design to pass the GHG compliance cost down to the end-user of the electricity

Allowance Allocation Beyond First Compliance Period

B-3.10. Multiple comments: My name is Beth Vaughan, Executive Director of the California Cogeneration council. And I've appeared before you on this issue of legacy contracts. Within our membership, we have a number of combined heat and power projects between the thermal host and the third-party cogenerator. And these contracts do not have provisions to enable the recovery of GHG compliance costs.

The modified staff proposal providing transition assistance to the end of the second compliance period solves the problem for I believe the majority of the 20 eligible legacy contracts that have been identified by ARB staff. And I'm happy to say almost all of mine. It includes all but one of my member contracts. To put that into perspective, three years ago, when the draft regulation came out October 28th of 2010, I remember my dates too, not by the birth of my children. And at that time I believe we identified within our membership about twelve of these legacy contracts. When I appeared before you a year ago, we were down to six. And now we only have one where the regulation does not solve for them.

So I'd like to thank the ARB Board and members with whom I've met on this issue and all the staff who have been working very hard over a very long period of time for proposing this change in addressing what I believe is significant issue for those affected companies.

However, as I mentioned, the modified staff proposal does not solve for one of our facilities and this is Crockett Cogen. This is because the thermal contract between Crockett and C&H sugar extends beyond 2013. Crockett Cogen is the only facility on

ARB's list of 20 eligible generators in the unique situation where the industrial host meets the definition of energy intensive trade exposed entity but is not covered by the cap and trade regulation. In this case, C&H sugar refinery is not an industrial covered entity because it did not emit greater than 25,000 metric tons. This is solely because Crockett Cogen combusts natural gas it supplies all the thermal energy used in the production of the sugar, and it provides the steam that C&H uses to run its two steam turbines to produce on-site electricity. But for Crockett Cogen, C&H would be an industrial covered entity receiving an allocation of free allowances under the regulation.

If C&H emitted above the 25,000 metric tons threshold, it would receive the free allowances that could be transferred to Crockett Cogen as per the 45-day proposed amendment. Our recommendation is to make an exception for Crockett because of this unique situation and to provide transition assistance for the term of its legacy contract. (CACOGEN)

Comment: Good morning Chair Nichols and the Board members. My name is Dan Consie, I'm the Asset Manager for Crockett Cogeneration. We are 240 megawatt combined cycle cogeneration facility, and we supply the thermal load for the C&H Sugar Refinery in Crockett, California. We supply C&H with approximately two million MMBTU of steam annually. Were C&H to self-supply this steam, they may be facing a compliance obligation of approximately 135,000 metric tons annually. However, as Ms. Vaughn mentioned earlier, C&H is not a covered entity under the Cap and Trade Program. The entire compliance obligation associated with the thermal load is borne by Crockett Cogeneration. There is no mechanism in the thermal sales contract to pass through that cost of compliance to C&H. I'd like to thank the Board and the staff members for considering the issues that those of us with legacy contracts are facing. I also appreciate the modified staff proposal that just was released that extends transition assistance through the second compliance period for entities such as Crocket Cogen. However, as Ms. Vaughan said earlier, our thermal contract with C&H extends beyond the third compliance period. And therefore, I'm here to request transition assistance for Crockett Cogeneration through the remaining term of its thermal sales contract. Thank you. (CROCKETT)

Comment: Given the situation, we recommend that the ARB revise Section 95894(d)(2) to allocate allowances not just through the first compliance period but through the balance of the original term of the Non-Standard Contracts. As the board staff is aware, this change will only affect a very small number of projects. It will eliminate the inequity they face by not having any other options and we submit will have virtually no impact on the overall C&T program. (CSU 1)

Comment: Transition assistance should be provided to CHP QF generators with Legacy Contracts at least through the second compliance period (2015-2017). Indeed, prior to the release of CARB's July 2013 Discussion Draft of the Proposed Amendments, it was understood that CARB intended to grant relief through the duration of the Legacy Contracts. Specifically, in the public meeting of September 20, 2012, CARB staff explained that entities that signed contracts prior to January 1, 2007 and whose legacy contracts were not significantly amended after that date would be eligible for allocation, *and that "[a]llocation would end when the existing legacy contract ends or is significantly amended*."[20] Further, as discussed in the OLS Comments of August 2, 2013, earlier drafts of the Proposed Amendments and information provided at the May 1, 2013 CHP workshop also created an expectation that transition assistance allocated to Legacy Contract Generators would be provided until the earlier of the expiration of the Legacy Contract and the date of an amendment of the Legacy Contract, if any. However, like the July 15 Discussion Draft of the Proposed Amendments, the current draft limits transition assistance to 2013 and 2014, leaving OLS and similarly situated CHP QF generators without a means to recover their GHG Compliance Costs after 2014. (OLS 1)

Comment: CARB staff's shift in position, providing relief only until the end of 2014, appears to be based on an unrealistic expectation that counterparties will, in the future, be willing to amend Legacy Contracts. In its Initial Statement of Reasons, CARB staff states that limiting the transition assistance to the first compliance period "maintains the incentive for legacy contract generators to renegotiate while providing appropriate transition assistance for these generators in accordance with Board Resolution 12-33."[21] CARB staff also raises a concern that "many legacy contract generators have already renegotiated with counterparties in such a way that the generator may have received less than full compensation for GHG costs", and that providing a full allocation for the entire contract period for all legacy contract generators "would have the perverse result that those who renegotiated could have received less favorable treatment than those who did not renegotiate."[22] While OLS understands staff's concern that parties who renegotiated their contracts should not in effect be penalized for having done so, OLS emphasizes that renegotiation simply is not a possibility for OLS and certain similarly situated generators. OLS did not "hold out" in negotiations with SCE; rather OLS simply had and continues to have no leverage or trade-off to offer SCE. Thus, SCE had and continues to have no reason to renegotiate its contract in any manner that would provide relief to OLS. Thus, although CARB "believes that allowance allocation limited to the first compliance period is sufficient to provide transition assistance while simultaneously providing the parties additional time to renegotiate the contracts"[23], additional time for renegotiation is extremely unlikely to result in SCE agreeing to provide any relief to OLS. Once transition assistance expires following 2014, OLS will have no means to recover its GHG Compliance Costs.

As explained in the OLS Comments of August 2, 2013, the Chino PPA was amended many years prior to the passage of AB 32. As such, OLS should not be penalized because its power purchase agreement with SCE does not have a provision that would enable OLS' recovery of GHG Compliance Costs. Therefore, OLS believes that OLS and similarly situated CHP QF generators should be provided transition assistance for

[20] CARB September 20, 2012 Meeting Transcript, at p. 106, lines 10-16 (emphasis added); available at: http://www.arb.ca.gov/board/mt/2012/mt092012.pdf.

[21] Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms – Staff Report: Initial Statement of Reasons (Sept. 4, 2013) at p. 18

[22] Id.

[23] Id.

the duration of their Legacy Contracts. However, in recognition of CARB's concern that providing a full allocation for the entire contract period for all Legacy Contract generators may create a disfavorable result for parties who did renegotiate their contracts, OLS proposes a compromise position: that transition assistance be provided through the second compliance period. To effect that proposal, OLS thus respectfully requests that Section 95894(d)(1) of the Proposed Amendments be revised to add calculations for the provision of allocations through the second compliance period (2015-2017). (OLS1)

Comment: The ARB Should Revise Section 95894 (d) (2) To Allocate Allowances Through The First Two Compliance Periods Of A Legacy Contract.

We strongly urge the ARB to continue with its allocation to Non-Standard QF Legacy Contract- holders for an additional compliance period, from 2015-2017, to provide sufficient time for renegotiation or, in the case in which a customer continues to refuse to renegotiate, time to retrofit or readjust operations for the inevitable high cost of compliance. By providing allowances to legacy contract holders for two compliance periods, the ARB limits the risk of these facilities shutting down and at the same time secures essential generation for the short term. The additional three years of recovery will give generators time to align operations to the substantial and inevitable hit to a facility's bottom line.

Moreover, extending the coverage for Legacy Contract Generators is consistent with the Board's direction to provide "transitional assistance." In the industrial sector, the ARB proposes to provide "transitional assistance" based on 100% allocation for the first two triennial compliance periods. As explained in the Initial Statement of Reasons for the September 4, 2013 Amendments: Staff proposed delaying the reduction in the assistance factor by one compliance period. The assistance factor will be maintained at 100% for all leakage risk classifications for the second compliance period if the proposed amendments are adopted... Shifting the assistance factor decline by one compliance period does not change the program cap or its annual decline. Staff proposed making this change in order to ensure consumers are not negatively impacted by the Program *while providing time for industry to transition to lower-carbon production methods*.

Similarly, Legacy Contract Generators need additional time to renegotiate their contracts or otherwise adjust to the program in order to avoid risks of shutting down and negatively impacting electricity markets, particularly in Southern California. The ARB should treat the transitional assistance for Legacy Contract Generators consistently with how it has structured transitional assistance for industrial sources, and provide complete coverage through the first two triennial compliance periods. (WM 1)

Comment: We offer one minor comment: In another section of the Proposed Amendments generally concerning the timing and mechanics for allocation (section 95870, "Disposition of Allowances"), it appears that an oversight was made and this section still contemplates that, in all cases, legacy contract allocations would only be provided for 2013 and 2014 and not for the duration of the contract, as is the case where the counterparty receives an allocation for industrial assistance. Consistent with the intention stated by CARB in the quotation from the ISOR above, this section should be amended to reflect that, where the legacy contract counterparty will receive an allocation for industrial assistance, the allocation to the generator will be provided by October 15 of each year, as follows:

§ 95870. Disposition of Allowances.

(g) Allocation to Legacy Contract Generators. Allowances will be allocated to legacy contract generators for 2013 and 2014 for transition assistance in accordance with section 95894. The Executive Officer will transfer allowance allocations into each eligible generator's limited exemption holding account by October 15, 2014 for eligible Legacy Contract Emissions for calendar years 2013 and 2014 pursuant to the methodology set forth in section 95894 and by October 15 of each subsequent year if the generator qualifies for an allocation pursuant to section 95894(c). (CALPINE 1)

Comment: Extending the Transition Assistance Through 2017 is Appropriate Because Little Incentive Remains for Renegotiation. In the Proposed Amendments, CARB indicates that its preferred approach for addressing legacy contracts is to let renegotiation between counterparties occur. While IEP agrees that the proposal to subtract allowances from the industrial counterparties receiving a free allocation and provide those allowances to the legacy contract generators may create an incentive for renegotiation among these counterparties; IEP is not convinced that limiting the transition assistance to the 2013-2014 time period for the remaining subset of legacy contract generators, as originally proposed, creates any new incentive to renegotiate; nor does it provide appropriate transition assistance for these generators in accordance with Board Resolution 12-33. Where the counterparty is 1) an IOU; 2) a POU; 3) a marketer; or 4) an industrial entity not receiving an allocation, no incentive exists to renegotiate.

There is no reason for any of the counterparties listed above to renegotiate with the legacy contract generators and begin paying for the GHG compliance costs that they currently receive for free. Meanwhile legacy contract holders are facing the real world implications of unrecoverable costs associated with their generation assets which lead to downgraded credit ratings, inability to finance debt, etc. As a result, it is very important that CARB's proposal to provide transition assistance through 2017 is adopted by the Board. Extending the sunset date for transition assistance from 2014 to 2017 helps tremendously generators subject to a legacy contract that by definition cannot recover the costs associated with greenhouse gas compliance. (IEPA 1)

Comment: Edit to proposed amendments on legacy contract generator allocations. Per our conversation, not in the new section dealing specifically with legacy contracts (section 95894, "Allocation to Legacy Contract Generators for Transition Assistance"), but in another section addressing the timing and mechanics for allocation more generally (section 95870, "Disposition of Allowances"), there appears to be an oversight in that the text still contemplates that, in all cases, legacy contract allocations would only be provided for 2013 and 2014 and not for the duration of the contract, as is the case where the counterparty receives an allocation for industrial assistance under the proposed amendments.

Recommendation: Thus, I think we should propose the following minor edits to that section, to make it consistent with the new legacy contract generator section:
§ 95870. Disposition of Allowances.
…
(g) Allocation to Legacy Contract Generators. Allowances will be allocated to legacy contract generators for 2013 and 2014 for transition assistance <u>in accordance with section 95894</u>. The Executive Officer will transfer allowance allocations into each eligible generator's limited exemption holding account by October 15, 2014 for eligible Legacy Contract Emissions <u>for calendar years 2013 and 2014</u> pursuant to the methodology set forth in section 95894 <u>and by October 15 of each subsequent year if the generator qualifies for an allocation pursuant to section 95894(c)</u>. (Calpine 3)

Response: Thank you for the support. Legacy contracts have various arrangements between the parties and there is not a one-size-fits-all solution to the legacy contract issue. The proposal ARB staff put forward to address legacy contracts, including the modified staff proposal, addresses most, but not all of the contracts. In addition to the effect of the cap-decline factor, some generators will experience an uncovered portion of a compliance obligation due to the contract terms. One commenter requests an exception be included in the regulation, specifically to apply to a specific generator. According to the design of the program, the counterparty should be experiencing the cost of the GHG emissions that results from the production of their product. If the counterparty were operating the cogeneration facility then they would be experiencing this cost. ARB staff does not agree additional language is necessary at this time to address this one contract. The 15-Day Modifications to allocate allowances through the second compliance period allow for additional time for generators to continue to discuss renegotiation with their counterparties. The additional allowances could be used by generators to incentivize counterparties to opt into the Cap-and-Trade Program. ARB staff continues to support these renegotiation efforts and is dedicated to supporting generators and their counterparties in determining the most appropriate approach to allocating the cost of compliance to the end-user of the steam and electricity.

The 15-Day Modifications to the Regulation extend the allowance allocation through the second compliance period and meet the requirements of the Board direction to provide transition assistance to legacy contract generators. The Board direction was not to provide full coverage of the compliance obligation. Providing an allowance allocation equivalent to a compliance obligation does not incentivize a reduction in emissions. ARB staff's preferred approach is for contract renegotiation, which results in the ability for the pass through of the compliance obligation, and achieves the desired outcome.

One commenter suggests continuing the allowance allocation once the contract has been renegotiated, to provide an incentive to renegotiate. ARB staff agrees with this approach and included modifications within the 15-Day Modifications which will allow the generator to keep its allowances even if subsequently the contract is renegotiated.

Avoiding an Emissions Obligation through the Second Compliance Period as an Alternative to Allowance Allocation through Second Compliance Period

B-3.11. Comment: If the ARB does not provide transitional assistance through the second compliance period, then it should allow Legacy Contract Generators to reduce their emissions below 25,000 MTCO2(e) for the entire second triennial compliance period and thereby avoid an emissions obligation for this period. As currently structured, Section 95853(a) would apply a compliance obligation to the second triennial compliance period even if emissions are below 25,000 MTCO2(e) each year in the second compliance period. A limited exemption from this provision is necessary to avoid the risks of Legacy Contract Generators shutting down during the second compliance period. This proposal would provide Legacy Contract Generators with greater flexibility in meeting the program's requirements and fulfills the Board's direction to provide "transitional assistance" to Legacy Contract Generators. To implement this recommendation, the ARB should revise Section 95853(a) as follows: § 95853. Calculation of Covered Entity's Triennial Compliance Obligation. (a) A covered entity that exceeds the threshold in section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions with a compliance obligation that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131of MRR from all data years of the compliance period. (f) <u>Withstanding section 95853 (a) A covered entity that receives transitional assistance pursuant to Section 95894 for the first compliance period will not be subject to a triennial compliance obligation in the second compliance period if its emissions levels do not exceed the threshold specified in section 95812 in any of three data years during the second triennial compliance period.</u> (WM 1)

Response: ARB staff does not agree with this proposal because it does not provide an incentive to renegotiate the legacy contract. This proposal could incentivize generators to reduce electricity output during this period, which could result in inadequate electricity supply. Some legacy contract generators are contractually obligated to provide a certain amount of electricity and steam, so the proposed modification would only apply to a subset of generators, and would not apply to generators already emitting well above the 25,000 metric ton CO_2e threshold. Additionally, there are some legacy contracts where the output is controlled by the counterparty, which further limits the effectiveness of this proposed alternative.

Allowance Allocation for 2013 and 2014 Only

B-3.12. Comment: We support staff's *original* proposal to end free allowance allocation to legacy contract generators after the first compliance period. Board Resolution 12-33 directed staff to include appropriate transition assistance for the handful of legacy contract generators that have been unable to renegotiate their contracts following the passage of AB 32 to account for carbon costs.

Under a legacy contract arrangement, compliance costs cannot be reasonably passed through to the purchaser of electricity, which negates the carbon price signal created by the cap-and- trade program to encourage emission reductions. By establishing a clear cutoff point for transition assistance, staff's initial approach was responsive to the Board's direction while sending the appropriate incentive for those outstanding contract negotiations to conclude.

We oppose, however, staff's new proposal to extend transition assistance for legacy contract generators though the second compliance period (consistent with our opposition to staff's proposal to extend transition assistance for the industrial sector, as outlined above). We ask the Board to adopt staff's original proposal and cut-off transition assistance to legacy contract generators after the first compliance period to encourage renegotiation and ensure a carbon price is passed through to electricity purchasers to encourage emission reductions. (NRDC 2)

Response: The purpose of extending the transition assistance is to be consistent with transition assistance provided to other sectors within the Regulation, and to maintain a reliable electricity supply to Californians. ARB staff has always maintained that renegotiation of a contract between the parties is preferable over allowance allocation. The proposal to extend allowance allocation through the second compliance period will allow for additional time for the continued renegotiation of the remaining legacy contracts.

Correct References to Subsections

B-3.13. Multiple Comments: Section 95856(h)(3) should be revised to reflect the new true-up provisions that would be provided in Section 95894 for Legacy Contracts. Section 95856(h)(3) provides a limited exemption from the vintage rules for allowances that have been allocated pursuant to certain Cap-and-Trade provisions. However, the current proposed amendment of Section 95856(h)(3) would not include Sections 95894(c)(1), 95894(c)(2), and 95894(d)(2) in the list allowance allocation Sections.

The entities described in 95894(c)(1), 95894(c)(2), and 95894(d)(2) are entities that qualify for a true-up under Section 95894. We propose that the ARB amend this Section 95894 to make these entities eligible to use 2015 vintage allowances for a 2013 or 2014 emissions year compliance obligation prior to 2015 for compliance. WM and Wheelabrator Norwalk recommends adding these three Sections to the list in Section 95856(h)(3). Corresponding changes should also be made in Section 95856(h)(1)(D) and 95856(h)(2)(D). These changes are necessary to clarify that entities receiving "true-up" allowances can fulfill their compliance obligation with allowances "allocated immediately before the current surrender deadline. (WM 2)

Comment: 2015 Vintage Allowances Allocated to Legacy Contract Generators for 2013 and 2014 Should be Eligible for Use Prior to 2015. CARB's Proposed Amendments seem to allow 2015 vintage allowances, allocated to legacy contract generators for 2013 and 2014 to be eligible for use prior to 2015.[24] Specifically, staff proposes to allow "facilities to use up to the amount of true-up allowances provided for compliance obligation two years prior to the vintage of the allowances provided by the true-up."[25] However, there are some inconsistencies in the actual language in the Proposed Regulation Order that need to be corrected in order to ensure that entities that are eligible to use 2015 vintage allowances in this manner, are included.

Specifically, Section 95856(h)(3) indicates: "An entity that is not eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1), cannot use the current calendar year's vintage allowances or allowances allocated just before the current surrender deadline to meet the timely surrender of compliance instrument requirements in section 95856."[26]

In Section 95856(h)(3) above, it seems that CARB may have unintentionally excluded sections 95894(c)(1), 95894(c)(2), and 95894(d)(2) from the list. The entities described in 95894(c)(1), 95894(c)(2), and 95894(d)(2) are entities that qualify for a true-up and thus should be eligible to use 2015 vintage allowances prior to 2015 for compliance.

IEP recommends adding these three Sections to the list as described in Section 95856(h)(3). Corresponding changes should also be made in Section 95856(h)(1)(D) and 95856(h)(2)(D). All of these changes are necessary to clarify that entities receiving "true-up" allowances can fulfill their compliance obligation with allowances "allocated immediately before the current surrender deadline."[27] It is critical that generators have these allowances available for their use in demonstrating compliance during the first compliance period.

> **Recommendation:** Proposed Regulatory Language for Section 95856. Timely Surrender of Compliance Instruments by a Covered Entity:

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[24] See Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Staff Report: Initial Statement of Reasons, Page 15, 16 & 142. Also See Appendix E: Proposed Regulation Order Section 95894(c) and Section 95894 (d).

[25] Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Staff Report: Initial Statement of Reasons, Page 15.

[26] Proposed Regulation Order, Section 95856(h)(3).

[27] Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Staff Report: Initial Statement of Reasons, Page 142.

(h)(1)(d) The current calendar year's vintage allowances and allowances allocated just before the annual surrender deadline up to the True-up allowance amount as determined in sections 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c)(1), 95894(c)(2), or 95894(d)(1), or 95894(d)(2) if an entity was eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c)(1), 95894(c)(2), or 95894(d)(1), or 95894(d)(2).

(h)(2)(D) The current calendar year's vintage allowances and allowances allocated just before the triennial surrender deadline up to the true-up allowance amount as determined in section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c)(1), 95894(c)(2), or 95894(d)(1), or 95894(d)(2) if an entity was eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c)(1), 95894(c)(2), or 95894(d)(1), or 95894(d)(2) .

(h)(1)(3) An entity that is not eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), 95894(c)(1), 95894(c)(2), or 95894(d)(1), or 95894(d)(2), cannot use the current calendar year's vintage allowances or allowances allocated just before the current surrender deadline to meet the timely surrender of compliance instrument requirements in section 95856. (IEPA 1)

Comment: Wildflower supports the Amendments to Section 95894. Wildflower believes that the amendments are a fair and balanced approach that will achieve the ARB's policy objectives of encouraging parties to renegotiate their legacy contracts, while at the same time, avoid facilities from shutting down due to their inability to pass through greenhouse gas compliance costs.

Section 95856(h)(3) should be revised to reflect the new true-up provisions that would be provided in Section 95894 for Legacy Contracts. Section 95856(h)(3) provides a limited exemption from the vintage rules for allowances that have been allocated pursuant to certain Cap-and-Trade provisions. As amended, Section 95856(h)(3) would not include Sections 95894(c)(l), 95894(c)(2), and 95894(d)(2) in the list allowance allocation Sections. The entities described in 95894(c)(l), 95894(c)(2), and 95894(d)(2) are entities that qualify for a true-up under Section 95894. As amended Section 95894 would make these entities eligible to use 2015 vintage allowances for a 2013 or 2014 emissions year compliance obligation. Thus, Section 95856(h)(3) should specifically reference Sections 95894(c)(l), 95894(c)(2) and 95894(d)(2). These changes are necessary to clarify that entities receiving "true-up" allowances can fulfill their compliance obligation with allowances "allocated immediately before the current surrender deadline."

Wildflower appreciates the ARB staff's efforts in working with the diverse group of parties affected by the Legacy Contract issue and looks forward to the successful resolution of this issue in the near future. (WILDFLOWER 1)

> **Response:** Thank you for the support. ARB staff agrees and made clarifications in response to the comments. The 15-Day Modifications included the additional references to section 95894 within sections 95856 so that all of the legacy contract generators that receive true-up allowances pursuant to section 95894 are able to use the allowances to meet a 2013, 2014, or subsequent year’s compliance obligation.

Contract Renegotiation

B-3.14. Comment: As a general matter, the direct allocation of allowances should be available to all otherwise eligible legacy contracts. Staff’s proposed Section 95894(a)(3)(C) would require an attestation that the operator of the legacy contract generator made a good faith effort, but was unable to renegotiate the legacy contract with the counterparty. The Staff states that the purpose of this new section is to ensure that the “operator has discussed the possibility of allocating these costs with the counterparty and has exhausted all other options to cover the cost of compliance.” Staff Report at p. 168.

Shell Energy supports the Staff’s revised (October 16, 2013) proposal to provide free allowances as Transition Assistance to non-industrial legacy contract holders. ARB should clarify, however, that the Transition Assistance will continue to be provided through the second compliance period (2017) even if the parties are able to renegotiate the legacy contract. This assurance is necessary in order to support contract renegotiation efforts. Parties to an otherwise eligible legacy contract should not be discouraged from renegotiating their contract based on the potential loss of a direct allocation of allowances. For this reason, proposed Section 95894(a)(3)(C) should be clarified to confirm that non-industrial legacy contract holders will receive Transition Assistance whether or not the parties are able to renegotiate the legacy contract. Shell Energy appreciates the opportunity to provide these comments on the Staff’s proposed amendments to the Cap and Trade Regulations. If Staff has any questions regarding these comments, Shell Energy would be pleased to discuss the concerns raised in these comments in greater detail. (SHELL1)

> **Response:** Thank you for the comment. In section 95894(f) of the 15-Day Modifications, ARB staff removed the requirement to prorate and return the allowances if the parties renegotiate. ARB staff agrees this will help to further incentivize contract renegotiation.

Definitions

B-3.15. Multiple Comments: The definition of "Legacy Contract" included in the Proposed Amendments should be revised to make clear that the exclusion of contracts "that gave rise to a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision D-10-12-035, with a privately owned utility as defined in Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU)" applies only to contracts for which a Legacy Amendment was actually executed. As explained above, OLS and a small number of other CHP facilities with Non-Standard QF Contracts were not in a position to execute, and therefore did not execute, the Legacy PPA Amendment. The text "gave rise to a Legacy PPA Amendment" may be too vague for such generators to obtain relief, because it is not clear what "gave rise to" is intended to cover.

> **Recommendation:** Therefore, OLS respectfully requests that CARB modify the Proposed Amendments by changing the second sentence in the definition of "Legacy Contract" as follows (additions are shown with double-underline and deletions with strikethrough):
>
> For purposes of this regulation, legacy contracts exclude contracts ~~that gave rise to~~ with respect to which a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision number D-10-12-035, was executed with a privately owned utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU). (OLS 1, WM 1)

Comment: The ARB Should Clarify Definitions Appropriate for Section 95894 To Make Plain That Transitional Assistance Is Available To Non-Standard Qualifying Facility Contracts. The proposed definition for "Legacy Contracts" includes contracts entered into between a QF and an Investment Owned Utility (IOU).[28] We concur and support this proposal. However, we believe some changes are needed to make clear the ARB's intent to provide transitional assistance to legacy contract holders who have no means of cost recovery.

1. First and foremost, we propose that the regulation include a definition of "Non-Standard QF Contract" to differentiate these contracts from standard offer contracts with standard short run avoided cost (SRAC) pricing provisions. A provision in the regulation granting specific definition for Non-Standard QF Contracts allows the ARB to clearly differentiate and treat differently the small group of generators with Non-Standard QF Contracts. We recommend the "Non-Standard QF Contract" definition provided below.

2. We are concerned with certain language in the definition of "Legacy Contract." The definition states "legacy contracts exclude contracts that *give rise to* a Legacy PPA

[28] The Proposed Definition states that "'Legacy Contract' means a written contract or tolling agreement, originally executed prior to September 1, 2006, *governing the sale of electricity* …. at a price, determined by either a fixed price or price formula, that does not provide for recovery of the costs associated with compliance with the regulation …"

Amendment …" [emphasis added]. We are concerned that the phrase "give rise to" is vague and open to misinterpretation. To correct this ambiguity, we recommend that the definition of "Legacy Contract" be changed to specifically include generators with Non-Standard QF Contracts that did not execute a Legacy PPA Amendment.

3. The regulation should include a definition of "Legacy PPA Amendment", as provided below, to make the meaning clear throughout the regulation.

4. We recommend changes in the definition of "Legacy Contract Emissions" with regard to the sentence "Legacy contract emissions do not include emissions *that are included in the calculations of cost* under the CPUC's Qualifying Facilities and Combined Heat and Power Program Settlement …" [emphasis added]

> **Recommendation:** We have provided the following specific language changes to the regulation. Please be aware that bolded underlined type indicates additions to language and language to be deleted is depicted with strikethrough type:
>
> "Non -Standard QF Contract" means a co tract that does not include standard pricing based on short-run avoided costs, but includes non-standard pricing provisions negotiated bilaterally between the parties to the contract.
>
> "Legacy PPA Amendment" means the performance standard amendment that was offered , under the Combined Heat and Power Program Settlement adopted by the California Public Utilities Commission (CPUC) by Decision number D-10-12-035, to combined heat and power qualifying facility (QF) generators that had existing QF contracts.
>
> "Legacy Contract" means a written contract or tolling agreement, originally executed prior to September 1, 2006, governing the sale of electricity and/or Legacy Contract Qualified Thermal Output at a price, determined by either a fixed price or price formula, that does not allow for recovery of the costs associated with compliance with this regulation; the originally executed contract or agreement must have remained in effect and must not have been amended since September 1, 2006 to change or affect the terms governing the California greenhouse gas emissions responsibility, price or amount of electricity or Legacy Qualified Thermal Output sold, or the expiration date. For purposes of this regulation, legacy contracts exclude contracts that give rise to a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement pursuant to CPUC Decision number D-10-12-035, with a privately owned utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU), but does not exclude generators with Non-Standard QF Contracts that did not execute a Legacy PPA Amendment. A legacy contract does not apply to opt-in covered entities. (WM 1)

Comment: IV. Equity, Fairness and Public Policy is Best Served by Granting Transitional Assistance.

As the ARB is aware, there is a small set of qualifying CHP facilities with Non-Standard Qualifying Facility (QF) contracts that are in need of a means to allow recovery of C&T compliance costs. Wheelabrator's Norwalk Energy (Norwalk) power plant is one such CHP facility. Facilities like Norwalk have Non-Standard QF Contracts that were entered into long before the legislature considered, or the public was in any way aware of, a potential C&T program in California.

These Non-Standard QF Contracts were bilaterally negotiated by the CHP facilities and the IOUs as far back as the 1980's, and included non-standard performance obligations in exchange for non-standard short run avoided cost (SRAC) pricing provisions. The existence of these non- standard performance obligations negates the ability to accept the standard legacy amendment under the CHP Program Settlement. These non-standard CHP facilities were financed and are operated based upon the non-standard pricing terms. These facilities also entered into obligations under additional agreements with third parties, including the State of California, based upon the non-standard pricing terms. Importantly, the Non-Standard QF Contracts do not address recovery of C&T compliance costs.

As part of the CHP Program Settlement, CHP facilities with standard legacy QF contracts were offered an amendment (the Legacy Amendment). The Legacy Amendment included short-run avoided cost (SRAC) pricing options for QFs paid under standard SRAC pricing, which under the legacy contacts are adjusted, from time to time, by the CPUC. Integrated into each standard SRAC pricing option were differing levels of recovery of C&T compliance costs.

Because Non-Standard QF Contract holders have non-standard SRAC pricing terms, not subject to adjustment by the CPUC from time to time, they were not in a position to execute the Legacy Amendment as a means of recovering C&T compliance costs. Executing a Legacy Amendment would have required Non-Standard Legacy QFs to forfeit their non-standard pricing terms that were the result of negotiations that required the CHP facility to forego certain benefits. In the case of Norwalk, accepting a Legacy Amendment would mean the facility operates at a loss.

In essence, the Legacy Amendment offered no means of recovery of C&T compliance costs for CHP facilities with Non-Standard QF Contract pricing. Non-Standard QF Contracts are not "addressed" by the CHP Program Settlement. Therefore, the regulatory amendments must be clarified to account for the unique circumstances of Non-Standard QF Contracts. (WM 1)

> **Response:** The definition of legacy contract does not include contracts that were executed between an IOU and a generator, if the contract was a result of an agreement pursuant to the Combined Heat and Power Program Settlement. The definition does include contracts between an IOU and a generator that are

considered Non-Standard QF Contracts. ARB staff agrees a modification to the definition will distinguish these two types of contracts. However, ARB staff does not agree with the modifications suggested by the commenters because there still could be some ambiguity as to which contracts the term applies to.

B-3.16. Comment: The ARB Should Clarify Definitions Appropriate for Section 95894 To Make Plain That Transitional Assistance Is Available To Non-Standard Qualifying Facility Contracts. Legacy Contract Emissions" means the emissions calculated, based on a positive or qualified positive emissions data verification statement issued pursuant to MRR, by the Legacy Contract Generator, that are a result of either electricity and/or Qualified Thermal Output sold to a Legacy Contract Counterparty, and calculated pursuant to section 95894 of this regulation. ~~Legacy contract emissions do not include emissions that are included in the calculation of cost under the CPUC's Qualifying Facilities and Combined Heat and Power Program Settlement pursuant to CPUC Decision number D-10-12-035.~~ (WM 1)

Response: ARB staff agrees with the commenter and made modifications to the term "Legacy Contract" in the 15-Day Modifications to address the commenter's concerns.

Other

B-3.17. Comment: CARB staff has undertaken significant efforts over the past many months to address several important aspects of the Regulation. In particular, CARB staff has worked closely with numerous stakeholders to address the legacy contracts issue, which threatens the continued viability of highly efficient electricity producing and combined heat and power ("CHP") facilities in California. While we continue to communicate with CARB staff and Members of the Board regarding this issue, at the date of this writing, neither CARB staff nor the Board has provided any further response on this matter since the Proposed Regulation Order was noticed on September 4, 2013. Thus, we are not providing further comments on the legacy contracts issue until CARB provides stakeholders with a response. (PH 1)

Response: Thank you for the comment.

B-4. Natural Gas Suppliers

General Support for Proposal

B-4.1. Multiple Comments: Greenlining strongly supports the overall framework for allocating natural gas sector allowances. Mirroring the precedent set by the electric sector framework, staff's proposal to allocate allowances on behalf of utility customers advances the principles of transparency and protecting low-income households while simultaneously offering opportunities to engage the public. Following in the footsteps of the electric sector will encourage further emissions reductions, preserve equity, and maintain consistency within the program. (GI)

Comment: We support ARB's proposal to allocate allowances from the natural gas sector for the benefit of natural gas customers. Like ARB's approach for allocating allowances from the electric sector, allocating allowances to the gas utilities on behalf of their customers ensures allowance value is used to benefit consumers and further the goals of AB 32. For example, the allowance value would be available to help customers reduce emissions through improved energy efficiency, cushion bill impacts, prevent adverse impacts on low-income customers, and help foster engagement and support for AB 32 broadly by providing a direct benefit to millions of customers.

The manner in which allowance value is provided to customers, however, is critical to achieve these objectives. The criteria identified by staff to guide the treatment of natural gas allowance allocation – encouraging GHG reductions, maintaining equity and consistency among sectors, advancing California's long-term climate and clean energy goals – all hinge on how allowance value is ultimately provided back to natural gas end users.[29] (NRDC 2)

Comment: EDF generally supports the hybrid approach to allocating allowances to the natural gas sector that staff proposes wherein utilities receive a free allocation of allowances and must consign some of those allowances to auction with the proceeds going to benefit rate payers subject to oversight from the Public Utilities Commission… We believe that this approach is consistent with the policy objectives outlined by staff at the natural gas allocation workshop, including encouraging GHG emission reductions, maintaining equity and consistency among participants and sectors under the cap, and ensuring consistency with California's long-term climate and clean energy goals.
As discussed in a prior joint letter to CARB, the approach has several benefits which include:

Providing allowance value to customers in a manner that rewards ongoing energy efficiency improvements and conservation to reduce GHG emissions
Both the consignment of some allowances to auction and the requirement that revenue is not returned to ratepayers volumetrically are important factors in incentivizing energy efficiency and GHG reductions. The requirement to consign some allowances to

[29] ARB, "Suppliers of Natural Gas: Background and Options," slide 12 (June 3, 2013), available at: http://www.arb.ca.gov/cc/capandtrade/meetings/060313/natural_gas_suppliers_workshop_presentation.p df.

auctions ensures that rates will reflect a carbon price signal. This signal is critical to incentivizing energy efficiency and GHG reductions. It is also critical that every cap-and-trade sector, including natural gas, sees a price signal in order to ensure a fully functioning market that efficiently invests in the most cost effective reductions. Similarly, returning revenue volumetrically to rate payers could reduce the incentive to conserve. When any revenue return to customers is independent of natural gas usage, the incentive to conserve is preserved even as the impacts of any rate increases are mitigated.

Managing customer bill impacts by providing transition assistance and reducing customer exposure to price volatility

The need to incentivize reductions through a price signal is appropriately balanced against the need to provide transition assistance to natural gas customers at the beginning of the program. We recognize that investments in energy efficiency that lead to GHG reductions do not necessarily occur overnight. Providing a gradual ramp up in carbon price can leave customers with the resources they need to make these investments early. Ensuring that utilities have a pool of free allowances to utilize directly for compliance can also ensure that they are buffered from any allowance price swings and can provide a consistent rate to customers that increasingly reflects the full price of carbon emissions.

Ensuring oversight, transparency, and accountability with regard to the allocation of allowance value to natural gas customers

As in the electricity sector, consigning allowances to auction ensures that there is a pool of revenue that can be used for the benefit of natural gas ratepayers. Since the Public Utility Commission will provide guidelines for the use of this revenue, there will be an opportunity for stakeholders to weigh in on the important decisions involved in utilizing the revenue to benefit rate payers while maintaining important incentives for reducing GHG emissions. Similarly, the revenue from consigned allowances provides an additional opportunity for protecting low- income rate payers who must spend a disproportionate amount of their income to meet their energy needs.

For all of these reasons EDF generally supports the hybrid free allocation / consignment approach for allowance distribution to the natural gas sector. (EDF 1)

Comment: PG&E supports the addition of Section 95893, which allocates allowances to natural gas suppliers on behalf of their customers. The proposal provides a fair allocation to natural gas suppliers, on behalf of their customers, with a balanced approach to the consignment of allocated allowances. The proposed allocation also establishes a framework for supporting the emission reduction goals of AB 32. (PGE 2)

Comment: NCPA supports the allocation of allowances to natural gas suppliers for the protection of natural gas ratepayers set forth in section 95893 of the Proposed Amendment. Natural gas customers will face rate increases associated with Program compliance costs, and as such, are the appropriate recipients of allowance revenues that are allocated to the natural gas suppliers. The proposed revisions properly recognize that the natural gas utility can place restrictions on the use of the allowance value, as long as the value is used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32. (NCPA 1)

Comment: Overall, the draft rules provide for a balanced allocation formula to the natural gas suppliers, on behalf of their customers. Through the proposed allocation formula in contained in section 95893, there will be a framework to develop a phased, balanced price signal. This will both help manage AB 32 customer costs as well as contribute to achieving the statewide greenhouse gas reductions goals. (JUC)

Comment: Regarding the new natural gas program, we also support the language which would provide free allowances for suppliers to sell on the market for natural gas. (ACC)

Comment: The City Long Beach supports the proposed amendments to exempt natural gas suppliers from the first compliance period by providing new allowances to this industry. Such changes will allow the City to ease its small natural gas customers into a price signal that will promote greater reductions in GHG emissions on a gradual and market basis. (LBC)

> **Response:** Thank you for the support.
>
> One commenter states that they support the proposed amendments to exempt natural gas suppliers from the first compliance period. ARB staff wishes to clarify that natural gas suppliers are not covered during the first compliance period, and that allowance allocation to natural gas utilities will begin in the second compliance period.

Support for Baseline Year

B-4.2. Multiple Comments: We would like to express support for the allocation of allowances, which will help mitigate and phase in the rate impact to our customers, the use of the 2011 base year for calculating the emissions cap. (GUG)

Comment: In addition, PG&E supports staff's proposal to use 2011 as the baseline year for the initial allocation of allowances. We appreciate ARB staffs effort to address our concerns through its recommended change to the baseline year. (PGE 2)

> **Response:** Thank you for the support.

Support for Non-Volumetric Revenue Return

B-4.3. Multiple Comments: We are greatly pleased to see ARB's recognition of the importance of returning allowance value to customers in a non-volumetric manner.

Volumetric return sends the wrong message by conveying to end users that they are to be rewarded for increased consumption. ARB has rightly chosen to maintain the carbon price signal and provide incentives to customers to take actions in furtherance of the state's climate goals. ARB's proposed action further recognizes the critical importance of protecting low-income consumers and households that spend a greater proportion of their incomes on basic goods and services such as natural gas service. Returning allowance value non-volumetrically supports expansion of the California Public Utilities Commission's historic Climate Dividend program, thereby mitigating the disproportionate impact of carbon pricing upon disadvantaged communities. (GI)

Comment: ARB should retain the requirement that allowance revenue be returned to gas utility customers in a non-volumetric manner.

We strongly support ARB's requirement that allowance revenue be returned to customers non- volumetrically – i.e., the more you consume does not equal the more you get.[30] A pure volumetric return of allowance value would undermine each of staff's objectives highlighted above, by: (1) blunting the incentive to reduce end use consumption (and associated GHG emissions) by tying usage directly to allowance value; (2) muting the carbon price signal in natural gas rates, which would raise equity issues relative to other sectors under the cap; and (3) dampening the incentive for businesses and consumers to find the most efficient and cost-effective means of reducing emissions, undermining California's ability to meet its long-term climate and clean energy goals.

Prohibiting a volumetric return of allowance value does not unlawfully infringe on the California Public Utilities Commission's authority to set customer rates.

The utilities argue that prohibiting a volumetric return of allowance value to natural gas customers, as staff proposes, unlawfully infringes on the California Public Utilities Commission's authority under the California Constitution to conduct ratemaking. We disagree.

First, it is not clear that setting broad policy parameters around the distribution of allowance value constitutes ratemaking. The California Constitution provides only that the "Commission fix rates."[31] The notion of exclusivity comes from case law, first elucidated by the court of appeal in City of Vernon.[32] Yet there, the court held that the Commission's exclusive authority covers rates the public utility earns for services furnished by the utility.[33] In contrast, the distribution of allowance revenue is not a service furnished by the utility; it is the creation of ARB's cap-and-trade program. Indeed, ARB could have elected to bypass the utilities altogether through other allocation methodologies.

[30] ARB, "Appendix E: Proposed Regulation Order," § 95893(d)(3), available at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappe.pdf.
[31] Cal. Const., art. XII, section 6.
[32] City of Vernon v. Southern Cal. Edison Co., 191 Cal.App.2d 378, 387 (App. 2 Dist. 1961).
[33] Id.

Yet even if the distribution of auction revenues were considered ratemaking, prohibiting a volumetric return does not unlawfully infringe upon the Commission's authority. The Commission does not have "exclusive jurisdictional control over any and all matters having any reference to the regulation and supervision of public utilities."[34] While the Commission's ratemaking authority may be exclusive over local governing entities, this has not been established where state-level statutory schemes are at issue.[35] Rather, courts have frequently found that the Commission does not have exclusive authority when its jurisdiction is concurrent with another comprehensive statutory scheme (such as AB 32) and where the Commission has yet to issue relevant competing regulations (as here).

Accordingly, cases involving competing state laws and accompanying agency jurisdictional conflicts have come to very different holdings than cases involving conflicts between local governments (which the utilities rely on).[36] In Leslie v. Superior Court, for instance, the Court held that state housing law and Commission rules and regulations were of equal dignity, especially where no overt conflicts existed from the Commission generating its own rules.[37] And in Orange County Air Pollution Control, the California Supreme Court held the Commission must share its jurisdiction where it is concurrent with another comprehensive, statutory scheme.[38]

The details of the revenue return methodologies for natural gas customers will ultimately be determined by the Commission, which we agree is the appropriate forum to address those issues. But ARB is on firm legal footing to maintain the prohibition of a pure volumetric return, which it has already determined is integral to the design of its overall allowance allocation framework for the natural gas sector. We urge ARB to maintain the current prohibition. (NRDC 2)

Comment: We strongly support the requirement that "any revenue returned to ratepayers must be done in a non-volumetric manner" Sec. 95893(d)(3). (EDF 1)

Response: Thank you for the support.

Opposition to Non-Volumetric Revenue Return

B-4.4. Multiple Comments: The Regulation should not include a prohibition on the return of the allowance value in a volumetric manner, as contemplated in section 95893(d)(3). Each natural gas supplier's governing body should be able to define the manner in which the allowance value is returned to its ratepayers, consistent with the

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[34] San Diego Gas & Electric Co. v. Sup. Ct., 920 P.2d 669, 700 (Cal. 1996), citing Vila v. Tahoe Southside Water Utility 233 Cal.App.2d 469, 477 (Cal. Ct. App. 1965)).

[35] See, e.g., Leslie v. Superior Court (1999) 73 C.A.4th 1042, 1049, 87 C.R.2d 313 and Orange County Air Pollution Control Dist. v. Public Util. Com., 4 Cal.3d 945, 954 (Cal. 1971).

[36] Compare City of Anaheim v. Pac. Bell Tel. Co., 119 Cal. App. 4th 838, 842-43 (Cal. Ct. App. 2004) and City of Vernon v. Southern Cal. Edison Co. 191 Cal.App.2d 378 (App. 2 Dist. 1961) with San Diego Gas & Electric Co. v. City of Carlsbad (1998) 64 Cal.App.4th 785, 797 (noting "the PUC has been held to have paramount jurisdiction in cases where it has exercised its authority, and its authority is pitted against that of a local government involving a matter of statewide concern. Where its jurisdiction conflicts with other than a local agency, commission directives have not been given such controlling effect.")

[37] Leslie v. Superior Court (1999) 73 C.A.4th 1042.

[38] Orange County Air Pollution Control Dist. v. Public Util. Com., 4 Cal.3d 945 (Cal. 1971).

goals of AB 32. If there are instances where the maximum benefit is achieved by returning the value on a volumetric basis, then the customer is best served by receiving the value in such a manner. There are a number of considerations that will be incorporated into the final distribution of allowance value to the end-use customer, and those considerations should be specifically tailored to serve the best interests of the customers of each individual natural gas utility. NCPA urges the Board to direct staff to draft 15-day revisions that would allow natural gas utilities to return the value in any manner they deem appropriate as long as the value “is used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32,” including returning the revenue to the ratepayers in a volumetric manner. (NCPA)

Comment: This new section (95893(d)(3)) proposes that any revenue return to ratepayers must be accomplished in a non-volumetric manner. The CPUC has exclusive jurisdiction over investor-owned utility ratemaking under Article XII of the California Constitution. Likewise, the governing boards of publicly owned utilities have jurisdiction over POU retail rate design. The natural gas utilities suggest that 95893(d)(3) be modified to parallel the electric utility language in 95892(d)(l) and 95892(d)(2) to avoid jurisdictional conflicts with other state and local agencies and request the following changes to section 95893(d)(3):

> **Recommendation:** Auction proceeds and allowance value obtained by a natural gas supplier shall be used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. ~~Any revenue returned-to ratepayers must be done in a non volumetric manner.~~ (PGE 1)

Comment: Section 95893(d)(3) specifies that any revenue returned to ratepayers must be done in a non-volumetric manner. The California Public Utilities Commission (CPUC) has exclusive jurisdiction over investor-owned utility ratemaking under Article XII of the California Constitution. In the 2010 Final Statement of Reasons, ARB recognizes the CPUC's jurisdiction for electric distribution utilities: "We acknowledge that electrical distribution utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the CPUC or by the governing bodies of publicly owned utilities, and that these entities have exclusive electricity ratemaking authority. Based on these grounds, we removed the language that the commenter refers to as 'fixed rebate' language."[39] PG&E therefore recommends that Section 95893(d)(3) be modified as follows to parallel the electric utility language in 95892(d)(3) to avoid jurisdictional conflicts with other state and local agencies:

> **Recommendation:** Auction proceeds and allowance value obtained by a natural gas supplier shall be used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. ~~Any revenue returned to ratepayers must be done in a non-volumetric manner.~~ (PGE 2)

[39] Page 1907 of ARB's 2010 Final Statement of Reasons: httr://www.arb.ca.gov/regact/201 0/capandtradel 0/f,or.pdf

Comment: 2. The Provisions on Auction Proceeds Should Eliminate Jurisdictional Conflict

Section 95893(d)(3) places limitations on the use of auction proceeds to be returned to the customers of natural gas suppliers. The new section proposes that any revenue return to gas utility ratepayers must be accomplished in a "non-volumetric manner." The California Public Utilities Commission (CPUC) has exclusive jurisdiction over ratemaking for investor-owned utility under the California Constitution. The governing boards of publicly-owned utilities (POU) have jurisdiction over POU natural gas retail rate design. Section 95893(d)(3) therefore creates a jurisdictional conflict with other state and local agencies. Section 95893(d)(3) should be modified as follows to parallel the electric distribution company language in Sections 95892(d)(1) and 95892(d)(2).

> **Recommendation:** Modification to Section 95893(d)(3) (Allocation to Natural Gas Suppliers for Protection of Natural Gas Ratepayers)
> Auction proceeds and allowance value obtained by a natural gas supplier shall be used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. ~~Any revenue returned to ratepayers must be done in a non-volumetric manner~~. (SEMPRA 2)
>
> **Response:** ARB staff intends for natural gas-related revenue return to be non-volumetric and believes it is appropriate to include this requirement in the Regulation. ARB staff maintains that prohibition of volumetric return is not in conflict with the rate-setting jurisdiction of the Public Utilities Commission (PUC) and local natural gas-related agencies. As noted by commenters supporting the prohibition of volumetric revenue return, ARB may place limits on allowance revenue use in order to maintain the goals of its own regulations, while respecting the PUC's broader ratemaking authority. The same jurisdiction which allows ARB to require revenue return to benefit ratepayers and to be consistent with the goals of AB 32 applies to the prohibition of volumetric revenue return.
>
> ARB staff contends that that volumetric revenue return is inconsistent with the goals of AB 32. As noted in the 2011 FSOR, "proper carbon pricing is the primary way in which the Cap-and-Trade Program achieves emissions reductions."[40] While removing the explicit description of volumetric electricity rate-setting, that FSOR noted that free allocation to electricity distribution utilities was made with the understanding that their "value would not be used to skew carbon pricing or reduce incentives for GHG reductions." Similarly, ARB staff intend that free allocation to natural gas utilities will not be used for a volumetric return of revenue, which would skew carbon pricing and reduce GHG reduction incentives.

[40] California Air Resources Board. Final Statement of Reasons. October 2011. Available at; http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

Consignment Requirement

B-4.5. Multiple Comments: Requiring that utilities consign allowances to auction on behalf of customers ensures that the carbon price signal is transparent and provides opportunities and incentives to invest allowance value in furtherance of additional GHG reductions. As such, we support an accelerated ramp up of the ratio of allowances consigned to auction as compared to the staff proposal. We recommend that the percentage consignment requirements start at 50% in 2015 and increase to 100% by 2020. This approach allows for a smooth yet meaningful increase in the amount of assistance and investment provided directly to end-use customers and in particular low-income households. (GI)

Comment: ARB should increase the consignment obligation on gas utilities to preserve a strong carbon price signal and maintain equity with other sectors under the cap.

The ability to submit allowances directly for compliance operates as an implicit volumetric return of allowance value (in that instance, the gas utility is using allowance value to prevent natural gas rates from rising to reflect the carbon price). We therefore recommend ARB increase the percent of emissions allowances that gas utilities must consign to auction, in order to ensure customers receive the benefits in a non-volumetric manner. Currently, staff proposes that utilities consign at least 25 percent of their allowances starting in 2015, ramping up 5% each year out to 2020.[41] We propose ARB increase the consignment obligation to 50% starting in 2015, and ramp up 10% each year out to 2020, such that gas utilities will consign all of their allowances by 2020.

Table 9-4: Percentage Consignment Requirements for Natural Gas Utilities by Year

Compliance Period	2			3		
Year	2015	2016	2017	2018	2019	2020
Percent Consigned	~~25~~ 50	~~30~~ 60	~~35~~ 70	~~40~~ 80	~~45~~ 90	~~50~~ 100

By preserving only part of the carbon price in natural gas rates, ARB's current proposal raises equity issues relative to the treatment of other fuels and sectors under the cap. Natural gas competes with gasoline, diesel and electricity for various applications, including space and water heating, transportation, and use in various appliances. ARB must be careful to avoid creating perverse incentives for investment decisions and emission reduction opportunities between and among sectors regulated under the cap. (NRDC 2)

Comment: However, although EDF supports the staff proposal to use a consignment auction, we urge CARB to consider whether the level of consignment should be increased from currently proposed escalating level – meaning natural gas utilities and rate payers receive less transition assistance in the early program years and a stronger

[41] Orange County Air Pollution Control Dist. v. Public Util. Com., 4 Cal.3d 945 (Cal. 1971).
21 ARB, "Appendix E: Proposed Regulation Order," Table 9-4, "Percentage Consignment Requirements for Natural Gas Utilities by Year," available at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappe.pdf.

carbon price signal in later years. As proposed, the ramp up starts at 25% and increases to 50% in 2020. As an alternative, EDF recommends CARB consider an escalating consignment that starts at 50% in 2015, escalating to full auction (100%) in 2020. (EDF 1)

> **Response:** ARB staff considered a variety of consignment requirements and decided to stay with the proposed 25% to 50% ramp from 2015 to 2020. There is no absolute method for identifying which consignment requirement provides the best balance between moderating the impact on ratepayers and maintaining incentives for GHG mitigation. The 25% to 50% increase in consignment was selected with the idea that, when the Cap-and-Trade Regulation is amended to provide for post-2020 allocation, the required minimum percent of consigned allowances will gradually continue to increase annually until it reaches 100%.

Opposition to Consignment

B-4.6. Multiple Comments: Food processors are the second largest industrial consumers of natural gas in the state. Managing operating costs is a priority and fuel costs represent a significant portion of those costs. Under the current ARB proposal requiring the scheduled consignment of allowances, food processors will likely face significant challenges to business operations and competiveness with businesses outside of California.

In a December 20, 2012 decision (D.11-02-019), the CPUC approved Pacific Gas and Electric's (PG&E) 2012-2014 Pipeline Safety Enhancement Plan (PSEP). The commission decision only covers PG&E's plan, though Sempra is also subject to similar inspection and replacement obligations in a separate proceeding.

The CPUC decision will impact food processors on two levels. First, the physical testing and possible repair or replacement of transmission or distribution pipelines has the potential to affect or disrupt seasonal operations. Secondly, the costs of the implementing the plan will affect all industrial gas users, as well as food processors, and those costs will be significant. Increases in transportation rates are estimated to be 14% to 40% which will remain throughout the implementation of the PSEP. ARB should recognize such dynamic costs increases, added to the costs of compliance, will impose an extreme hardship on industrial gas users in California.

ARB needs to consider other costs unrelated to Cap-and-Trade and the impacts of consigning allowances merely for the purpose of maintaining a carbon price in natural gas.

CLFP recommends ARB eliminate the consignment provision associated with the allowance allocations to natural gas suppliers and instead, provide the utilities with 100% of their allowances in 2015 with a small decline in free allowance through 2020. This proposal will keep costs manageable for all ratepayers, allowing for a phasing in of the carbon price to natural gas customers, while rewarding the industrial sector facilities, such as food processors, for taking early actions to reduce emissions. (CLFP 1)

Comment: ARB should provide 100% transition assistance to natural gas suppliers and public utility gas corporations without requiring consignment: ARB proposes to provide natural gas suppliers an allowance allocation based upon their 2011 compliance obligation and the cap decline factor. However, as noted by staff, the public utility gas corporations will be required to consign a portion of their allowances to the auction. While 2013 and 2014 will be 100%, starting in 2015, utilities must consign 25% of the allowances increasing by 5% each subsequent year.

As detailed in the utilities presentation at the July 17, 2013 workshop, natural gas customers in California have already spent over $2 billion on energy efficiency programs aimed at reducing natural gas use and associated greenhouse gas (GHG) emissions. More importantly, California's gas utilities' efforts have resulted in significant improvements and major reductions in emissions, the direct result being that California's natural gas sector is already below its 1990 GHG emissions levels years before the 2020 deadline.

ARB's proposal fails to take into account non-cap-and-trade related costs that will result in significant increases in the cost of natural gas. The California Public Utilities Commission (CPUC) is engaged in ongoing proceedings concerning the implementation of the Pipeline Safety Enhancement Plan (PSEP). The CPUC decision will impact California industries subject to the cap-and-trade as the repair or replacement of transmission or distribution pipelines is expected to increase the cost of natural gas through increases in transportation rates for natural gas. Current estimates place potential cost increases between 14% to 60% in order to pay for the implementation of the PSEP. ARB should recognize that such dynamic and burdensome costs will impose an extreme hardship on industrial gas users, threaten the economic recovery and put jobs at risk.

The AB 32 IG agrees with other stakeholder groups and recommends ARB eliminate the consignment provision associated with the allowance allocations to natural gas suppliers and instead, provide the utilities with 100% of their allowances in 2015 with a small decline in free allowances through 2020. This proposal will keep costs manageable for all ratepayers, allowing for a phasing in of the carbon price to natural gas customers, while rewarding the industrial sector facilities for taking early actions to reduce emissions. (AB32IG)

> **Response:** ARB staff declines to make the requested changes to natural gas supplier allowance allocation and consignment. ARB staff is aware of other factors affecting natural gas rates, particularly pipeline safety measures. Addressing climate change cannot wait until after other concerns such as these have been addressed. ARB staff believes the gradual annual increase of natural gas supplier consignment requirements is already sufficient to protect ratepayers while maintaining incentives for GHG mitigation.

Both commenters mention natural gas costs. Residential natural gas prices are currently about three fifths of their peak at $1.77 per therm in 2008.[42] Nevertheless, ARB staff recognizes that natural gas may be a particularly large cost for certain industries. To address this concern, facilities in these industries may choose to opt in to the Cap-and-Trade Program and petition ARB to receive allowances as emissions-intensive, trade-exposed industries, and/or they may participate in the rate-setting process at the PUC.

Competition among Natural Gas-Using Power Producers

B-4.7. Comment: Natural gas suppliers may also own, operate, and develop electric generation assets in competition with independent power producers (IPPs). Accordingly, any freely allocated allowances to these utilities on behalf of their natural gas interests, must be tracked, monitored, and accounted for by an appropriate regulatory agency such as the CPUC. CARB must be mindful that these allowances (or their intrinsic value) could be reattributed in a manner that inappropriately creates competitive advantage, an outcome that to date CARB has steadfastly opposed.

Going forward, the regulatory agencies should not delegate to the utilities the responsibility for managing how those allowances or their value are distributed. Rather, CARB and the California Public Utilities Commission (CPUC) should require proper oversight, and ensure that these allowances are fully tracked and monitored in terms of their use while subject to appropriate regulatory oversight. (IEPA 1)

Response: The proposed changes to the Regulation require natural gas suppliers to use allocated allowances for the benefit of ratepayers in a non-volumetric manner, and requires suppliers to report annually to ARB on how they are complying with this requirement. This requirement, as well any rate-related requirements imposed by the PUC, should ensure proper oversight of the appropriate use of allowance value for ratepayer benefit in compliance with the requirements of AB 32.

Distribution of Natural Gas Compliance Obligation

B-4.8. Comment: WPTF remains concerned that generators using natural gas could potentially be subject to double carbon costs – once for the direct compliance obligation resulting from GHG emissions associated with their generation and again via pass through of carbon costs in natural gas prices once natural gas suppliers become covered entities under the program in 2015.

CARB's approach of notifying gas suppliers of the GHG emissions of their customers who are also covered entities presumes that the natural gas suppliers will thus ensure that carbon costs are not included in the prices charged to those customers. Yet, there

[42] Energy Information Administration, "California Price of Natural Gas Delivered to Residential Consumers (Dollars per Thousand Cubic Feet)," available at http://tonto.eia.gov/dnav/ng/hist/n3010ca3m.htm.

is nothing in the regulation that explicitly prohibits natural gas suppliers from including carbon costs in those prices. Further, in response to stakeholder questions about monitoring and enforcing the ‘expectation’ that natural gas suppliers will not include carbon costs in natural gas prices to covered entity consumers, staff have suggested that this would be the responsibility of the CPUC. Again, we do not consider this response sufficient, since operators of interstate pipelines are subject to the jurisdiction of the Federal Energy Regulatory Commission—not the CPUC.

To address these concerns, WPTF recommends that CARB include an explicit provision in section 95893 that prohibits natural gas suppliers from including carbon charges in their gas charges to customers that are covered entities under the cap and trade regulation. Additionally, CARB should require that each natural gas supplier include information in its annual report on the “Use of Auction Proceeds and Allowance Value” on how it has ensured that it excluded customers that are covered entities from any natural gas related price increase due to carbon costs incurred under this program. (WPTF 1)

> **Response:** ARB staff declines to make the requested changes. Interstate pipelines are not subject to the Cap-and-Trade Regulation. Natural gas suppliers, as defined under section 95811(c) of the Regulation, include only investor-owned utilities, publicly owned utilities, and intrastate pipelines that distribute directly to end users. Over 85% of natural gas used in California is supplied by investor-owned utilities, whose pricing is regulated by PUC. ARB staff anticipates that other natural gas suppliers are likely to avoid charging covered entities for natural gas costs. Because all natural gas suppliers are required to report to ARB regarding their use of Cap-and-Trade Program allowance value, ARB staff will be able to monitor the use of allowance value.

Allocation Dependence on Mandatory Reporting

B-4.9. Multiple Comments: The proposed Section 95890(f) appears to permit ARB to withhold allowances from natural gas suppliers that fail to comply with the MRR regulations and would thereby potentially impose a "double" penalty on natural gas suppliers and their customers over and above the significant daily penalties already authorized under section 95107 of the MRR. Such allowance withholding also discriminates against entities that receive direct allocations by punishing these entities and not parties that have purchased allowances or are subject only to the reporting obligation and associated penalties.

The proposed Section 95890(f) could also potentially allow ARB to withhold significant quantities of allowances without any showing of wrongdoing by the natural gas supplier and would not limit the amount of allowances withheld to the alleged under-reporting. ARB should not be permitted to withhold allowances in excess of those attributable to the non-compliant report.

Recommendation: To resolve these issues, the Utilities propose the following changes to section 95890(f):

Section 95890(f) A natural gas supplier that is a covered entity shall be eligible for direct allocation of California GHG allowances if it has complied with <u>the</u> requirements of the MRR <u>by obtaining</u> ~~and has obtained~~ a positive or qualified positive emissions data verification statements for<u> its individual GHG MRR report in accordance with section 95103(1) and section 95103(1) for</u> the prior year pursuant to the MRR<u>. If a natural gas supplier submits an inaccurate data verification statement for its individual GHG MRR report, ARB may withhold direct allocation of allowances up to an amount equal to the unverified tons within the Assigned Emission Level for the non-compliant report until such time as the natural gas supplier has obtained a positive or qualified positive emissions data verification statement regarding the non-compliant report.</u>

Finally, if the withholding provision is intended to operate as a forfeiture of allowances, we request that ARB clarify how allowances withheld under section 95890(f) would be recirculated back into the marketplace to avoid a sudden increase in the cost of compliance instruments that could be caused by the forfeiture of a large quantity of allowances. (PGE 1)

Comment: One item we ask CARB to reconsider is on holding allowances which results in double penalty when in non-compliance with reporting requirement. We have in our written comments submitted some suggested language that would clarify the intent of holding only the amount of allowances that are out of the reporting compliance. (GUG)

Comment: The proposed Section 95890(f) appears to permit ARB to withhold allowances from natural gas suppliers that fail to comply with the MRR regulations and would thereby potentially impose a "double" penalty on natural gas suppliers and their customers over and above the significant daily penalties already authorized under section 95107 of the MRR. Such allowance withholding also discriminates against entities that receive direct allocations by punishing these entities and not parties that have purchased allowances or are subject only to the reporting obligation and associated penalties. This issue is compounded for combined utilities with electric and gas service due to the possibility under the current regulation of having an electric allocation withheld for an error in a natural gas report, and vice versa.

The proposed Section 95890(f) could also potentially allow ARB to withhold significant quantities of allowances without any showing of wrongdoing by the natural gas supplier and would not limit the amount of allowances withheld to the alleged under-reporting. ARB should not be permitted to withhold allowances in excess of those attributable to the non-compliant report.

To resolve these issues, PG&E proposes the following changes:

Recommendation: Section 95890(f) A natural gas supplier that is a covered entity shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of the MRR by obtaining ~~and has obtained a~~ positive or qualified positive emissions data verification statements for its individual GHG MRR report in accordance with section 95103(f) and section 95103(l) for the prior year pursuant to the MRR. If a natural gas supplier submits an inaccurate data verification statement for its individual GHG MRR report, ARB may withhold direct allocation of allowances up to an amount equal to the unverified tons within the Assigned Emission Level for the non-compliant report until such time as the natural gas supplier has obtained a positive or qualified positive emissions data verification statement regarding the non-compliant report.

In addition, ARB should detail how these withheld allowances would be recirculated back into the marketplace to avoid a sudden increase in the cost of compliance instruments. Finally, we encourage ARB to make conforming amendments to section 95890(b) addressing allowance withholding for electric distribution utilities as follows:

Recommendation: Section 95890(b) An electric distribution utility shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR by obtaining ~~and has obtained a~~ positive or qualified positive emissions data verification statements for its electric power entity reports (in accordance with §95112 and §95115) and retail electric transactions report (in accordance with §95111) for the prior year pursuant to MRR. If an electric distribution utility submits an inaccurate data verification statement for its electric generation power entity report or retail electric transactions report, ARB may withhold direct allocation of California GHG allowances up to an amount equal to the Assigned Emission Level(s)(AEL) attributable to the non-compliant report(s). (PGE 2)

Comment: I want to just echo also a point that the gas utility group representative made about withholding, the withholding provision in the regulation. This is an issue where for a late report or under-report of number of tons, a handful of tons perhaps, a utility could lose their entire allocation. It's not clear in the rule at all that wouldn't happen for even if it's gas report, perhaps for the electrification and vice versa. So we propose language that gas utility group mentioned as well in there our joint letter to provide some proportionality if you have a report that's late, you would withhold the allowances only for that. That's one issue. (PGE 3)

Response: ARB staff believes the existing Regulation as amended addresses these concerns in sufficient detail. As noted by the commenters, Section 95890 specifies that any entity covered under the Cap-and-Trade Regulation will only receive allowances if it has received a positive or qualified positive emissions data verification statement under MRR. If a single entity, such as a natural gas supplier, is also a covered entity in another category, such as an electrical distribution utility, then Section 95890 will apply to the two as separate entities.

Allowances that are not directly allocated will be auctioned pursuant to section 95870(i). ARB staff expects that natural gas utilities have the information necessary to report accurately. ARB staff believes that it is important for the integrity of the program that any free allocation of allowances be withheld until the entity provides either a positive or qualified positive emissions data verification statement.

Clarification Regarding Use of Allowance Value

B-4.10. Comment: Can you confirm our interpretation that subparagraph (a)(3), below, applies only to the revenues from the 25% of allowances that are required to be consigned in 2015 (with annual increases thereafter)?

§ 95893. Allocation to Natural Gas Distribution Utilities Suppliers for Protection of Natural Gas Ratepayers. (a)…
(3) Auction proceeds and allowance value obtained by a natural gas supplier shall be used exclusively for the benefit of retail ratepayers of each natural gas supplier, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers. Any revenue returned to ratepayers must be done in a non-volumetric manner. (RPGE)

Response: ARB staff believes the commenter intends to refer to 95893(d)(3). As stated within it, this section applies to all auction proceeds and allowance value obtained by natural gas suppliers, including proceeds received from allowances consigned to auction as well as those allowances deposited into a utility's compliance account.

B-5. Other Allowance Allocation Comments

B-5.1 Comment: Air Products Supports Advancing the Allowance Allocation Date and Expanding the Factors Included under the Annual Allowance True-up – Air Products supports the proposal to advance the distribution of allowance allocations to October 15th of each year and expanding the definition of the true-up allowance amount to include changes in benchmark, allocation methodology, cap adjustment and assistance factors. These changes ensure the proper allowance allocation adjustment is made, and made in time, to inform a covered entity's compliance instrument procurement strategy prior to the surrender deadline. (APC 1)

Response: Thank you for the support.

B-5.2. Comment: We recommend that the ARB support the application of CHP by providing full allowance assistance throughout the compliance periods for covered entities using CHP. (SOLAR)

Response: This comment is not within the scope of changes to the Regulation. However, the Regulation contains provisions that recognize and support the application of CHP. For example, eligible universities and public service facilities will receive allowances through 2020 to recognize their leadership in emissions reductions and energy efficiency, including the use of efficient CHP. The Regulation also contains provisions for the limited exemption of emissions from the production of qualified thermal output through 2020. This exemption will move the compliance obligation for CHP facilities that would fall below the Cap-and-Trade Program compliance threshold of 25,000 metric tons of CO_2e "but for" their installation of efficient CHP systems upstream to the natural gas supplier.

B-6. Other Product Based Benchmarks

Tissue Benchmark

B-6.1. Multiple Comments. CARB should not normalize the product benchmark for water absorbency and should instead elect to utilize one of the following options:

(1) Set the product benchmark at 90% of the weighted average emissions from the industrial sector that includes both LDC/CTEC and CTAD technology. This option would be consistent with the approach of having one product one benchmark for this industrial sector that does not differentiate by technology.

(2) Set the product benchmark at 1.27 allowances per air dried ton of tissue. 1.27 is determined by taking 1.14 divided by 90% to back out the greenhouse gas emission intensity of the best performing facility upon which the product benchmark of 1.14 was derived. This option would be consistent with the best-in-class approach, which is the emissions intensity of the most greenhouse gas-efficient California facility. (KC 1)

Comment: The Procter & Gamble Paper Products Company recognizes the considerable effort CARB has invested in compiling extensive and detailed data to develop the proposed amendment which is consistent with existing benchmark principles. We agree that water absorption capacity is the most important functional characteristic for tissue and towel products and believe that the proposed amendment for tissue manufacturing is analytically based, logical and fair for tissue facilities. For all of these reasons, we support CARB's proposed amendment to apply the Equivalent Factor (EF) and adjust tissue production by water absorbency capacity so that the benchmark is short tons of tissue that hold the same amount of water. We thank the Board and CARB staff for their work on updating the tissue product benchmark and for the opportunity to provide these comments on the tissue product benchmark revisions. (PG 1)

> **Response:** ARB staff worked with the stakeholders to review the proposed benchmark and proposed amended benchmarks as part of 15-Day Modifications. Please see the 15-day Modifications and associated "Appendix A: Additions and Amendments to Product-Based Benchmarks in the Cap-and-Trade Regulation."

Recycled Boxboard Benchmark

B-6.2. Comment: We are pleased with ARB staff decision to revise the benchmark for the Recycled Boxboard Manufacturing sector from 0.499 to 0.516. By incorporating an additional year in the benchmark calculation, the new benchmark is now a truer reflection of the greenhouse gas emissions from the boxboard process. As an energy-intensive, trade-exposed facility, the increase in the allocation from this benchmark will allow us to compete better in the marketplace. We face severe competition from China, North Korea, Mexico, and US facilities outside California, so this adjustment is very important to Graphic

Packaging International and its ability to maintain a manufacturing presence in California. (GPI)

Response: Thank you for the support.

B-6.3. Comment: I'm trying to abbreviate my comments here. There is one area of concern, and we're just seeking clarification as to the need to publish the efficiency benchmarks in the regulation. There are a number of single operators that will be setting some of those benchmarks in the regulation. And so we're concerned that this could -- this information could end up being provided to some of their competitors. But we will work with staff to get through this process as well. But overall, we are looking forward to working through the leakage analysis and the benchmarks. And we just appreciate the time that everybody has taken. Thank you very much.(ACC)

Response: When there is only a one Cap-and-Trade Program covered entity that produces a product in a given benchmark category, ARB staff uses product data from multiple years so that confidential business information from any particular year is not disclosed. When there are multiple covered entities whose product data are used to calculate a benchmark, the fact that multiple years' worth of historical data are used to calculate the benchmark serves to obscure any one year's production data from a competitor.

The data collected through the rulemaking process are treated in accordance with Title 17, California Code of Regulations (CCR), sections 91000 to 91022 and the California Public Records Act (Government Code Section 6250 et seq.). Trade secrets as defined in Government Code Section 6254.7 are not public records and therefore will not be released to the public, including competitors. The California Public Records Act provides that air pollution emissions data are always public records, even if the data come within the definition of trade secrets. On the other hand, ARB considers the information used to actually calculate emissions to be a trade secret.

B-6.4. Comment: Also want to thank staff for all the work they've been doing to adjust those benchmarks and make sure they really reflect what's accurate and appropriate for the industries covered. It's a huge task. They'll really had to get into the nitty gritty of these companies. And I'm hearing back there's some very good relationships being built, and I think it really is going to help us going forward. (CMTA 1)

Response: Thank you for the support.

Natural Gas Liquid Processing

B-6.5. Comment: Inergy's comments follow-up on prior comments regarding the definition of "product" and related terms. As a natural gas liquids processor, Inergy continues to recommend that "product", "product output", "production" and related terms be clearly defined to ensure that that natural gas processing operations have reasonable certainty as to how the Cap-and-Trade Regulation and the MRR may apply to them and that they are equitably treated under those regulations. While the proposed revisions to the Cap-and-Trade Regulation, including the proposed modifications to the benchmark for natural gas processing facilities, begin to address some of Inergy' s concerns, additional revisions are needed to the both the Cap-and-Trade Regulation and the MRR to clearly specify what "product", "product output", "production" and related terms mean for purposes of reporting and allowance calculations. Inergy is a natural gas liquids processor. It is Inergy's understanding that its allowances are to be calculated using the product output-based methodology. Inergy reiterates here the unique characteristics of natural gas processing facilities, to demonstrate why it is critically important to clearly define the terms used for inputs to reporting requirements and allowance calculations.

As a natural gas liquids processor, Inergy does not "produce" natural gas from underground sources. Rather, it processes, stores, or distributes or resells unfractionated gas liquids delivered by others, typically natural gas producers. After processing, natural gas generally is delivered by pipeline to a public utility, and liquids are shipped to customers by truck and rail. Inergy may also store gas and liquids for customers, and, from time-to-time, Inergy may purchase a "product" and resell it. Other natural gas liquids processors may undertake similar activities, or they may operate differently.

Given the potential range of activities that natural gas processing facilities may perform, it is critical that CARB clearly and precisely define "product", "product output", "production" and related terms for purposes of reporting requirements under the MRR and calculating allowances under the Cap-and-Trade Regulation. As currently drafted, the proposed revisions to the Cap-and-Trade Regulation, in Section 95891 and Appendix C, provide some guidance as to how to account for both gas and liquids under the product output-based methodology, but they do not define what constitutes "product," "production" or "product output" in the first instance. The proposed revisions to the MRR contain the same flaw (see, e.g., Proposed Amendments to the MRR, Appendix A to Staff Report, Section 95156(c)). Thus, it is not possible to know what "output" reported to CARB will be used by the Executive Officer to calculate allowances, as contemplated in product output-based allocation methodology set forth in Section 95891(b) of the proposed revised Cap-and-Trade Regulation (see, e.g., definition of "Oa,t-2").

In order to resolve this uncertainty, and to avoid the potential for disparate application of the product output-based allowance methodology to similarly situated natural gas liquids processing facilities, the terms "product", "product output," "production" and other relevant terms must be defined, both in the Cap-and-Trade Regulation and the MRR (INERGY).

> **Response:** ARB staff disagrees with this comment. A natural gas liquid fractionating facility that does not exceed the 25 million standard cubic feet per

day (MMscf/day) gas processing threshold will be allocated allowances using the natural gas liquid processing product-based benchmark. Natural gas processing facilities that exceed the 25 MMscf/day gas processing threshold will be allocated allowances using the onshore natural gas processing product-based benchmark.

Pursuant to 95156(c) of the amended MRR Regulation in effect January 1, 2014[43], the operator of a natural gas liquid fractionating facility must report the annual production of natural gas liquids. The Cap-and-Trade and MRR Regulations clearly define "fractionates," "fractionator," and "natural gas liquids." As a result, ARB staff does not believe the additions of the terms for "product", "product output" and "production" as they relate to natural gas fractionators are required. If necessary, ARB staff will develop guidance to provide increased clarity to reporters on the issue.

Beverage Sector

B-6.6. Comment: The following changes need to be made to correct two definitions in Appendix C New and Modified Product-Based Benchmarks staff report. On page 9 Table2: Proposed Product Definitions for Beverage Sector (NAICS 312120 and 312130)

Crystal is a brand and not an accurate description of the material. "Dry Color Concentrate" is a more accurate descripting of this product. Please change Crystal Color Concentrate "Dry Color Concentrate."

"Activin" is a brand name and not an accurate description of the material. The most accurate name of this product is "Grape Seed Extract." Please change Activin "Grape Seed Extract." (GALLO)

Response: ARB staff modified the definitions as part of the 15-day regulatory amendments to include the commenter's recommendations.

Dried and Dehydrated Food Manufacturing

B-6.7. Comment: A. The product benchmarks should be increased substantially for onion and garlic to more fully and accurately reflect the actual energy use and emissions associated with producing these products. (OLAM)

Response: ARB staff modified the product benchmarks for dehydrated flavors as part of the 15-day regulatory amendments. ARB staff worked with the commenter on providing data, which were used to modify the benchmarks.

B-6.8. Comment: CARB should publish the data and methods it used to develop its proposed garlic and onion product benchmarks. (OLAM)

[43] Available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-regulation.htm.

Response: ARB staff has released public reports detailing the development of product benchmarks in Appendix A: Product-based Benchmark Development. The actual data used in the calculation of benchmarks includes annual production and energy use data and are confidential business information that cannot be published.

Transportation Fuels

B-6.9. Comment: We note that the discussion draft proposes to amend the treatment of natural gas in regard to allowances, but does not address any amendments to the treatment of other transportation fuels. If no changes are made, then ARB would be creating serious inequities in treatment of fuel sectors. If these inequities are allowed to persist, they could result in distortions in the allowance market and adverse economic impacts to California. The Cap and Trade program should treat all forms of consumed energy (both gaseous and liquid) and energy markets equally. (WSPA 1)

Response: ARB staff is not considering amendments to the treatment of transportation fuels other than natural gas. The purpose of allocation to natural gas suppliers is to provide transition assistance to their customers. The PUC governs how the providers of most natural gas set their rates and how they use revenues. As a result, the State can require that the value of allowances allocated to these natural gas utilities be returned to customers. However, transportation fuel suppliers set their own prices without State intervention. As a result, whether or not transportation fuel suppliers received free allowances, the State could not prevent them from charging customers for the value of the allowances they need for compliance, thus creating a windfall profit.

B-7. Allocation to Public Wholesale Water Entities

B-7.1. Multiple Comments: The State Water Contractors (SWC) is a non-profit, mutual benefit corporation organized under the laws of the State of California, comprised of 27 public agencies holding contracts to purchase water delivered by the State Water Project (SWP). The hydropower operations of the SWP represent about 4 percent of the state-wide use of electricity which makes the SWP the single largest end user in California. Implementing AB 32 measures will have a significant impact on the customers of the SWP. Thus, the SWC has a vested interest in the ongoing development of regulations for implementing AB 32. SWC's public agency members are the beneficial users of the SWP, providing water for drinking, commercial, industrial, and agricultural purposes to a population of more than 25 million people and to over 750,000 acres of farmland throughout the San Francisco Bay Area, the Central Valley of California, and Southern California. The primary purpose of the SWP is to store and deliver water to the customers of the SWP, who pay all of its costs. A significant part of the SWP costs relate to electricity generated and purchased at wholesale for the ultimate purpose of pumping water to consumers across wide areas of the State.

Delivery of this water is vital to the health, welfare, and productivity of the State of California. But the ARB treated the SWP customers differently than the customers of the electric utilities. The difference results in the customers of the SWP incurring costs and risks that ARB mitigated for the electric utilities. That inequity led to the ARB Board Resolution 32-11 adopted in October, 2011. This proposal provides a means for ARB to address the inequities while furthering the State's GHG emission reduction goals. Water supply projects are an important means of achieving these goals given the significant energy use in the water sector. SWP investments will reduce GHG emissions with the additional statewide benefit of facilitating the integration of renewable power into the power grid. We are prepared to assist the ARB include this proposal into the amended Cap-and-Trade regulations.

The Department of Water Resources (DWR) and SWC have been working for nearly three years with ARB, other agencies within the Brown Administration and the Legislature to craft an appropriate accommodation to mitigate the cost burden of Cap-and-Trade electricity sector regulations on SWP customers. That cost burden arises because DWR is one of two wholesale water conveyance agencies, Metropolitan Water District of Southern California (MWD) is the other, whose water operations are covered by the Cap-and-Trade regulations. ARB mitigated this cost burden that was also borne by the customers of the electric utilities.

The SWP mission is to deliver water throughout the State of California. It participates in the power market solely to supply electric power to its pumps. All of the costs of this electric power are passed through to the SWP customers. DWR acquires power from the wholesale California power market and is a partner in a new gas-fired plant in California. DWR has in the past and retains its right to import energy into California. The wholesale energy acquired by DWR supplements SWP renewable power purchases and hydroelectric generation which supplies over 50% of the energy used by the SWP pumps.

The ARB allocated emission allowances to electric utilities sufficient to offset the Cap-and-Trade costs, direct and indirect, of all the power used to serve their customers. The direct costs arise for emission allowances that must be surrendered to ARB. The allowances are surrendered for carbon emitting resources operated within California or imported from outside California. Indirect costs arise from power that is purchased inside California in which the carbon adder is imbedded. The ARB allocated allowances to the electric utilities without regard to whether the utilities have a direct or indirect cost. The customers of the SWP and MWD have a similar direct and indirect cost burden under Cap-and-Trade. It is estimated these additional costs will exceed $220 million by 2020. Approximately 80% of the $220 million Cap-and-Trade cost burden falls into the indirect cost category. The balance is the direct costs DWR incurs for its gas-fired power plant. The customers of the SWP receive no mitigation of the Cap-and-Trade cost burden.

The amount of energy acquired by DWR varies considerably from year to year due to changes in the amount of water conveyed through the SWP. For administrative ease, CARB recommended using an approach that would not have to track yearly data and require end of year revisions. Following CARB's recommendation, DWR averaged five years of SWP data to eliminate the annual variations in the acquired energy values. DWR and SWC requested free allowances for DWR to mitigate the cost burden of acquiring higher cost energy and covering DWR's share of the gas-fired GHGs. The number of free allowances was based on the average GHG content. This is a methodology that is similar to what was applied to the electric utilities.

ARB's proposal is to make no allocation to DWR and mitigate none of the estimated $220 million Cap-and-Trade cost. The areas of disagreement with the ARB proposal are: DWR Should Not Get Any Allowances Because SWP Does Not have a Compliance Obligation (Direct Cost): ARB contends that DWR is not eligible for emission allowances because it does not have a compliance obligation. SWC response: This position is in sharp contrast with ARB granting emission allowances sufficient to cover all costs of the utilities. Further, ARB mitigated the cost burden of utilities that had no compliance obligation.

SWP Not Eligible for Allowances to Offset Indirect Costs (Power Purchased Within California): Relatedly, ARB contends that emission allowances should not be used to offset indirect costs of the SWP. SWC response: ARB allocated allowances to the electric utilities without regard to direct and indirect costs. In some cases, the allocation of allowances solely offset the indirect costs. SWP Would Use Auction Proceeds Solely for Customer Refunds: ARB contends that DWR will monetize all emission allowances and use the revenue to refund its customers. SWC response: DWR is transitioning with State energy and carbon policy and has already made investments in energy efficiency and renewable power. DWR has identified future investments that will also provide GHG emission reductions. Those investments will be made to offset the cost of implementing AB32 to the benefit of the customers of the SWP. ARB Cannot Direct Funds to DWR: ARB contends that it cannot provide funds directly to a state agency without an appropriation from the legislature. SWC response: True as that may be, no law prohibits the ARB from allocating allowances to DWR in the same way it allocates allowances to the electric utilities.

Methodology: The methodology ARB applied to determine the number of allowances for the electric utilities took their 2009 resource plans and reduced the number of allowances to reflect utilities' obligation to go from 20% to 33% renewables. That method is consistent with the utility obligations. SWC response: The DWR Director approved and adopted a Climate Action Plan that includes a renewable acquisition schedule in May 2012. That should be reflected in the methodology, not the utility obligations.

Attachment 1: Allocation of Emission Allowances Per DWR Climate Action Plan

Year	2013	2014	2015	2016	2017	2018	2019	2020
SWP Energy Average 2008-2012 (MWh)	7,400,000	7,400,000	7,400,000	7,400,000	7,400,000	7,400,000	7,400,000	7,400,000
Reid Gardner (MWh)	420,000	0	0	0	0	0	0	0
Lodi Energy Center (MWh)	225,000	225,000	225,000	225,000	225,000	225,000	225,000	225,000
DWR Owned and Purchased Hydropower (MWh)	4,575,000	4,575,000	4,575,000	4,575,000	4,575,000	4,575,000	4,554,000	4,443,000
Renewables: (MWh)	108,000	144,000	180,000	216,000	252,000	288,000	324,000	360,000
Net Load: Market Energy (MWh)	2,072,000	2,456,000	2,420,000	2,384,000	2,348,000	2,312,000	2,297,000	2,372,000
Coal Emission Factor (MT/MWh)	1.116	1.116	1.116	1.116	1.116	1.116	1.116	1.116
CCCT Emission Factor (MT/MWh)	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Unspec. Source Emission Factor (MT/MWh)	0.428	0.428	0.428	0.428	0.428	0.428	0.428	0.428

Calculation of Emissions

Net Load Market Energy	2,072,000	2,456,000	2,420,000	2,384,000	2,348,000	2,312,000	2,297,000	2,372,000
Emissions Burden (Metric ton)	1,441,036	1,136,668	1,121,260	1,105,852	1,090,444	1,075,036	1,068,616	1,100,716
Allocation to DWR (Allowances)			3,698,964	1,105,852	1,090,444	1,075,036	1,068,616	1,100,716

The SWC propose that CARB provide free GHG emission allowances to DWR that are sufficient to offset both the direct (compliance obligations) and indirect (power purchased within California) cost burden of the Cap-and-Trade program to the benefit of the SWP customers, consistent with the table above. (SWC 1)

Comment: This comment of the State Water Contractors proposes the following language for inclusion in a Board Resolution:

Whereas, in Resolution 11-32, the Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, during the initial implementation of the cap-and-trade program, potential amendments to the Regulation,. including but not limited to the following areas:

> Distribution of allowance value associated with cap-and-trade compliance costs from using electricity to supply water, and the expected ability of allowance allocation and other measures to adequately address the incidence of these costs equitably across regions of the State.

Furthermore, if allowance value is used for the benefit of water ratepayers, it is used consistent with State efforts to promote efficient use and supply of water and water conservation.

Whereas, on September 4, 2013, after substantial discussions with public wholesale water agencies, ARB released proposed amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, that included a definition of public wholesale water agency and a proposed allowance allocation to one of the two public wholesale water agencies.

Whereas, the Board finds that the proposed amendments only partially address the direct and indirect cost burdens, including compliance costs, incurred by the two wholesale public water agencies as a result of the cap-and-trade regulations.

Now, Therefore, Be It Resolved, that the Board directs the Executive Officer, to further amend the allowance allocation in the cap-and-trade regulation to include both public wholesale water agencies. Staff shall propose amendments that accurately and completely address the total cost burden of the two public wholesale water agencies that are covered entities under the cap-and- trade regulation. Staff shall meet and confer on the additional proposed amendments with the water agency stakeholders, and return to the Board with the proposed amendments during the next 15-day notice and comment period for the cap-and-trade regulation.

Be It Further Resolved, that the Board directs staff to provide allowances to the public wholesale water agencies that can be used to meet a direct and/or indirect compliance obligation. The Board directs staff to include a proviso that the public wholesale water agencies shall use monetized funds that they obtain from the sales of allowances for projects that reduce greenhouse gas emissions, including but not limited to water conservation, energy efficiency, renewable energy, and related water-energy nexus projects. (SWC 2)

Comment: I'm Tim Haines with the State Water Contractors. We are an association of water agencies that receive water from the DWR's State Water Project. We distribute that water to 25 million businesses and families throughout the state. 750,000 acres of agricultural land as well. The customers of the State Water Project pay all of the costs that are associated with delivering that water, and that includes the cost of cap and trade.

In 2011, the Board passed Resolution that directed the Executive Officer to work with the wholesale water agencies in order to be able to address inequities that arise as a result of using wholesale power to deliver power to move water throughout the state. In the ensuing three years, we made significant progress. What we've been able to demonstrate with the staff is that the Electric utilities do not, in fact, provide retail power to the pumps that we use.

We've also shown that the water customers of the State Water Project incur a similar cost as to the electric customers that was mitigated by the Air Resources Board and the allocation free allowances.

What we've also been able to do is demonstrate that the cost burden of the electric utilities is similarly diverse as it is to the State Water Project customers, some that exceed free allowances, do not have a surrender obligation is one example of a similarity. The State Water Project is estimated to incur about $20 million in cap and trade costs in 2013. We project that that cost will be on the order of about $220 million between now and the end of 2020.

In comments that were submitted by the Department of Water Resources yesterday, what they did was confirmed that they are actually buying emission allowances in the past. They will participate in the next carbon market. And they will continue to participate in the markets going into the future.

They've also found no prohibition from the Air Resources Board being able to allocate emission allowances to the State Water Project DWR. The Resolution -- there's a lot more work to be done. And what we like to be able to do is continue that through the amendment process. We've offered some more precise Resolution language that we have past along, have made it available. And what we'd be like to do is work with the Board and staff to reflect the progress that's been made in the resolution in order to be able to set the stage for being able to make future progress that we're hoping for. (SWC 3)

Comment: The Department of Water Resources (DWR) respectfully submits the following comments on the proposed amendments to the Cap and Trade Regulations. DWR commends the Air Resources Board (ARB) for developing the innovative Cap and

Trade program and its other actions to implement AB 32's goals for greenhouse gas reduction.

In December, 2011, the Board directed ARB staff to address impacts of the Cap and Trade program on DWR. This letter is intended to bring to your attention additional information relating to this topic. DWR would appreciate ARB's attention to this information in its consideration of pending amendments to the regulation.

DWR's mission is to manage the water resources of California in cooperation with other agencies, to benefit the State's people, and to protect, restore, and enhance the natural and human environments. DWR is charged with management of the State Water Project (SWP), the largest state-built, multi-purpose water project in the country. The SWP was designed and built to deliver water, control floods, generate power, provide recreational opportunities, and enhance habitats for fish and wildlife. DWR has contracts with 29 local water agencies for delivery of up to 4.2 million acre-feet of water per year. Water deliveries serve 24 million people and provide irrigation for 750,000 acres of farmland.

DWR operates the SWP pumping and generating facilities to (in order of importance) (1) provide for safety and flood control needs; (2) comply with environmental regulations; (3) meet water supply and delivery needs; (4) minimize cost of water deliveries; (5) provide support for the electricity grid for the California Independent System Operator during periods of stress; and (6) provide for recreational opportunities. All of DWR's power activities are conducted for the purpose of making water deliveries and to support the grid. DWR is uniquely well-situated to assist in integration of renewable energy because of the SWP's ability to use electricity in the off-peak hours.

SWP power costs have ranged from $350 million to $600 million annually over the last few years. Approximately 96 percent of the costs of the entire SWP, including power costs, are paid by the 29 local agencies which have long-term water supply contracts with DWR.

In order to mitigate the cost impact of Cap and Trade on the State Water Project, DWR seeks to have allowances allocated to it in the same manner as allowances are allocated to municipal utilities. In the December 2011 Resolution, ARB recognized that cost impacts to DWR should be mitigated. The most straightforward way to mitigate the costs DWR is to allocate monetizable allowances to DWR and require the resulting funds to be used to further AB 32 goals. The rationales offered in opposition to this proposal fail to stand up under examination.

Some background is helpful to explain DWR's position. DWR's statutory authority includes the power to construct and operate power plants and buy and sell electricity (including imported electricity). DWR's power portfolio consists of self-generated hydropower and market purchases. Typically, DWR needs to purchase electricity to augment its hydropower resources; the market purchases now reflect the higher prices due to the Cap and Trade regulation. DWR currently does not generate electricity (except hydropower) and in July 2013, ceased importing electricity under a long-term contract with a coal plant owner in Nevada. DWR has contractual rights to a portion of output from the combined-cycle power plant known as the Lodi Energy Center (LEC) and must either acquire GHG allowances for delivery to the owner, Northern California Power Agency (NCPA), or pay NCPA to acquire allowances to meet NCPA's compliance obligation for LEC. DWR is expressly named in the Cap and Trade regulation. DWR has an obligation under the mandatory reporting regulation to report under Mandatory Reporting Regulation, and specifically must report the load of the SWP, even if it has no reportable emissions.

DWR currently acquires allowances to meet part of its projected requirements for the LEC power plant, based on the projected compliance obligation. DWR anticipates continuing to purchase allowances based on projected need, and may also sell allowances purchased in excess of need.

Prior to the adoption of Cap and Trade, negotiations were conducted with the IOUs and POUs to develop the allowance allocation methodology and table of allocations among IOUs and POUs. DWR asks that the same allocation methodology be applied to DWR's circumstances. That methodology allocated allowances to the utilities based on their load/resource portfolio, not on their compliance obligations. Against that background, DWR would like to provide additional information on several issues.

First, DWR's current lack of a compliance obligation under the regulation does not preclude an allocation of allowances. DWR does not seek an allocation of allowances in order to meet a compliance obligation, but to mitigate the cost impact of Cap and Trade. Allowances are allocated to IOUs and POUs without regard to whether they have a compliance obligation. A municipal utility with a portfolio consisting of hydropower supplemented with in-state market power would have no compliance obligation, yet would still receive its allocated allowances under ARB's regulation. Making a compliance obligation a prerequisite for receiving allocated allowances might lead to inverse incentives contrary to the goals of Cap and Trade.

Another additional point to consider is whether cost relief should be provided for "indirect costs." This is related to the first point, because it suggests that allowances should be provided only for "direct" costs, meaning fulfilling a compliance obligation. This distinction was not made in providing allowances to the IOUs and POUs. In fact, indirect costs are the basis for cost relief. The IOUs and POUs are allocated allowances based in large part on their market purchases, not the direct cost of their compliance obligation. As recognized by the ARB in structuring this program, the IOU's and POU's market purchases are the best measure of the impact on the utilities' ratepayers. Another issue to consider is whether DWR's status as a State agency warrants a different treatment under the Cap and Trade regulation. DWR recognizes that disbursements from the Greenhouse Gas Fund must be accomplished in the State's budget, approved by the Legislature; however, the regulation currently provides for allocation of allowances to IOUs and POUs. DWR is seeking comparable treatment.

Finally, I would like to address DWR's status as a wholesale user of electricity. DWR transacts in the wholesale electricity market and does not purchase electricity from IOU's retail service program; however, the use of the electricity purchased is put to final use as the electricity is consumed by DWR's pumping plants. DWR is both the generator/purchaser and consumer of electricity. There is no rational distinction between the consumptive use of electricity for the SWP and the utilities' provision of electricity to their customers.

In conclusion, DWR requests ARB to reiterate its support for cost relief for DWR. DWR is prepared to continue working with ARB staff to develop language for an amendment which would grant DWR, as operator of the SWP, the same cost mitigation and associated responsibilities as held by the publicly owned utilities, including the requirement to use the money for AB 32 goals. Thank you for your consideration and commitment to these issues of interest to DWR. (DWR)

> **Response:** The State Water Contractors and DWR propose that allowances should be awarded to DWR. However, ARB staff understands that, except for 2013 emissions for electricity imported from the Reid Gardner generation facility, DWR will not have a direct compliance obligation. This means that DWR would have no use for allowances except to sell them and use the revenue. However, State revenue in general is subject to allocation by the Legislature as part of the budget process. This is true for revenue from allowances that are auctioned by ARB. Therefore, ARB cannot provide allowances to DWR as requested. If SWP and DWR seek a portion of allowance revenue, it is a matter for the Legislature, not ARB.
>
> Furthermore, ARB staff agrees that consumers of water are, and should be, treated differently than ratepayers of electric utilities. In particular, two significant complementary measures increase electric ratepayer costs in addition to, and to a greater degree than, GHG compliance costs. Unlike electric utilities, water agencies are not subject to the renewable portfolio standard, and do not face high costs of energy efficiency requirements, both of which costs are passed through to customers in electricity rates.
>
> With regard to SWC 2, we note that the proposal for Board resolution language does not address the proposed changes and no response is necessary.

B-7.2. Comment: The Metropolitan Water District of Southern California (Metropolitan) has reviewed the Air Resources Board’s (ARB) Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Proposed Amendments), which ARB released on September 4, 2013, and provides the following comments on this document.

As the nation’s largest provider of drinking water, Metropolitan distributes water from the Colorado River and Northern California to 26 member agencies (cities and water districts), and supplies more than one-half of the water used by nearly 19 million people in the 5200 square- mile coastal plain of Southern California. Metropolitan's mission is to provide its member agencies with adequate and reliable supplies of high quality water to meet present and future needs in an environmentally and economically responsible way. In order to bring Colorado River water to Southern California, Metropolitan directly imports wholesale electricity for the sole purpose of operating the electrical pumps on the Colorado River Aqueduct (CRA). Metropolitan also obtains a significant portion of its water from the State Water Project (SWP) and pays more than 70% of the energy costs that the SWP incurs.

Metropolitan has a significant financial and regulatory stake in the cap-and-trade regulations and, consequently, has actively participated in the formulation of those rules from the beginning of the ARB process. Since Metropolitan does not buy power in-state, it incurs cap-and-trade- related costs through the purchase of allowances to cover the emissions associated with its imported non-hydroelectric energy. Since the SWP does not presently import energy, most of the cap-and-trade-related costs that it incurs are the indirect costs associated with higher energy prices, and with the operation of the natural gas-fueled Lodi Energy Center.

In spite of the ARB resolutions instructing ARB staff to work with the water sector to mitigate AB 32 compliance costs and the numerous discussions between ARB staff and water sector representatives, the parties have been unable to agree upon specific regulatory language or an allocation methodology that adequately mitigates cost impacts on the ratepayers of wholesale water providers. While the latest amendments to the cap-and-trade regulations provide some cost mitigation to Metropolitan in the form of a small allocation of free allowances, the methodology for this allocation in the amended regulations is fundamentally flawed. In addition, the amended regulations provide no cost mitigation for the SWP.

Metropolitan appreciates the efforts made by ARB staff to address cost impacts on publicly-owned wholesale water utilities and their ratepayers. However, additional modifications to the existing regulations will be required in order to provide adequate and equitable cost mitigation. Metropolitan provides the specific recommendations included below. These recommendations stem from the over-arching need to provide comparable treatment to the customers of both Metropolitan and the SWP that ARB has provided to the customers of the Electric Distribution Utilities (EDUs). Metropolitan recognizes that ARB has chosen to deal with the wholesale water utilities through a separate process and is not requesting that ARB revisit the EDU allowance allocation process. Metropolitan is, however, requesting that ARB not impose burdens on the water utilities that it imposed on the EDUs without also bestowing comparable benefits.

1. Definition of "Public Wholesale Water Agency." As Metropolitan has consistently argued in its formal and informal comments to ARB, cost mitigation should clearly be provided to both Metropolitan and the SWP. As ARB implicitly recognized when it permitted the POUs to either monetize their free allowances <u>or</u> use them to meet their compliance obligation, both direct and indirect costs will be borne by a utility's ratepayers. Public agencies, including the POUs, Metropolitan, and the SWP, must

pass all of their costs along to their ratepayers in the form of rate increases, irrespective of how the costs are incurred. Thus, with respect to price mitigation, the costs of increased energy prices are indistinguishable from the costs of purchasing allowances to meet a compliance obligation.

Furthermore, when ARB allocated free allowances to EDUs, it did so for the benefit of the EDUs' ratepayers, stating that allowance value could be used for "rebates, customer bill relief, or to pay for GHG-reducing measures such as energy efficiency, renewable electricity generation, or other similar programs."(ISOR, 2010 Regulation) This rationale for the use of free allowances clearly contemplates that free allowances may be used by the EDUs to mitigate <u>any</u> cost impacts on ratepayers (direct or indirect). There is no equitable basis for utilizing a different standard for wholesale water agencies.

> **Recommendation:** Revise Section 95802(a)(287) to include Department of Water Resources in the definition as follows:
>
> "Public Wholesale Water Agency" means a covered entity that is owned and operated as a special district, as defined in Statutes of 1960, Ch. 209 (California Water Code appendix § 109)<u>, and a state agency acting pursuant to California Water Code sections 120 and 12931 et seq.,</u> that uses electricity to convey wholesale water supplies.

2. Distribution of Allowances to Public Wholesale Water Agencies. Consistent with the comments in section 1 above, it is inequitable to limit a Public Wholesale Water Agency's use of allowances to direct compliance costs. Such a limitation is inconsistent with the rationale upon which ARB relied when permitting POUs to either monetize free allowances to mitigate ratepayer impacts or use them to meet their compliance obligations:

"Most POUs own and operate their own generation and do not compete with independent generators in the way IOUs do. Because of this, allowances directly allocated to POUs may either be consigned for sale at the general quarterly auctions or used directly to meet their compliance obligations. If a POU decides to auction some of its allowances at the general auction, the same auction rules apply to the POUs as those described above for the IOUs." (ISOR, 2010 Regulation)

ARB should therefore modify its Proposed Amendments to give Public Wholesale Water Utilities the same flexibility that it has given EDUs in utilizing free allowances for the ultimate benefit of their ratepayers.

> **Recommendation:** Revise Section 95870(d)(2) as follows:
>
> Allocation to Public Wholesale Water Agencies. The Executive Officer will place an annual individual allocation in the <u>limited use holding account</u> of a public wholesale water agency on or before October 15, or the first business day

thereafter, of each calendar year from 2014-2019 for allocations from 2015-2020 annual allowance budgets. The Public Wholesale Water Agencies shall advise the Executive Officer of the amount of allowances needed to be moved from the limited use holding account to the compliance account, so the Executive Officer can conduct these transfers. The Public Wholesale Water Agency may monetize at auction, allowances that remain in the limited use holding account, after their compliance obligations have been met. The Public Wholesale Water Agencies shall use the moneys obtained from the allowances solely for projects that reduce greenhouse gas emissions. The Public Wholesale Water Agencies shall provide an annual report to the Executive Officer on their use of these moneys.

3. Specific Allocation of Allowances to Metropolitan. Because its need to purchase imported energy, and thereby obtain allowances, varies based on operational needs, Metropolitan provided historical data to ARB, including annual averages, in order to facilitate the calculation of its allowance allocation. However, in calculating the allocation reflected in Table 9-5 of Section 95895, ARB relied on factors other than Metropolitan's actual compliance costs.

ARB purports to allocate allowances to Metropolitan "in a manner similar to the allocation to EDUs" based on "the compliance burden on ratepayers," but, in actuality, it would impose upon Metropolitan the burdens it placed on EDUs without conferring any of the benefits. In calculating the free allowances to be distributed to the EDUs, ARB considered the compliance costs associated with California's Renewable Portfolio Standard (RPS) as one basis for providing an allocation. ARB then reduced the EDUs' allowance allocation in the out years based on the theory that the initial investment in renewable resources would reduce the future need for allowances.

Since it does not serve retail electric customers, Metropolitan does not have an RPS requirement. While it would therefore be inappropriate to provide Metropolitan with assistance in meeting a RPS requirement, it is also inequitable to use an RPS requirement to reduce Metropolitan's allowance allocation going forward. Furthermore, the EDUs' declining allocation is based at least in part on the declining cap. Applying the declining cap and factoring in a reduced need for allowances due to renewable energy procurement unfairly reduces Metropolitan's allowance allocation well below its anticipated compliance costs.

The table below contains a calculation of allowances that should be allocated to Metropolitan, consistent with the principles articulated herein. To the extent possible, Metropolitan has used the input categories that ARB utilized to calculate its proposed allocation.

Metropolitan Water District - Colorado River Aqueduct Cap and Trade Cost Burden Mitigation								
Year	2013	2014	2015	2016	2017	2018	2019	2020
MWD CRA Energy Use Total (MWh) - Average 2008-2012	1.795.257	1.795.257	1.795.257	1.795.257	1.795.257	1.795.257	1.795.257	1.795.257
MWD Large Hydroelectric Hoover and Parker Dams (MWh) - Average 2008-2012	1.301.308	1.301.308	1.301.308	1.301.308	1.301.308	1.247.085	1.247.085	1.247.085
MWD Unspecified within CA (MWh) - Average 2008-2012	168,937	168,937	168,937	168,937	168,937	168,937	168,937	168,937
Average Net Unspecified Energy to be Imported into California (MWh)	325.012	325.012	325.012	325.012	325.012	379.235	379.235	379.235
Natural Gas and Market Energy Emission Factor (MT/MWh)	0.4354	0.4354	0.4354	0.4354	0.4354	0.4354	0.4354	0.4354
Greenhouse Gas Associated with Unspecified, Imported Energy (MT)	141,510	141,510	141,510	141,510	141,510	165,119	165,119	165,119
Cap Decline Factor	0.981	0.963	0.944	0.925	0.907	0.888	0.869	0.851
Emissions for Cost Burden Mitigation (MT)	138,822	136,274	133,586	130,897	128,350	146,626	143,488	140,516
Energy Efficiency Credit	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908
Annual Allowance Value	142,730	140,182	137,494	134,805	132,258	150,534	147,396	144,424
Allowance Allocation to MWD			420,406	134,805	132,258	150,534	147,396	144,424

Recommendation: Replace the allocation in Table 9-5 of Section 95895 with the last line from the table above.

Metropolitan endorses the allocation methodology for the SWP provided in the comments of the California Department of Water Resources and the State Water Contractors. Metropolitan appreciates this opportunity to comment on the proposed amendments to the cap-and-trade regulations and is available to discuss its recommendations in greater detail. (MWD)

B-7.3. Comment: I'm Mark Parsons, Senior Deputy General Counsel, and I'm speaking on behalf of the Metropolitan Water District. Metropolitan is the nation's largest wholesale provider of drinking water. We distribute water from the Colorado River and the State Water Project to our 26 member agencies and supply the water used by more than half of the roughly 19 million people in the coastal plains of Southern California. As noted by Mr. Haines the wholesale water utilities have been before your Board a number of times to request the same sort of cost mitigation for their customers that you have given to the customers of the electric utilities. MWD appreciates the work of your Board and staff in addressing their issues and are heartened your stated intent in a draft Resolution to continue working with Metropolitan to further development methodology for our allowance allocation.

As this process moves forward, we request that you consider Metropolitan's unique attributes and circumstances in refining the allowance allocation calculation.
While the impact of AB 32 compliance costs are felt by all utilities customers, mitigating those costs for each utility requires a recognition of different resource mixes and regulatory requirements. As an example, Metropolitan obtains much of its energy from large federal hydroelectric projects under contracts that will continue for at least the next 50 years. By ignoring the fact that Metropolitan obtains the preponderance of its energy

from this emissions-free resource, the regulation as drafted under-allocates allowances to Metropolitan for its supplemental energy needs. Your Board has made accommodations for similarly situated utilities, and we request you do so for MWD. With respect to the State Water Project, Metropolitan pays more 70 percent of the project's energy cost and is very are concerned about the $220 million cost burden that the cap and trade regulation will impose. The fact that the cost burden imposed by the project primarily involves increased energy costs rather than the cost of purchasing allowances is not a valid basis for determining that the project should not receive any allocation for free allowances.

Every dollar that a publicly-owned water or electric utility pays for AB 32 compliance will ultimately be paid by an end-use utility customer. By denying the State Water Project allowances simply because it does not have an obligation to purchase and surrender them, the draft regulations would penalize the project and its customers solely because it does not import or generate energy.

This is contrary to the Board's stated purpose of freely allocating allowances to the electric utilities, which is to offset the rate impacts of the cap and trade regulation. Finally, MWD supports the written comments of the Department of Water Resources and the written and oral comments of the State Water Contractors as well as the draft Resolution circulated by Mr. Haines. Thank you. (MWD 3)

> **Response:** MWD is the only water agency that is expected to have a direct compliance obligation under this Regulation in 2014 and subsequent years. Pursuant to direction from the Board, ARB staff worked with MWD extensively in development of the 45-day language of the proposed amendments, and shared staff thinking regarding an appropriate methodology that would take into account both the similarities and differences between MWD and the EDUs.
>
> In Resolution 11-32 the Board stated that “[w]ater rates should create the appropriate incentives for water conservation, greenhouse gas efficient technologies, and the efficient supply and use of water;” and “[c]arbon pricing is an important function of the cap-and-trade regulation, and that it is equally important that if allowance value is used for the benefit of water ratepayers it is used consistent with State efforts to promote efficient use and supply of water and water conservation.”[44]
>
> Furthermore, ARB staff responded to similar comments on pages 1590 to 1595 of the 2011 FSOR the reasons why water agencies are treated differently than electric utilities. ARB staff notes that the overall allocation to the electric sector took into account the allowances needed for electricity used by water agencies for pumping water and other water processes. Since then, electric utilities have begun to mitigate costs borne by electric and water ratepayers by providing climate credits, or by keeping rates lower than they would have been through using allowances for the benefit of ratepayers. As directed by the Board, ARB

[44] http://www.arb.ca.gov/regact/2010/capandtrade10/res11-32.pdf

staff continued to work with water stakeholders to balance the need for a carbon price effect and potential additional mitigation of increased costs in the water sector. ARB staff amended the Regulation to provide allowances to MWD to cover a portion of MWD's compliance costs at a level that best strikes that balance without overcompensating citizens and businesses that pay electricity and water bills. ARB staff notes that if allowances were allocated to MWD to cover most of their compliance costs, but not to the many water agencies throughout the State that also face indirect compliance costs in electricity (and starting in 2015, in natural gas) used for pumping from wells and other water delivery and processing uses, then inequity would be introduced across the State for water users.

B-8. Refinery Allocation

General Support

B-8.1. Multiple Comments: Kern Oil & Refining Co. (Kern) supports the adoption of the 45-day regulatory package and generally supports the proposed amendments related to refinery benchmarking…

Kern believes that ARB's current proposal largely addresses Kern's previous concerns regarding competitive disadvantages and inequalities in refinery allocations. (KERN 1, KERN 2)

Comment: The Coalition for Fair and Equitable Allocation (Coalition) supports the adoption of the 45-day regulatory package and generally supports the proposed amendments specifically related to refinery benchmarking. (CFEA 2)

Comment: So I'm here today to support the fact that we were able to reach resolution on a number of issues, assistance factor, the establishment of an atypical benchmark, and actually the metrics for that atypical we certainly think satisfy what a small refinery is. (CFEA 4)

Comment: Kern appreciates and supports staff's proposal to use the complexity weighted barrel for refinery benchmarking, including the considerations for all the process units, off-site adjustments, and notably the establishment of a separate benchmark for atypical refineries. (KERN 3)

Comment: First of all, thank you for the hard work in getting out what you did. We've come a long way from where we were. We still have lots of questions. We appreciate you listening to both the grouping, the offsites, the peer benchmarking. The proposal doesn't address a few things that we talked about, and we'll follow up with those, but they aren't the subject of today. (CFEA 5)

Comment: I'd like to echo Jon's comments and let you know how much we appreciate all the work that has been done and the proposal. We have questions and want to understand how you arrived at what you did, but again, just want to echo how appreciative we are of the proposal. (KERN 4)

Comment: Thank you for taking a good hard look at CWB. (PHILLIPS 3)

Comment: We're a member of the small refinery coalition that Jon Costantino talked about earlier, so I will not repeat his statements, but I will echo his appreciation for the final outcome reached in the quest to be equitable to all parties. (PARAMOUNT 2)

> **Response:** Thank you for the support.

General Opposition

B-8.2. Comment: A benchmarking scenario where some refineries get all free allowances and some refineries must buy 25 percent of their allowance is opposed by the steel workers and will not get the GHG emissions down to the target the State has set. (USW 1)

> **Response:** ARB staff believes that using product-based benchmarks to provide free allowances is equitable and provides properly aligned incentives for emissions reductions. When applying product-based benchmarks, it is natural that more emissions efficient facilities will have more of their compliance obligation covered by freely allocated allowances compared to less efficient facilities. The gap between a refinery's compliance obligation and the number of free allowances that it receives is dictated by its emissions efficiency relative to the rest of the sector.

Complexity Weighted Barrels v. Carbon Dioxide Weighted Tonnes

B-8.3. Multiple Comments: Kern strongly supports Staff's proposal to utilize Solomon's CWB allocation methodology for the refinery sector. The CWB is preferable to the previously considered Carbon Weighted Tonne (CWT) methodology because California refineries are more akin to worldwide refineries as opposed to European refineries, as illustrated by the methodologies' correlation factors(1).[45] (KERN 1)

Comment: PHILLIPS 66 supports the use of the Complexity-Weighted Barrel (CWB) approach to refinery benchmarking. (PHILLIPS 1)

Comment: WSPA strongly supports ARB's proposed change to Complexity Weighted Barrel (CWB). (WSPA 1)[46]

Comment: A key change was to propose the use of the Complexity Weighted Barrel (CWB) instead of the Complexity Weighted Ton (CWT) index that was used in Europe. WSPA strongly supports that change because the CWB methodology is appropriate for facilities in California because they measure throughput(s) in barrels rather than tons. (WSPA 2)

Comment: We greatly appreciate ARB's proposal to use Complexity Weighted Barrels (CWB) as the basis for refinery benchmarking instead of CO2 Weighted Tonnes (CWT). (CHEVRON 1)

Comment: First, we support staff's proposal to adopt the complexity weighted barrel methodology, inclusive of the adjustments for off sites, non-crude sensible heat, as well as the non-energy utilities. (LTC 2)

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[45] Workshop on Refinery Allocation under Cap-and-Trade, October 7, 2013, Staff Presentation ("October 7, 2013, Staff Presentation), pp. 8-12; Cap and Trade Workshop on Refineries and Related Industries, August 13,2013, Staff Presentation ("August 13, 2013, Staff Presentation), p. 20.

[46] It should be noted that WSPA's written comments submitted on October 16, 2013 (WSPA 1) were incorporated by reference as part of Valero's comments submitted on October 17, 2013 (VALERO 1). As these written comments are duplicative, the responses to WSPA 1 serve to address both simultaneously.

Comment: We support ARB's use of the CWB, and we support the changes to the MRR that would support the change to the CWB. (WSPA 3)

> **Response:** Thank you for the support.

Complexity Weighted Barrels vs. Simple Barrels

B-8.4. Comment: One product that distinguishes [our smaller] refineries [from large refineries] is that many of them produce asphalt. Asphalt is made from the heaviest bitumen part of a barrel of oil. Asphalt refineries don't have expensive and very energy intensive processes the big bubble refineries use to crack these launching molecules of gasoline and diesel fuel. Although the CWB methodology addresses the thermal efficiency of refinery processing, it does not address the processing efficiency of the simple barrel approach used partly in the first compliance period. (PARAMOUNT 2)

> **Response:** The CWB methodology addresses the efficiency of refinery processes, including both ways that GHG emissions can be produced: from fuel consumption and as process emissions. ARB staff has no reason to believe that the CWB factor for asphalt production is inappropriate and has received no input or data specifically asserting that this is the case. Asphalt production is included as a process unit under CWB. It is not clear what the commenter means by "processing efficiency" and in what way it believes that CWB is incomplete.

Regulatory Process

B-8.5. Multiple Comments: The Coalition appreciated the October 7, 2013, presentation and discussion opportunity provided by the California Air Resources Board (CARB or Board) to walk through the staff proposal related to refinery benchmarking, including the proposal to adopt the Complexity Weighted Barrel (CWB) methodology inclusive of "off-site" factors and to separately benchmark atypical refineries.. The ability to fully comment on the above is an important step in the regulatory process. These amendments have very significant business ramifications and having only one week to prepare comments has limited the Coalition's ability to conduct in-depth analysis on the proposals…

Lastly, it is noted that this is the second time the administrative process associated with refinery benchmarking has been truncated at the end of a rulemaking. In both the 2010 rulemaking and in these 2013 amendments, significant decisions that affect the viability of entire facilities have had to be made in a rushed manner and without the benefit of a fully transparent set of data or robust public process. Because the actual language of the proposals has yet to been provided to stakeholders, we request that the process leading up to a required 15-day regulatory amendment package be given the utmost of deference to the need of stakeholders to understand and analyze staff's proposal and its underlying support data. (CFEA 1)

Comment: Lastly, we note that the administrative process associated with refinery benchmarking has been truncated at the end of this rulemaking. These amendments require in-depth analysis and subsequent significant decisions which affect the viability of entire facilities. The idea of a robust public process is defeated by having to make such critical business decisions in a relatively rushed manner. Because some important portions of the actual language of the proposals have yet to be provided to stakeholders, we request that the process leading up to a required 15-day regulatory amendment package be given the utmost of deference to the need of stakeholders to understand and analyze Staff's proposal and its underlying support data. (CFEA 3)

Comment: Without a clear and timely proposal, the refining industry can not accurately review and evaluate the proposal(s) in front of us. (CFEA 2)

Comment: While we support a large portion of the publicly noticed portions of this rulemaking that indeed significantly improve the existing Program, there are a variety of new, substantive issues that as of the Board hearing date were not in writing. In fact, "staff thinking" was only recently shared at the recent October 7, 2013 workshop over 30 days into the 45-day public comment period. These eleventh and a half-hour proposals have not been a meaningful part of the regulatory process leading up to, or including, the 45-day comment period. It is unfortunate that we have not been able to fully analyze the operational and economic impacts of these proposals.
P66 has concern over the following issues and formally requests more time to consider their impact on our business:

1. The non-Atypical Refinery benchmark proposal
2. Staff proposal over "jointly-operated" facilities (Definition of refinery)
3. Hydrogen production benchmark
4. Calciner benchmark
5. Calciner Cap Adjustment Factor

These benchmarking and allocation issues need to be thoroughly discussed, and will require adequate time for evaluation and comment. We are asking that the Board bring back these substantive issues to a future CARB hearing….

These issues have significant costs associated with them and are items that deserve full stakeholder vetting before they are adopted in the required 15-day amendment package. As of right now you only have concepts before you but they are yet-to-be drafted, or seen by stakeholders.

… We believe there is sufficient time for careful analysis of the newly issued written proposal and subsequent dedicated Board hearing since refinery benchmarking for the Second Compliance Period are note needed before October 2014. A similar scenario of "deadline rulemaking" transpired on October 20, 2011, during the initial adoption of the Cap and Trade Regulations. However, in contrast to 2011, when the program faced possible expiration and the potential for re-review of the entire program in another regulatory process, there is no such constraint this time.

Providing a transparent and data driven process so that stakeholders can fully analyze the "new concepts" and more intricate parts of new proposals placed before you and respond will achieve a more solid program with fewer unintended consequences. New concepts introduced more than one month into a 45 day comment period is a recipe for unintended consequences. Because a 15-day amendment package will be needed, the regulatory mechanisms are already in place to direct staff to take the time needed, and P66 respectfully requests that the items of Opposition listed below are allowed to be fully vetted after being put in writing, and properly noticed prior to a final vote by the Board….

P66 is in the awkward position of commenting on oral presentation held at the October 7, 2013 workshop announcing significant benchmarking policy more than a month into the already limited 45-day review period. In 2011, we faced a similar truncated timing scenario on the initial Cap and Trade proceeding. The previous administrative process was truncated due to the clock running out on the original Cap and Trade rulemaking resulting in the Board directing staff on October 20, 2011 to re-evaluate the refining sector in-state competitiveness. The in state competitiveness was not evaluated, the resolution ignored and here we are today, with an even more truncated process, literally 30 plus days into a 45-day package with only a October 7, 2013 PowerPoint to make assumptions from. Understanding what CARB staff might or might not think on decisions that will cost P66 tens of millions of dollars is not an acceptable process. Significant decisions that impact the viability of our operations have been twice-truncated and rushed to the end of a 45 day comment period. Multi-million dollar decisions are being made without the needed data analysis and, as a result, the policy justifications are unclear. These decisions impact how many allowances a facility will be provided and directly affect the California refining sector. Our testimony and position must be extracted from presentations and staff discussions on a very short time line with only the promise of detailed language to come to the Board. By taking a rushed approach to this rulemaking, the state risks placing negative unintended consequences on the refining sector, which could result in unnecessary job loss,, increased importation of intermediate and finished product from outside California, and increased overall carbon emissions. Benchmarking is too important to get it wrong.

Because the actual language of the proposal has yet to be provided to stakeholders the evening before the hearing, we request that the process leading up to the required 15-day regulatory amendment package be brought back to the board for review and additional justification. (PHILLIPS 1)

Comment: If CARB doesn't do this the right publicly and include our input, it will give an unfair competitive advantage to some in-state and all out-of-state importers of intermediates and finished products. Any small refinery should be looked at on its face. Don't look at it as a refiner. Look at the size and configuration of the existing site. Sufficient time for careful review and analysis of this morning's new proposal and a subsequent dedicated Board hearing since refinery benchmarking methodology does not take place under a new methodology until 2014 is needed. USW wants to hear this, and we are being denied active participation in this process. We feel that this is very important to ensure our good union jobs that we have today and into the future. (USW 2)

Comment: Back in 2011, I actually addressed you guys on this issue. And I recall coming up -- you guys came up with a resolution at the time. Well, I'm here again, and we're once again up against a deadline. And that's when you guys actually came up with that resolution. Now we have one hour to seek changes. New concepts that further disadvantage smaller refineries have been introduced and you are considering voting on this. We didn't find this out until we were actually on the plane. We almost missed this hearing. So from a personal perspective, from a union perspective, from a union steward's perspective to represent several hundred workers within my facility, I would ask that you guys take a step back and allow us the opportunity to be able to address the changes that you proposed that we found out about this morning. We think some other things should be done. We think some Q and A should be done. We have some questions. And I'm sure my group has more questions than I can even think of. So that's basically what we are asking. This is a disadvantage from the perspective in which we see it. (USW 3)

Comment: These changes under atypical and typical benchmarks we were not aware of until this morning after we get off the plane. And the schedule was such that we almost missed this hearing… So we would request, as Lisa said, that that part of this proposal be subject to a longer hearing process of 40 -- I thought I heard somebody say it was a 45-day process, but we would request that you consider separating out that part and giving all the parties a little longer time to consider all that. (USW 4)

> **Response:** The central proposed change to refinery allowance allocation was to change from the use of complexity-weighted tonnes (CWT) to CWB as the basis for allocation. CWB is a complex GHG efficiency metric based on extensive refinery data. Therefore, ARB staff could only consider using it after receiving a sufficiently detailed definition of CWB and comparing it to California data. ARB staff received the necessary CWB definition proposal on May 17, 2013. Only after receiving this information could staff begin to assess how to incorporate the metric into the Regulation, which staff did in the five months between May and the October 2013 Board hearing. Staff continued to analyze CWB and all other pertinent information related to this change from October 2013 through April 2014.
>
> As part of its analysis of the CWB proposal, ARB staff conducted a survey of California refineries to collect and understand the refinery-specific data which would be used to calculate CWT or CWB, as well as CWB-related emissions data. This survey began in June 2013. ARB continued to receive survey data corrections from refineries through late 2013. As of the October Board hearing, staff were still receiving survey data from refineries.

ARB staff disagrees that the regulatory process has provided insufficient time and opportunity for stakeholder analysis and input. ARB staff interacted with all petroleum refineries throughout this process, and shared all data and information surrounding benchmark proposals with the refineries to the extent that staff would not be revealing confidential business information about another entity. This process included ARB workshops dedicated to refinery, hydrogen, and calcining allowance allocation on August 13 and October 7, 2013, informal meetings with the refining sector, and numerous meetings with individual petroleum refineries.

Workshops were announced on ARB's website and via e-mail announcement lists which include all parties who have requested to be on these lists. Documents from these workshops are available at http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm.

ARB has released written proposals addressing those refinery allowance allocation issues which affect the most stakeholders and the most GHG emissions. Preliminary staff thinking was presented at the August 13 workshop. As other commenters noted, policy proposals have been described in the October 7, 2013 workshop documents. More recently, the preliminary proposals were described in Attachment A to Resolution 13-44. The Board approved the resolution and directed the Executive Officer to "consider the topics set forth in Attachment A, and make such additional conforming modifications as may be appropriate and any additional supporting documents and information available to the public for a period of 15 days, provided that the Executive Officer shall consider such written comments as may be submitted during this period, shall make such further modifications as may be appropriate in light of the comments received…." Informal 15-day language was provided on January 31 in order to allow stakeholders time to respond before the final formal 15-Day Modifications were released. Substantive refinery-related changes made after the informal draft were communicated verbally to affected stakeholders prior to the formal 15-Day Modifications release. Formal 15-day language was released on March 21.

Regarding evaluation of in-State competition, on October 20, 2011, the Board directed ARB staff to "continue to review information concerning the emissions intensity, trade exposure, and in-State competition of industries in California, and to recommend to the Board changes to the leakage risk determinations and allowance allocation approach, if needed, prior to the initial allocation of allowances for the first or second compliance period, as appropriate, for industries identified in Table 8-1 of the Cap-and-Trade Regulation, including refineries and glass manufacturers." ARB staff continues to review these areas, including using multiple data sources to examine business movement within the State. ARB staff has also made policy changes related to this Board direction. For example, the current regulatory amendments have increased the Assistance Factor to 100% for the second compliance period while ARB staff and its contractors continue to analyze potential leakage of industrial activity to outside

California. This is the maximum value for the Assistance Factor, which is the factor which incorporates leakage risk into allowance allocation.

Support for Separate Benchmarking of Atypical Refineries

B-8.6. Multiple Comments: Formal recognition and separate benchmarking of "atypical" refineries in the Program is a key policy recommendation that the Coalition is very supportive of implementing. Not all refineries in California are large and complex, the atypical category appropriately recognizes this reality. The concept of "atypical" is regional in nature, therefore it is entirely appropriate to establish criteria for an atypical California refinery based on the state's existing inventory of refineries. Each region of the world has a different distribution of refinery size, complexity, configuration and age, therefore a typical (or atypical) refinery is region-specific. The Coalition supports the chosen metrics of combined size and complexity. In addition, the Coalition generally supports the proposed California-specific atypical criteria metrics of less than 12 process units and 20 million barrels of crude throughput per year, but understands that the actual regulatory language still needs to be written and analyzed. (CFEA 1, CFEA 3)

Comment: LTR fully supports staff's proposed decisions to recognize "atypical refineries," as well as the inclusion of "off-site" and "non-crude sensible heat" factors within the Complexity Weighted Barrel (CWB) methodology.

With these key concepts included in the 2013 cap-and-trade amendments, LTR believes that the CARB is on the right path to ensure equitable treatment of all regulated entities, especially the atypical refineries. (LTC 1)

Comment: Staff is proposing to benchmark "atypical" refineries separately under CWB. Kern strongly supports Staff's proposal and the acknowledgement that the efficiency limitations imposed by refinery size and complexity are critical for benchmarking purposes. At the August 2013 workshop, Solomon expressly stated that small refineries lack opportunities for heat integration and to advantage themselves of the economies of scale, which benefit large, complex refineries. Solomon further stated that a smaller refinery cannot fairly be compared to the efficiency of a super refinery. Kern appreciates Staff's analysis of California refineries to determine those "atypical" refineries whose structural constraints justify the proposed separate benchmark. Staff proposes to define "atypical" facilities as those having less than 12 process units and less than 20 million barrels crude through the atmospheric distiller per allocation year. Although without the benefit of the actual regulatory language, Kern is supportive of the atypical definition proposed by staff. Truly, one size does not fit all and Kern applauds Staff's proposal. (KERN 1)

Comment: Underlying ARB's atypical benchmarking proposal is testimony provided by worldwide acknowledged refining expert Solomon Associates (Solomon) at an ARB workshop held August 13, 2013. Solomon pointed out that because of the efficiency limitations associated with a lack of heat integration opportunities and the inability to advantage themselves of economies of scale, smaller, less-complex refineries cannot be fairly compared to the major large complex refiners in California. ARB also has precedent in acknowledging the uneven playing field of the California refinery sector, for example: (1) in setting separate compliance targets for Non-EII versus EII refineries in the first compliance period for Cap and Trade; and (2) in Low Carbon Fuel Standard, the proposed low-energy-use low-complexity refinery provision, which will acknowledge the lower carbon intensity inherent to fuels produced by low-energy use refineries. The United States EPA Energy Star Program also groups refineries into size based peer groups for determining energy efficiency. The Energy Star Program acknowledges that it is inappropriate to judge smaller refineries by larger refineries' efficiency standards, which is being similarly acknowledged by ARB in this most recent proposal to discern atypical refineries from typical refineries for the purpose of benchmarking and allocation of allowances.

Solomon representatives stated that in every benchmarking they have conducted and/or studied worldwide, each region has had its own particular "atypical" refineries. Ecofys, ARB's expert, when advising ARB to consider and address the issue of atypical California refineries in an August 2012 report, cited to the European Union as an example of a region that dealt separately with atypical refineries. However, obviously, what may have represented an atypical refinery in Europe does not determine what may be an atypical refinery in California.

Kern appreciates Staff's analysis of California refineries to determine those "atypical" refineries whose structural constraints justify the proposed separate benchmark, which takes into consideration Solomon's testimony regarding the pertinent size and complexity limitations that are indicative of atypical refineries. Staff proposes to define "atypical" facilities as those having less than 12 process units and less than 20 million barrels crude through the atmospheric distiller per allocation year, which Staff stated was a natural size and complexity break for the refining sector. Although without the benefit of the actual regulatory language, Kern is supportive of the atypical definition proposed by Staff. Truly, one size does not fit all. Kern applauds Staff's proposal and eagerly awaits release of proposed regulatory language for further review and solidification of the proposal. (KERN 2)

Comment: Alon supports the establishment of the "atypical" refinery category, the proposed benchmark and the category criteria. This is a key recommendation because not all refineries were built the same, nor do they operate the same…

The current Cap-and-Trade Regulation contains a bifurcated methodology for the free allocation of allowances to the refining sector. This is a recognition that not all refineries can be compared against each other. Alon supports the current staff proposal to continue this split using an "atypical" refinery concept. Additionally, Alon supports the proposed benchmark level. The numeric criteria for atypical eligibility is reasonable... (PARAMOUNT 1)

Comment: And the reason we formed the coalition was to address the issue of benchmarking and how one product, one benchmark could possibly negatively impact the smaller refineries. So I'm here today to support the fact that we were able to reach resolution on a number of issues, assistance factor, the establishment of an atypical benchmark, and actually the metrics for that atypical we certainly think satisfy what a small refinery is. (CFEA 4)

Comment: The diversity of the California refinery sector makes applying a single benchmark problematic. And staff's proposal most recently largely addresses concerns that we previously have regarding these competitive disadvantages and inequalities of refinery allocations. Kern appreciates staff's in-depth analysis of California refineries that identify the typical refineries whose structural constraints, lack of economies of scale, and lack of opportunities for heat integration justified this separate benchmark. (KERN 3)

Comment: Secondly, we support the staff's proposal to benchmark atypical refineries such as us separate from our more typical counterparts.

And third, we support staff's proposal to define a California atypical refinery as one of those having less than twelve process units and processing less than 20 million barrels of crude per year. (LTC 2)

> **Response:** ARB staff appreciates the support for its earlier proposal, but ultimately proposed only one CWB benchmark for all refineries in the 15-Day Modifications to the Regulation.

Clarification of Atypical Definition

B-8.7. Comment: We have some questions about the definition of atypical and the 12 process units. Is that 12 process units as defined in CWB? If you have 2 crude units, would that be one process? Or would that be individual? (PARAMOUNT 3)

> **Response:** ARB revised its proposal in the 15-Day Modifications to remove the "atypical" refinery distinction, so this comment is now not applicable to the final proposed regulatory changes proposed in the 15-Day Modifications. Units that would be reported under one row in Table 1 "CWB Functions and Factors" of the MRR will be considered as one process unit.

Data Used for Previously Proposed Atypical Definition and Benchmarks

B-8.8. Comment: Are we going to see any more data? You set atypical at a certain size. Without any further data from ARB it is hard to determine your methodology and the rationale behind the proposal. Is there going to be a data release? All we are responding to is what you proposed, not how or why you proposed it. (CFEA 5)

Comment: What other data releases will CARB provide to the stakeholders to either review or evaluate in term of establishing the benchmarks? (RCFEA 1)

> **Response:** ARB staff is not planning to release data on the number of process units and amount of atmospheric distiller throughput at each refinery because they are confidential business information. However, related data on refinery process unit capacities are available from the Energy Information Administration, and summary analyses of various ARB data have been included in the documents for the October 7, 2013 workshop and in other ARB public documents.
>
> ARB staff has no specific plans to release further data related to defining refinery-related benchmarks beyond what has already been released publically.

Request for Different or More than Two Atypical Refinery Categories

B-8.9. Multiple Comments: We support ARB's recognition of the diversity within the refinery sector by proposing to establish a separate benchmark for "atypical" refineries.[47] Rather than attempting to draw a line between "typical" and "atypical" refineries, however, we recommend ARB establish additional benchmarks that reflect the varying size, complexity, and corresponding emission reduction opportunities at California refineries.[48] By grouping comparable facilities, this approach would adhere to the fundamental principle of benchmarking to compare 'like against like,' and encourage all facilities to be the best they can be within their respective class.

While staff's latest proposal is a step in the right direction, we remain concerned about the ability of smaller, less complex, and otherwise atypical facilities to have fair opportunities to compete. We ask that staff evaluate establishing additional benchmark categories to ensure incentives are properly aligned to drive additional investment in emission reduction projects throughout California's refinery sector. (NRDC 1)

Comment: With this in mind, P66 has concerns that certain benchmarking proposals will have the unintended consequences of tilting the in-state competitive balance. If CARB proceeds with their current single "typical" benchmarking proposal, some in-state refiners will be required to purchase 25% of their allowances while other refiners will have virtually no obligation to purchase in the Program because most of their allowances are given to them for free….

We are particularly concerned that the Board give critical oversight to the last minute competitive typical refinery benchmark. Unlike the Atypical benchmark which has been seriously considered by staff and Ecofyrs and Solomon in workshops and studies, the non-Atypical category (larger refineries) has not had this type of data analysis by staff or stakeholders. The "typical" benchmark conflicts with both Solomon's six EDC

[47] ARB Staff Presentation, "Refinery Allocation Under Cap-and-Trade Proposed 2013 Amendments," October 7, 2013, available at: http://www.arb.ca.gov/cc/capandtrade/meetings/100713/refinery_workshop_presentation_10_7_13.pdf.
[48] As data on refinery throughput and other market sensitive information is not publically available, we defer to ARB on how many benchmarks to establish based on efficiency breakpoints in the data.

categories as well as EPA's six categories for refinery energy efficiency under the Energy Star Program. Moving ahead with adoption of this benchmark would be premature and eliminates any Board review or stakeholder participation. We struggle to carry out a thorough analysis and develop conclusions on principles that are not in writing. We believe CARB would benefit from careful stakeholder analysis of new last minute additions to the typical refinery benchmarking proposal.

We are concerned that the current "staff thinking" will create immediate competitive issues within the refining industry in California. We have asked the board previously and ask the board again to benchmark refineries against refineries of similar size and complexity. It is clear that larger industrial facilities are, and can be, more efficient through economies of scale.

The board needs to determine its goal is for refinery benchmarking. If the goal is to set the benchmark based on the most efficient refineries in California, regardless of size, the result is an immediate competitive disadvantage for the relatively smaller refineries. This competitive disadvantage comes from raising their cost of business by requiring them to purchase additional allowances. We cannot rebuild our refineries to be double their size to achieve the same efficiency as the largest refineries in the state. We cannot combine our two Southern California refineries that are five miles apart or our two other refineries in central and northern California that are 200 miles apart. We can maintain or improve efficiency to benchmark well against similar size and complexity refineries.

We have consistently recommended a benchmark that incorporates size and complexity. This can be an equation or a set of groups. The federal EPA took this very approach when it developed its Energy Star Program. It benchmarked refineries against similar size and complexity refineries to determine Energy Star Eligibility. Otherwise there would have been very few small Energy Star Refineries.

Solomon Associates, who staff selected to calculate refinery carbon efficiency, also benchmarks by refinery size and complexity. Our industry benchmarks our refineries using the Solomon methodology of six distinct "EDC" groups…

The October 7, 2013 oral presentation and corresponding PowerPoint recognize two benchmarks, one for atypical and typical refineries. The distinction is based on having less than 12 process units and less than 20 million barrels crude through the atmospheric distiller during an allocation year. [This] is a step in the right direction in setting a benchmark that recognizes less complex or atypical refineries. (PHILLIPS 1)

Comment: Specifically related to the atypical proposal, could you elaborate on how you got to the 12 process units, and how you got to the 20 million barrels crude per year criteria as a defining line for complexity?...

Did ARB consider any other cut-points? Additional cut points? (KERN 4)

Comment: However, in the Solomon presentation to ARB (August 13, 2013), Solomon acknowledged that there are limitations to the application of CWB and that "atypical" refineries would likely require a different benchmarking approach. While ARB staff has acknowledged this qualification in the October 7 presentation, the criteria ARB set forth to define "atypical" refineries are inappropriate and stray from the accepted understanding and criteria for identifying these facilities. Given the limited population of refineries in California, the proposed ARB approach can potentially skew the allocations provided to industry and create competitive disadvantages.

Both Solomon Associates (CWB presentation to ARB, August 13, 2013) and Ecofys (presentation to ARB discussing refinery benchmarking in the second compliance period, August 28, 2012) specifically discuss the term "atypical" as that term may describe a refinery whose emissions cannot be accurately estimated using the CWB or CWT methodology.

The Ecofys presentation states, "The CWT approach is not suitable for atypical smaller refineries," and cites the definition applied in the EU as follows:
"EU definition: atypical refineries do not produce a...'Mix of refinery products with more than 40% light products (motor spirit (gasoline) including aviation spirit, spirit type (gasoline type) jet fuel, other light petroleum oils/ light preparations, kerosene including kerosene type jet fuel, gas oils).'"

The combination of these statements on the same slide (#27) imply that being a smaller refiner does not preclude the application of the CWT factor but that a smaller refiner may meet the definition of "atypical" by nature of its product slate.

The Solomon presentation states the following: "Atypical" refineries may be handled separately
o Extremely small sizes
o Performing predominantly specialized functions (such as bitumen production or lube oil manufacture)
o Atypical product slate (such as <40% light products including motor gasoline, aviation gasoline, kerosene, and diesel/heating oil).

Solomon further clarified that "small size" is not the defining characteristic of "atypical." While there was some acknowledgement that the CWB/CWT correlation begins to lose its high level of accuracy for facilities below 40,000 BPD crude charge, there was no mention or discussion of equating "small" in the context of crude charge capacity to the number of process units. Both Ecofys and Solomon are largely in agreement as to the general criteria that should be applied when determining if a refinery is "atypical" and in their support for the definition used in the EU.

In the October 7th presentation, ARB proposed very different criteria for determining "atypical" than those listed above:
• Defined as having < 12 process units and < 20 million barrels crude (55,000 BPD) through the atmospheric distiller / year (during allocation year)

• If jointly operated with another refinery, must meet those criteria for the combined facilities.

ARB has not provided a substantive basis for these criteria, nor has it provided any basis for concluding that the CWB methodology is not appropriate for refineries that meet this description. Both of the proposed criteria focus on the size of the facility (rather than on the nature of the product slate)-criteria which deviate significantly from the common understanding of "atypical." Further, the size cut-off employed by ARB is much larger than that used by the EU. This approach inappropriately broadens the definition of "atypical" such that otherwise typical refineries may receive the benefit of a larger benchmark value, which equates to disproportionately greater free allowances. When comparing the CWB charts on pages 17 and 27 of the October 7th presentation, it is clear that the proposed criteria have broadened the number of atypical facilities such that sources clearly falling on the CWB curve will be treated differently. This creates competitive issues within the sector that could be avoided if the accepted definition of "atypical" were used.

ARB criteria for determining "atypical" also lack consideration of the magnitude of GHG emissions. The Ecofys report, "Development of GHG efficiency benchmarks for the distribution of free emissions allowances in the California Cap-and-Trade Program" (August 20, 2012), states that "in Europe, emissions from atypical refineries represent a very small share of the total emissions of the refinery sector." Table 11 of the Ecofys report lists five refineries that emit less than 35,000 MT CO2, with the qualification that these five refiners are "Potentially atypical refineries together with indication for not being a 'mainstream' refinery." ARB does not appear to have addressed emissions in their "atypical" criteria nor provided a comparison of GHG emissions of the "atypical" refiners (per ARB's criteria) in the context of the Ecofys analysis or relative to non-atypical refineries. Given this recognition by the EU and Ecofys that emissions are relevant to the "atypical" analysis, we request that ARB modify their criteria accordingly…

In sum, "small" does not necessarily equate to "atypical." A deeper analysis of the refinery product slate and the magnitude of associated emissions is required in making any designation of "atypical" to a refinery. Valero recommends that ARB employ the accepted and recommended definition of "atypical," focusing on product slate, in determining which facilities should be treated outside of the Solomon CWB benchmark process. Doing so will eliminate the potential competitive concerns created by the current proposal while providing a defensible basis for refinery allocations in the second and third compliance periods. (VALERO 2)

Comment: On top of creating in-state competitive issues, any cost burden added to a California refinery makes it less competitive versus refineries outside of California who can import into California without Cap and trade compliance cost. Without any protection from imports or finished and intermediate products, the real world barge shipping costs to import fuel in California are only about three to six cents. You could see how that could be a problem. You can barge from Washington state. We have a refinery into Washington state. You can barge from Canada right into Los Angeles. You can barge from Asia right into Los Angeles.

So this is very critical on -- the marine terminals are privately owned. You don't know what's coming in and what's going out. We have our own marine terminals. So do our competitors. So we have concerns that certain benchmarking proposals will have unintended consequence and tilting the in-state competitive balance.

If CARB proceeds with the current single typical benchmarking proposal, some in-state refiners will be required to purchase 25 percent of their allowances, while other refiners will have virtually no obligation to purchase in the program, because most of their allowances will be given to them for free. (PHILLIPS 2)

Response: ARB staff agrees that the definitions for “atypical” and “typical” refineries are problematic, and revised its proposal in the 15-Day Modification to remove these distinctions.

Several commenters expressed concerns about equity and competition. The question of competition with out-of-State refineries is separate from the question of atypical benchmarking. Within the State, any definition of “atypical” could affect the competitive balance among refineries. Having a single benchmark for all refineries avoids this problem. A single benchmark affects in-State competition only insofar as some refineries have higher emissions per CWB than others, thereby creating appropriate incentives for lower emissions per CWB.

In ARB staff’s analysis of whether CWB is fair to atypical refineries, typical and atypical refineries were subjected to similar amounts of analysis. Neither Ecofys nor Solomon Associates endorsed any one definition of atypical, although both suggested that it has something to do with size, product mix, and refinery configuration, all of which are related. Neither Ecofys nor Solomon Associates made a specific recommendation regarding whether ARB staff should use a separate benchmark for atypical refineries or a single benchmark for all refineries, although both made comments related to the issue, in response to ARB staff and/or stakeholder requests.

During ARB staff’s main analysis of atypical vs. typical refineries, ARB staff divided refineries into “typical” and “atypical” following natural breaks in California refinery data on size and number of process units. Since process units are used to calculate CWB, they appeared to be the most appropriate basis to identify which refineries are least likely to be well represented by CWB. ARB staff also checked that these definitions align somewhat with patterns of what kinds of process units are present at refineries and with product mix. This is how ARB staff selected the initial “atypical” definition criteria of less than twelve process units and less than twenty million barrels of input to the atmospheric distillation unit. Unfortunately, ARB staff cannot provide more detail about how the definitions were generated without releasing confidential data.

ARB staff also considered other definitions of “atypical,” including the EU definition of producing less than 40% light products. This definition would have resulted in a smaller number of “atypical” refineries, making the atypical benchmark value less likely to be appropriate.

A separate benchmark for atypical refineries was considered because of the nature of CWB, as described in response to comments on the 15-Day Modifications. This reasoning does not extend to considering more than two benchmarks, or the type of equation-based benchmark suggested by one commenter. Other programs or analyses may use refinery groupings, but those programs have different designs and/or goals than California’s Cap-and-Trade Program. Size-based benchmarks are not consistent with the design of the Cap-and-Trade Program.

Support for Jointly Operated Refineries Definition

B-8.10. Comment: Ecofys also states in its presentation and report that “in case a smaller refinery is connected with a nearby larger refinery, these refineries could be grouped together to form one mainstream facility for the purpose of applying the CWT methodology.” CARB should ensure that the same is done in the Solomon CWB benchmark process; that is, if two refineries owned by the same company are grouped together as one refinery for general industry reporting, those refineries should also be combined for the sake of the CWB benchmark process. (VALERO 2)

Response: ARB revised its proposal in the 15-Day Modifications to remove the atypical refinery distinction. Under the 15-Day Modifications, the typical and atypical benchmarks were merged into a single benchmark, and a jointly operating definition is no longer necessary.

Opposition to Jointly Operated Refineries Definition

B-8.11. Multiple Comments: But one aspect of the staff proposal is problematic – requiring “jointly operated facilities” to be considered as a single facility for purposes of an atypical determination. (CFEA 1)

Comment: But one aspect of the staff proposal is still problematic–the potential language surrounding “jointly operated facilities” and the inappropriate attempt to combine an otherwise small refinery with another facility for purposes of allowance allocation. The definition of a stationary source has been established over the many decades of air pollution control, and is defined in both the Mandatory Reporting and Cap-and-Trade Regulations, as is the definition of a “Petroleum Refinery” or “Refinery.” These two distinct definitions are complementary and consistent in that each location/operation is a separate and distinct compliance entity. Excluding a smaller less-complex refinery, that would otherwise meet the definition of “atypical”, solely because it is associated with a separate (and equally specialized) facility is an application of inconsistent policy. This “carve out” is especially troublesome as it targets and may only impact a single facility in California. “Jointly-operated” is an undefined term that is unnecessary and inconsistent with existing regulatory treatment of facilities. The operations of this type of smaller, less-complex refinery that performs specific functions are equal in their susceptibility to emissions leakage as the other atypical refineries. The Coalition recommends that the Board remove the suggested requirement that an otherwise qualifying atypical refinery not be considered as such based on the concept of joint operations. (CFEA 1, CFEA 3)

Comment: The numeric criteria for atypical eligibility is reasonable, but Alon does not support the concept of "jointly operated" facilities. Especially as this yet-to-be-defined concept could have negative implications to an otherwise "atypical" refinery, potentially including Paramount. (PARAMOUNT 1)

Comment: PHILLIPS 86 operates five distinct facilities in four different cities in the state of California (four refineries and a Calciner) subject to Cap and Trade. While not in writing to evaluate prior to the CARB hearing on October 25, 2013, CARB staff floated a new definition of facility. The long standing definition of "facility" is well known in stationary source permitting and federal GHG reporting. However, staff's newly proposed definition for "jointly operated" to be included in the "atypical" refinery category is a new concept. Trying to link facilities above and beyond the current definitions in Cap and Trade and MRR is inconsistent and has no policy justification. Since the term 'jointly-operated" has not yet been defined, it is nearly impossible to draft intelligible comments for the Board while in concept with no written language. CARB staff made it very clear at the October 7 workshop that staff our Santa Maria facility was targeted for exclusion when creating the definition. The PHILLIPS 86 Santa Maria and Rodeo refineries are separated by xx [sic] miles within the state. Santa Maria's intermediate product is shipped by common carrier pipeline to the San Joaquin Valley where it is transferred for further processing. Because it only produces intermediate products, much of its production can be replaced by international-sourced waterborne shipments to the Rodeo facility. As a result, the current staff "staff thinking" regarding "jointly operated" facilities will favor importation over in state manufacturing of intermediates. A key objective behind the free allowance mechanism is to prevent leakage but staff's current path seems counter to that objective. As such, we are struggling to understand the policy argument for staff's proposal.

CARB' s contractor Ecofys reported this information to CARB in the August 2012 Ecofys report on benchmarking. CARB's utilized Ecofys as its expert on benchmarking. On several occasions they list Santa Maria as a separate facility from Rodeo. See footnote "c" on page 7 (pdf pg 12) and then in Appendix C on page 72 (pdf pg 77).

The footnote cites P66 corporate documents and says: "Became PHILLIPS 86 in May 2012. The San Francisco Refinery comprises two facilities linked by a 200-mile pipeline: the Santa Maria facility located in Arroyo Grande and the Rodeo facility in the San Francisco Bay Area. The Santa Maria facility upgrades heavy crude oil for final processing in the San Francisco Bay facility. The Los Angeles Refinery Complex is composed of two facilities linked by a five-mile pipeline. The Carson facility serves as the front end of the refinery by processing crude oil, and Wilmington serves as the back end by upgrading the products (source: 10-K forms)"…

The October 7, 2013 oral presentation and corresponding PowerPoint recognize two benchmarks, one for atypical and typical refineries. The distinction is based on having less than 12 process units and less than 20 million barrels crude through the atmospheric distiller during an allocation year. While this is a step in the right direction in setting a benchmark that recognizes less complex or atypical refineries, the arbitrary policy decision to "require jointly operated facilities" to be considered as a single facility is not. This policy specifically excludes our smallest refinery, located in San Luis Obispo County, from the designation of atypical. CARB justification was vague with oral explanation alluding that facilities linked by pipelines mean that one refinery cannot operate without the other. The San Francisco refinery located in Contra Costa County, is 250 miles in distance from the Santa Maria Refinery.

CARB must not arbitrarily discriminate against certain refineries. While the Santa Maria Refinery refines intermediate products that are utilized by Rodeo to make finished product, Rodeo could operate without the intermediate made by Santa Maria and shipped by pipeline. Intermediate products are commodities that could be brought to Rodeo by ship, barge, rail or other pipeline purchased from another source: Penalizing both facilities by entertaining the concept that a single refinery can consist of pieces within a 250 mile radius undermines the future viability of the facility and improperly treats the combined facility as a single typical refinery which it clearly is not. If the goal of the cap-and-trade program is to attract investment at the least cost, comparable facilities would benchmark with ‘like against like’ based on their refined products, size and configuration. Incentives should instead be to encourage a facility to be the best that it can be.

CARB’s oral proposal and corresponding PowerPoint suggests fundamental changes to the longstanding definition of a stationary source facility. By requiring jointly operated facilities to be considered as single facility for purposes of an atypical determination, CARB is modifying the overarching policy definition of federal and state stationary source permitting. Many refineries are accessible by underground pipeline to receive or deliver a multitude of refining feed stocks. Facilities can be jointly operated by company ownership, long-term contract, or commodity streams. The definition of facility embedded in the CARB MRR regulation definition is why we report our 5 operating sites separately to CARB.

"Facility," unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas ....".

The key words here are "continuous or adjacent". Modifying the regulation to capture refiners instead of refineries will create competitive disadvantages for only PHILLIPS 66. The policy justification and objective is punitive and will not result in improved energy efficiency on-site. (PHILLIPS 1)

Comment: And there is a difference between a small refiner and small refinery. We think atypical focuses on small refinery. One last concern is the issue of a jointly operated concept of a small refinery is somehow attached to a larger refinery that you have to allocate the allowances as one big group. We think that's counter to the definition of atypical. And the reason something is atypical with integration and other issues.

We will certainly be working with staff to figure out what that definition actually means, because we haven't seen it yet. But that's our one remaining issue as a coalition. (CFEA 4)

Comment: We had a question about atypical and connected refineries. Most refineries are connected via pipeline to another refinery. Broader questions is: when are we going to see language, relating to defining terms, etc. And a specific question: what are you thinking about in terms of combining refineries for atypical…

Can one operate without the other? We have refineries that cannot process a whole barrel and cannot operate without someone taking the products, and vice versa. It gets complicated quickly. Is there an ownership aspect to it, proximity aspect? This is important to at least one if not two facilities, so the ability to respond to the question depends on the scope of the answer. (CFEA 5)

Comment: Wouldn't defining joint operation based on not producing primary product bring a lot of other people into the mix? People that make naptha, long-term contracts… that could be a really slippery slope…

What if the companies are different. For example you have a company that has an intermediate refinery and a primary product refinery? If they're different companies it's ok but if they're combined it's not? Is it a property issue? An ownership issue? A usage issue? What is the definition?

Just thinking about how your goal is to export this to other places. How does that provision help in exporting [Cap-and-Trade] to other states and nations? (PHILLIPS 5)

Comment: Back to the linking issue. What is the purpose of excluding those facilities [jointly operating facilities from the atypical category]?...

It's a slippery slope. When you consider linkage in that way, you can make a case that a lot of facilities in the state are linked. Perhaps ARB should consider or look at how facilities are treated under LCFS or MRR, so they are treated consistently across regulations. (KERN 4)

Comment: There is a definition of a facility in the regulation, which defines it as an independent site, not contiguous or adjacent I would encourage you to look at how that is defined. EII is the last methodology. If there is an EII for linked facilities, and that is the methodology for benchmarking, then it makes a little more sense to group. But if CWB can be done on an individual facility basis, why then propose linkage? (CFEA 5)

Comment: Let's take for example my Rodeo in Contra Costa and Santa Maria, which is San Luis Obispo near Avila Beach. They're jointly connected by pipeline, but the pipelines aren't direct. The pipeline from Rodeo, which is very small, smaller from of the atypical. That's why we're in that group. The pipeline is a common carrier pipeline. Anybody can get on it. We happen to own a lot of pipeline because we're a pipeline company. Takes you to San Joaquin Valley and then takes a bus stop, gets on another pipeline and goes to our facility. If you call that jointly operated, you pretty much have the entire state jointly operated. (PHILLIPS 2)

> **Response:** ARB staff did not include the definition for “jointly operating” in the 15-Day Modifications to the Regulation.

Support for CWB Factors

B-8.12. Multiple Comments: The Coalition strongly supports staff’s proposal to adopt the CWB allocation methodology utilizing the Solomon Process Unit Factors and including Solomon’s factors for off-sites, non-energy utilities and “non-crude sensible heat.” These factors can play a very significant role in the operation of smaller, less-complex facilities and accordingly their allocation determinations. Likewise, the Coalition supports the staff proposal to not pursue additional CWB groupings. (CFEA 1, CFEA 3)

Comment: Staff is also proposing to utilize the Solomon Process Unit Factors – abandoning a previous proposal to group certain process units for alleged efficiency purposes. Staff’s presentation at the recent workshop acknowledged that product variations make the previously proposed factor groupings problematic.[49] Staff’s recent proposal also includes Solomon’s factors for “off-sites and non-energy utilities” and “non-crude sensible heat,” which were excluded under Staff’s previous proposal. Staff noted that the inclusion of those factors was supported by refineries of all levels of complexity.[50] As noted in Solomon’s August 2013 workshop presentation, calculated GHG emissions must be consistent with the capacity and throughput of process units and supporting facilities defined to calculate the appropriate CWB in any intensity metric. Failure to include these sources would result in an inaccurate reflection of true facility operation – especially for smaller, less-complex facilities like Kern because a larger percentage of its emissions are attributable to those factors. Kern believes that utilizing the Solomon factors as proposed strikes the appropriate balance between accuracy and simplicity. (KERN 1)

[49] October 7, 2013, Staff Presentation, p. 19.
[50] October 7, 2013, Staff Presentation, p. 19.

Comment: Kern is also supportive of Staff's proposal to adopt the CWB allocation methodology utilizing the Solomon Process Unit Factors and including Solomon's factors for "off-sites and non-energy utilities" and "non-crude sensible heat."[51] These factors can play a very significant role in the operation of smaller, less-complex facilities and their corresponding allocation determinations. (KERN 2)

Comment: We support the switch to the Complexity-Weighted Barrel (CWB) benchmarking methodology, but oppose additional "grouping" of CWB factors. Additionally, we support the inclusion of CWB "adjustment(s) for off-sites."

Grouping of Unit Factors: Grouping of what CARB deems similar processes does not make practical sense for a number of reasons. Grouping loses the granularity that is intentionally provided by the distinct processes in the CWB methodology and unduly sacrifices accuracy for simplicity by dismissing distinguishing details that make each refinery process unique. Indeed, refineries already have all of the data needed under the more robust CWB methodologies. The act of grouping together what may appear to be similar, but are actually very different, processes is inappropriate and may lead to misrepresentative facility CWB numbers. Grouping process units would blur the unique specificity characteristic of individual refinery operations.

Grouping further will not achieve CARB's desired outcome of incentivizing refiners to shift from higher carbon-emitting technology to lower carbon-emitting technology. Indeed, CARB's recent report on refinery energy efficiency audits did not identify technology/process equipment replacement as an opportunity for meaningful reductions. Given the context of the large scale equipment CARB proposes to group within the context of the entire refinery, actual physical replacement is realistically and financially unfeasible. Projects of this nature cost hundreds of millions of dollars to execute and provide little return on the investment with what emissions reductions might be achieved. Furthermore, the proposed grouping does not consider each process unit in the context of the entire refinery, nor that each facility's configuration and operation are based on the unique evolution of that site over time. No one unit is independent, making unrealistic this idea of simply replacing one with newer technology.

Inappropriate grouping such as what was suggested at the last workshop would penalize operations decisions that optimize energy use. The goal of any benchmarking methodology is to accurately portray actual refinery operations; therefore, CWB factors must be consistent with existing refinery operations. Grouping only serves to undermine this.

Offsites and Non-Crude Sensible Heat: We further support inclusion of CWB "adjustment(s) for offsites and non-crude sensible heat." CARB should adopt the CWB methodology as recommended by Solomon including CWB definitions and provisions

[51] Note that although smaller, less complex refineries may be able to have an accurate CWB score, infrastructure limitations prevent those refineries from ever achieving a benchmark set by performance of much larger refineries. In other words, their CWB scores cannot be fairly compared, which is why the establishment of an atypical benchmark is critical. [This concept is addressed in comments below.]

for “Offsites and Non-Energy Utilities” and “Non-Crude Sensible Heat.” As described in Solomon’s report of May 17, 2013, page 2-8 and 2-10, these are real energy demands at refineries and are therefore critical in determining appropriate allocation. Again, every refinery configuration is different, and these adjustments are necessary in portraying each refinery accurately, taking into account the full gamut of operations – beyond just the process units – that are required to make a refinery run. (CFEA 2, RCFEA 2)

Comment: Alon supports staff's proposal to adopt the CWB allocation methodology utilizing the Solomon Process Unit Factors and including Solomon's factors for "off-sites," non- energy utilities and "non-crude sensible heat." These factors can play a very significant role in the operation of smaller, less-complex facilities and accordingly their allocation determinations. Likewise, Alon supports the staff proposal to not pursue additional CWB groupings. (PARAMOUNT 1)

Comment: PHILLIPS 86 supports the inclusion of "offsite and non-energy utilities" and "non-crude sensible heat" factors in the CWB methodology. (PHILLIPS 1)

> **Response:** Thank you for the support.

Clarification of CWB Calculation

B-8.13. Comment: What adjustments are going to be included for Off-Sites and Non-Energy Utilities? What adjustments are going to be included for Non-Crude Sensible Heat? The boundary definitions and these components of a site’s Total CWB as defined by Solomon in the WSPA CWT-CWB Report, as we understand, are not in line with how CARB may proceed in using the CWB methodology. Knowing how the calculation should be done will be invaluable in helping us work through this issue. We understand that it is a possibility that a proposal will come out for the 7th, if so, we certainly need adequate time to review. (RCFEA 1)

> **Response:** CWB will be calculated using the “Off-Sites and Non-Energy Utilities” and “Non-Crude Sensible Heat” adjustments as described in Solomon Associates’ definition of CWB. The calculation is specified in the definition of CWB in section 95802(a)(66): “A refinery’s CWB value for allocation will be its CWBprocess value adjusted for off-sites and non-crude sensible heat using the following equation: CWB = 1.0085*CWBprocess + 0.327*Total Refinery Input + 0.44*Non-Crude Input. This calculation will rely on data submitted under section 95113 of the MRR, the definition of CWBprocess under section 95113(l) of MRR, and the definitions of Total Refinery Input, and Non-Crude Input given under section 95102(c) of MRR.”

Facility Non-Operation

B-8.14. Comment: Even with the inclusion of the off-site factor, the CWB methodology does not accurately reflect the emissions profile of a facility experiencing a prolonged shutdown or period of nonoperation. These emissions are necessary to keep a facility in a condition ready to produce product when market conditions demand, and to maintain and operate environmental system requirements to ensure air, water and waste regulatory compliance. Requiring an existing facility to pay for allocations under such a circumstance is a significant new and unfair cost pressure introduced as a direct result of the Program. It is a cost that could permanently shut down a facility and contribute to emissions leakage. Because the Coalition has not had sufficient time to fully work through this issue, we do not have a specific recommendation at this time. But we do request that CARB revisit this issue within the regulatory framework and work with any impacted facilities to account for just such a situation. (CFEA 1)

Even with the inclusion of the off-site factor, the CWB methodology does not accurately reflect the emissions profile of a facility experiencing a prolonged curtailment. Such a situation creates emissions associated with keeping a facility in a condition ready to produce product when market conditions demand, and to maintain and operate environmental system requirements to ensure air, water and waste regulatory compliance but is not recognized in the allocation system. This issue should be revisited within the regulatory framework and CARB Staff should work with any impacted facilities to account for just such a situation. (CFEA 3)

Asphalt refineries are directly subject to the seasonal needs associated the transportation construction industry. These seasonal variations, coupled with larger economy wide cycles require regular curtailment of operations. The current "off-site" factors do not adequately reflect the emissions profile associated with a curtained asphalt refinery. Alon requests that additional consideration be given to this issue, even if it is in a subsequent rulemaking. The emissions associated with keeping a facility in such a mode are not insignificant and should be adequately addressed in the allocation methodology. (PARAMOUNT 1)

> **Response:** ARB staff disagrees that it is appropriate to allocate to refinery facilities that are not producing product. Many industries may have costs which are not proportional to their production, but ARB staff allocates allowances in proportion to product-based benchmarks whenever such benchmarks can be calculated for the industry. The CWB factor for off-sites is intended to reflect the emissions from ancillary refinery activities, such as water treatment, which are associated with producing product. There is also a CWB factor for asphalt production.

Refinery Electricity-Related Emissions

B-8.15. Multiple Comments: Lastly, CARB also needs to appropriately define the boundary for CWB calculation purposes. (CFEA 2)

Comment: First, we commend the Air Resources Board (ARB) and the California Public Utility Commission (CPUC) for their well-coordinated efforts to develop ARB's methodologies for power allocation and CPUC's methodologies for auction revenue sharing to provide equity among EITE entities. We believe, however, that disparities exist between EITE entities serviced by the Publicly Owned Utilities (POU) depending on the extent of self-generation. We encourage ARB to work with the POU's towards equitable treatment of EITE entities within their service areas. (TESORO 1)

Comment: Self-Produced and Consumed Electricity in EITE Sectors Must Receive Auction Revenue Benefits Comparable to Grid-Electricity Consumption – ARB and California Public Utility Commission (PUC) regulations are intended to return the value of allowances allocated to electricity distribution utilities to designated classes of electricity consumers, inclusive of EITE industries that self-produce their own power. While details of such a return of allowance value to EITE industries is still under development by the PUC, what is not clear is if such revenue disbursements will be made to EITE industries in the service territories of both Investor-Owned Utilities (IOUs) and Publically-Owned Utilities (POUs). If the extent of PUC authority limits revenue disbursements to only those electricity consumers within an IOU service territory, ARB must make provisions to require the same disbursements from POUs or provide comparable allowances directly to the EITE self-producer. (APC 1)

Comment: ARB has recognized that emissions related to electricity are significant and that the allocation methodology should be equitable to EITE facilities regardless of the source of power. Many facilities generate power with on-site CHP facilities, while others purchase power from utilities or third party CHP's. However, ARB's recommended approach referred to as the "ARB Standard approach" in the October 7, 2013 workshop, does not, in and of itself, insure equitable treatment of EITE facility energy-related emissions. Rather, it relies on anticipated regulatory action by the CPUC to insure that free allocations from ARB and revenue sharing required by the CPUC meet the objective of equitable treatment and that equitable treatment is extended to facilities served by Publically Owned Utilities.

While it is clear that both ARB and the CPUC play a role in the development and implementation of the free allocation methodology, it is problematic that ARB's action will be taken before final approval of a methodology by the CPUC.

Recommendation: In order to ensure that ARB and CPUC methods are consistent with respect to treatment of power, WSPA recommends that ARB adopt a resolution that: i) allows ARB to confirm that ARB and CPUC regulations achieve the desired equitable resolution, ii) provides for reopening of ARB's allocation method if it is not resolved equitably, and iii) ensures that similar objectives are met for facilities connected to Publicly Owned Utilities. (WSPA 2)

Comment: We understand that ARB will provide allowances for direct emissions and CPUC will provide allowance value for indirect emissions. These allocations would be based on production using the same CWB benchmark. ARB discarded WSPA's recommendation to use a ratio approach to level the playing field for onsite and offsite generation based on their expectation of the CPUC's regulatory action. Due to the separation of the two agencies and time lag in the CPUC rulemaking process, we recommend that ARB adopt a resolution that recognizes this issue and would allow ARB to reopen the matter if it is not resolved equitably. (CHEVRON 1)

Comment: How would GHG emissions from onsite and self-operated CHP be handled? It appears ARB's approach provides a disincentive to the operation of onsite CHP. Refineries with onsite CHP will be held accountable for those emissions, while facilities without CHP will not have any of those emissions, but will receive credit for emissions from electricity purchases through the CWB methodology? (PHILLIPS 4)

Comment: I am also still a little fuzzy on electricity thing. We are pulling it out of emissions, so does that means that indirect emissions are now counted against the refinery? (PARAMOUNT 3)

Comment: There was a question about the indirect and electricity. Interesting to make sure that PUC and ARB, we have to look at both proposals together before we really know what's going on. (CHEVRON 5)

Comment: Will the PUC rebates be returned to all electricity producers including refineries that self-produce electricity?...

The discussion of the return of value by the CPUC is really important. It makes it hard to look at this without understanding that piece. We just want to make sure there is equity at the end of the day. I heard comments about energy efficiency, onsite electricity generation versus purchased--it is complex. I appreciate the yes-no charts, those are helpful, but maybe an example or something to that degree would be good? Different refineries, one buying power, one producing power, one selling power, how that revenue would be returned. I think that would help us to understand. (PHILLIPS 6)

Comment: One clarifying question. Someone had asked if the CPUC will give allocation value to only those people who buy power. If I'm not mistaken, ARB allocation approach is output based, so whether you buy or not, you would receive that allocation value. Is that how it would work? (EXXON)

Comment: I want to discuss the issue of electricity. As a broader construct, the PUC only has authority over investor-owned utilities and not publicly-owned utilities, so it's not clear that everyone will be treated consistently. It depends on what service district you're in or who you're covered by. The other part is, if you are only compensated for electricity you purchase and not what you produce, you will have emission associated with your onsite CHP, but you will not get any allowances as an electricity generator. So, if you're not getting any allowances as an electricity generator, and not any return of auction value, you've really created a disadvantage for CHP. So electricity produced and used internally needs to be considered. (APC 2)

Comment: I would like to go back to the concept about the onsite electricity produced being accounted for in the refinery benchmark. I agree with Steve in that the emissions for what you produce are included in what you report, but since there is not a Solomon unit factor for cogen, where exactly is it included in the CWB benchmark? (KERN 5)

Comment: So what I'm hearing is that cogen is included in emissions, but not included in the calculation of your facility-specific CWB? (KERN 4)

Comment: So it seems like someone with no CHP gets emissions credit but doesn't have emissions plus they get a rebate for any cost from buying electricity so why would anyone want to do CHP? (PHILLIPS 5)

Comment: One more question on electricity. I'm not going to get into that boundary issue. Is it the thought then, from the PUC's perspective, that when you purchase power, that the rebate will be based upon a single number regardless of the source of power? Let's say you buy power from someone who burns coal vs. natural gas with renewables, is it the same rebate per KWh, or different? (PHILLIPS 3)

Comment: On the CHP issue, under the CWB proposal. How is that different from how CHP emissions are being treated today? (SMUD 3)

Comment: Does CARB have a boundary proposal with respect to sales/production/purchases of electricity, steam and hydrogen that you can share?... We understand this is a complex issue, given the crossover with utility providers and indirect emissions from refinery-purchased electricity, but that is precisely what makes is so critical for us to fully understand. (RCFEA 1)

Comment: We have continuing technical concerns that have been raised associated with… electricity and steam. (WSPA 3)

> **Response:** ARB's standard emissions boundary was used when calculating the refinery benchmarks. For the most part, this results in equity between on-site and off-site electricity production if the Public Utilities Commission (PUC) directs investor-owned utilities to return revenue in a manner consistent with ARB allowance allocations, which they have indicated that they plan to do. ARB staff is aware that publicly owned utilities may use allowance revenue differently.
>
> The boundary for GHG emissions used to calculate the CWB and hydrogen benchmarks includes direct emissions plus emissions from imported steam, minus emissions from exported steam and electricity. This boundary is consistent with other ARB allowance allocation. Direct emissions include emissions from on-site electricity production activities, including combined heat and power (CHP). In this way, CHP is incorporated into ARB benchmarks.
>
> The amount of electricity produced and used on site does not factor directly into any refinery allowance calculations for any compliance period. Electricity generation is not an activity category that receives direct allowance allocations from ARB, whether it is conducted at a refinery or elsewhere.

Individual facility allowance allocations are proportionate to CWB and hydrogen production, irrespective of how much electricity that facility consumes and where that electricity is produced. ARB staff anticipates that PUC may take a similar approach when directing investor-owned utilities to return allowance revenue to refineries in the second and third compliance periods. Such an approach would be consistent with PUC's product-based allocation methodology, described in their July 10, 2013 staff proposal. As noted in that proposal, together, ARB and PUC allocation methodologies for refineries would then result in equitable treatment of individual refineries and of the refining sector with respect to CHP.

The above discussion applies to refineries that are customers of investor-owned electricity utilities. ARB staff is aware that publicly-owned utilities may make different decisions regarding how they use electricity-related allowances they receive. This is the result of the current regulatory structure including policies of publicly-owned utilities as well as ARB and PUC. ARB staff is not considering amendments to change ARB-controlled aspects of this regulatory structure in ways that would affect only refineries or any other individual sector.

As part of existing ARB Regulation, all electrical distribution utilities are required to report to ARB how they use the value of the free allowances they receive. ARB staff is also in close communication with PUC regarding the use of allowance value, and does not see a need for a formal resolution on the topic at this time.

B-8.16. Comment: We would like to see ARB's case studies for treatment of imported electricity to ensure that results will be equitable in all cases. (CHEVRON 1)

Response: ARB staff has evaluated this request and determined that these case studies should not be released. ARB staff is willing to share any facility's imported electricity data with them; however, ARB staff is not able to share one facility's confidential business information with another facility.

Special Treatment for Equipment Changes

B-8.17. Comment: Second, we would like to request recognition of the early reduction projects such as the Tesoro Golden Eagle Coker Modification Project within the Complexity Weighted Barrel (CWB) benchmark method. In 2008 Tesoro implemented its Coker Modification Project (CMP) at the Golden Eagle Refinery near Martinez, California, that resulted in early reductions of greenhouse gases and other pollutants. GHG emission reductions from the project were 462,000 tonnes/yr based on the third party verified emission reports. The project was the largest single emission reduction measure reported for the refining sector in the Energy Efficiency and Co-Benefits Assessments and resulted in reductions of overall energy use, criteria pollutants and air toxic emissions. The project did not change production at the Golden Eagle Refinery. The emission reductions are real, permanent and verifiable.

Tesoro presented information to ARB staff demonstrating that as a result of project implementation, CWB, the proxy adopted for refinery sector output, is disproportionally reduced relative to refinery production. The Tesoro's CMP project replaced the existing fluid coking process with a delayed coking process which is a less carbon intensive process. Consequently, the CWB factor for delayed coking, which is lower than the factor for fluid coking, would be used in calculating allowance allocation for the second and third compliance period. This regulatory approach stifles innovation and reduces incentives to implement an alternate process to reduce multiple pollutants. Instead, the proposed regulation only serves to encourage an entity to continue to operate the same inefficient unit and to either purchase credits or install control equipment (if technology exists) for a single pollutant.

We recognize that the development of a refinery benchmarking method has been a difficult task. In many instances, changes in refinery operations may result in corresponding changes to refinery production. However, this is not the case for Tesoro's CMP project for which the refinery has continued to retain its capacity to produce clean California fuels. To ensure equitable treatment we request that ARB allows the use of a CWB factor for fluid coking in determining allocation for Tesoro's Golden Eagle refinery coking process.

The current regulatory approach that results in a reduction in allocations to a facility because it adopts a less carbon intensive process resulting in multiple pollutant reductions is contrary to the objectives of AB32. In fact, ARB recognized the need to provide incentives in choosing an allocation methodology for the first compliance period by considering an allowance allocation based on the operation of the fluid coking process. Therefore, we are requesting that the same treatment continues into the second and third compliance period. To accomplish this, we suggest that ARB provide a mechanism for Executive Officer review of projects that adopt less carbon intensive operations and ensure that allocations are not inequitably reduced as a result of the proxy chosen to represent refinery output. We would expect such review to be supported by a thorough analysis of emissions, unit operations, and production. We believe this proposal is consistent with the objectives of AB-32. (TESORO 1)

> **Response:** The Cap-and-Trade Program is designed such that early investments in emissions-reducing technologies are rewarded by a decrease in a compliance obligation. Given the fact that other regulations necessitated the project, and given the costs of the CMP project, ARB staff believes that the benefits Tesoro has already received are sufficient. There are many refineries in California that use delayed cokers. Going forward, it would be inequitable for Tesoro to continue to use the fluid coking CWB factor for its delayed coker while other refineries which installed delayed cokers earlier are required to use the delayed coking CWB factor, which is lower.

Checking Calculation of CWB for Individual Refineries

B-8.18. Multiple Comments: We ask that you clarify back to companies, your numbers with the companies that submitted data in the next few weeks would be great. We think feedback to companies would be great.…

I just want to reiterate, you took in a lot of great data, so thank you. I just want to make sure we need to be on the same page with the data and calculations. How you calculated the CWB for each facility in each year. You should review data with each company so that everyone can do the math. We would encourage that dialogue. (PHILLIPS 3)

Comment: That would be helpful. Validate the company data you used with the company that submitted the data. Just to confirm that the same numbers were used, etc. There is not a confidentiality issue with confirming the information. (APC 2)

> **Response:** ARB staff agrees with the suggestion and met with every covered entity refinery and confirmed their CWB data. Many refineries provided new data to ARB during the course of this data checking. ARB staff is confident that the data it used for benchmarking match what each refinery has provided.

Refinery True-Up for First Compliance Period Allocation Methodology

B-8.19. Multiple Comments: Alon is concerned that staff is proposing to make unidentified changes to the current true-up language where there has been a decrease in production. Alon believes that any new changes in the true-up provisions must be coupled with recognition that facilities may have emissions without having proportional CWB production. As we discussed in our introduction Alon is in the process of reconfiguring its West Coast assets, these unspecified changes could have a significant impact on Alon and similar situated entities. These "clarifications" have never mentioned or discussed in any of the staff's previous notices on this rulemaking package. Alon believes that fundamental fairness requires businesses be given a full comment period to review and comment on any staff proposals. Moreover, Alon believes that under the APA any such changes must go through a full comment period since they were never mentioned or discussed in any of the staff's previous notices on this rulemaking package. (PARAMOUNT 1)

Comment: The Proposed Regulation no longer materially amends section 95891(d)(2), facilities with an EII. What was CARB's rationale for not pursuing this proposed amendment from the Discussion Draft? (RCFEA 1)

> **Response:** ARB staff proposed changes in the 45-Day Modifications to the Regulation to include a true-up for non-EII refineries that received allowance allocation based on the production of primary refinery products. This aligned this product-based allocation methodology with all other product-based allocation, which include true-up mechanisms to match allocation with production for each calendar year. ARB staff proposed changes to section 95891(d)(2) in the 15-Day Modifications to the Regulation.

B-8.20. Comment: ARB proposed amendments contain several discrepancies in the terminologies used in various equations related to true-up requirements that prevents proper calculations of true-ups and second and third compliance period allocations. In order to facilitate ARB review, WSPA has identified specific issues and made individual recommendations.

FIRST COMPLIANCE PERIOD TRUE-UP

Section §95891(d)(2)(B) as revised defines the process for "trueing debt" as follows: *"TrueUp Debit. If actual 2013 and 2014 emissions are less than the amount of allowances allocated, the entity will need to surrender additional allowances according to the following equation:*

$$TrueUp_{Y,Debit} = 0.8 * [(AE_{Y,2013} + AE_{Y,2014}) – (A_{Y,2013} + A_{Y,2014})]$$

Where:
"$AE_{Y,t}$" = Actual GHG emissions from a facility in year "t" adjusted for heat sales and purchases and electricity sales

"$TrueUp_{Y,Debit}$" = the amount true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations for refinery "Y". This value of allowances for budget year "t" shall be allowed to be used for budget year "t-2" pursuant to 95856 (h)(1)(D) and 95856 (h)(2)(D).

<u>Issue:</u> The problem with this section is the inconsistent use of year "t" in the two definitions above. Under "$AE_{Y,t}$", the year "t" is intended to be 2013 and 2014, while year "t" under "$TrueUp_{Y,Debit}$" is intended to represent 2015. If the proposed language is left unchanged, year t-2 under the "$TrueUp_{Y,Debit}$" definition may be misconstrue as years 2011 and 2012.

Recommendation: We recommend clarifying §95891 (d)(2)(B) and changes to the definition $AE_{Y,t}$ as follows:

§95891(d)(2)(B): TrueUp Debit. If actual 2013 and 2014 emissions are less than the amount of allowances allocated, the entity will need to surrender additional allowances <u>to meet the first compliance period triannual compliance obligation</u> according to the following equation:

If: $(AE_{y,2013} + AE_{y,2014}) < (A_{y,2013} + A_{y,2014})$

Then, $TrueUp_{Y,Debit} = 0.8 * [(AE_{Y,2013} + AE_{Y,2014}) – (A_{Y,2013} + A_{Y,2014})]$

Where:

~~*"$AE_{Y,t}$" = Actual GHG emissions from a facility in year "t" adjusted for heat sales and purchases and electricity sales*~~

<u>*"$AE_{Y,2013}$" = Actual GHG emissions from a facility in year "2013" adjusted for heat sales and purchases and electricity sales*</u>
<u>*"$AE_{Y,2014}$" = Actual GHG emissions from a facility in year "2014" adjusted for heat sales and purchases and electricity sales. (WSPA 1)*</u>

Response: ARB staff proposed changes in the 15-Day Modifications to the Regulation that clarified that the allocation of true-up allowances for EII refineries would occur in 2015 with budget year 2016 allowances.

B-8.21. SECOND AND THIRD COMPLIANCE PERIOD TRUE-UP

For the allocation equation in S95891 (b):

$$A_t = (\sum O_{a,t-2} * B_a * AF_{a,t} * C_{a,t}) + TrueUP_t$$

In this section, $TrueUp_t$ is defined and calculated as follows:

"$trueup_t$" is the amount of true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations. This value of allowances for budget year "t" shall be allowed to be used for budget year "t-2" pursuant to 95856 (h)(1)(D) and 95856 (h)(2)(D). This value is calculated using the following formula:

$$TrueUp_t = (\sum O_{a,t-2} * B_a * AF_{a,t-2} * C_{a,t-2}) + A_{t-2,no\ trueup}$$

It appears that the intent of the allocation equation is to include both true up debit and true up credit in the determination of the annual allocation. However, the true up formula in this section contradicts the formulas for true up debit "$TrueUp_{Y,Debit}$" and true up credit "$TrueUp_{Y,Credit}$" specified for facilities with an EII value for the first compliance period as described in S95891(d)(2)(B) and (C).

<u>Issue:</u> §95891(d)(2)(B) and (C) already specified true up formulas for facilities with an EII which are not the same as the true up formula in this section 95891 (b). Furthermore, true up debit and true up credit are calculated differently. Consequently, the $TrueUP_t$ value in the allowance budget year 2015 and 2016 for facilities with EII should follow the approach in §95891(d)(2)(B) and (C).

Recommendation: To ensure consistency throughout the regulation, we recommend revising the definition "$trueup_t$" in the regulation be as follows:

"$trueup_t$" is the amount of true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations. This value of allowances for budget year "t" shall be allowed to be used for budget year "t-2" pursuant to 95856 (h)(1)(D) and 95856 (h)(2)(D). <u>Except for budget</u>

year 2015 and 2016 for facilities with EII, ~~*T*~~*this value is calculated using the following formula:*

$TrueUp_t = (\sum O_{a,t-2} * B_a * AF_{a,t-2} * C_{a,t-2}) + A_{t-2,no\ trueup}$

Where:

$O_{a,t-2}$ …………………………..

$A_{t-2,no\ trueup}$ ………………..………

$AF_{a,t-2}$ ……………………………….

$C_{a,t-2}$ ……………………..…...

For budget year 2015, $TrueUP_t$ for facilities with EII, is equal to $TrueUp_{Y,Debit}$ or $TrueUp_{Y,credit}$ *pursuant to 95891 (d)(2)(B) and 95891 (d)(2)(C). This value of allowances for budget year 2015 shall be allowed to be used for budget year 2013 and 2014 pursuant to 95856 (h)(2)(D).*

For budget year 2016, $TrueUP_t$ for facilities with EII, is equal to zero. (WSPA 1)

Response: Petroleum refinery true-up allowances for data years 2013 and 2014 are provided for under section 95891(d) of the Regulation, not under 95891(b). In 2014, all petroleum refineries will be allocated budget year 2015 allowances pursuant to section 95891(b) and reported and verified CWB data, and non-EII petroleum refineries will be allocated budget year 2015 true-up allowances pursuant to 95891(d) using reported and verified emissions and primary refinery product data. In 2015, all petroleum refineries will be allocated budget year 2016 allowances pursuant to section 95891(b) and reported and verified CWB data, non-EII petroleum refineries will be allocated budget year 2016 true-allowances pursuant to 95891(d) using reported and verified emissions and primary refinery product data, and EII petroleum refineries will be allocated budget year 2016 true-up allowances pursuant to 95891(d) using reported and verified emissions data.

October Workshop Presentation Questions and Comments

B-8.22. Multiple Comments: In the interest of transparency, the calculation method used to allocate allowances based on the refinery benchmark must be made public. Attempts to duplicate the overall calculation method (not for individual facilities) used by ARB have failed. Specifically, the CWB benchmark for 2014 should provide 84.96% (0.944 cap * 0.9 stringency) allowances based on the 2014 cap stringency and the 10% “haircut” policy. ARB stated at the workshop that their proposed benchmark would provide only 83% when using the CWT index. Converting CWT to CWB should yield the same percentage reduction.

Recommendation: ARB should release the calculation method so that stakeholders understand the process and data used in the analysis. (WSPA 2)

Comment: We are concerned that the analysis presented on October 7 showed that the CWB benchmark for 2014 will not provide the expected 84.5% (0.944 cap * 0.9

stringency) allowances, but rather provides only 83%. We would like to review ARB's methodology for calculating the refinery benchmark, particularly with respect to the details of how hydrogen plants were treated. (CHEVRON 1)

Comment: Thank you, we definitely notice some changes since August. I just wanted to clarify on Slide [12]. It says net impact is 85%, is that the net impact for 2015 including both cap decline and benchmark stringency? Or is the benchmark so stringent that it's only 85 or 83% of the obligation? (CHEVRON 5)

> **Response:** This comment was not submitted in accordance with the procedure provided in either the 45-day or 15-day public comment notices. It was instead provided verbally during a workshop – not conducted by the Board as part of the noticed hearing process – that occurred during the 45-day comment period. Therefore, ARB staff does not believe a response is required. However, in the interest of completeness, ARB staff responds as follows. The commenter refers to slides presented during the workshop. ARB staff understands these to be the slides available here: http://www.arb.ca.gov/cc/capandtrade/meetings/100713/refinery_workshop_presentation_10_7_13.pdf
>
> ARB staff used its standard benchmark calculation methods and cap decline stringency to propose a CWB benchmark in the 15-Day Modifications. This includes use of the 0.944 cap stringency for 2014 and 90% or best in class approach, as appropriate, to calculate benchmark values. Including the cap decline results in the 85% stringency mentioned by the commenter.
>
> The 83% that commenters have identified refers to CWB, not CWT. As part of the workshop presentation, ARB staff presented an analysis comparing CWT and CWB. In this context, a hypothetical CWB benchmark was calculated using data from all refineries and merchant hydrogen plants. Applying this benchmark would result in allocation of 83% of refineries' but not merchant hydrogen's total allowance obligation. The 85% value for CWT was calculated using a hypothetical CWT benchmark based on data from refineries but not merchant hydrogen plants, because CWT requires hydrogen plant input which was not available for merchant hydrogen.

B-8.23. Multiple Comments: [These comments were not submitted in accordance with the procedure provided in either the 45-day or 15-day public comment notices. They were instead provided verbally during a workshop – not conducted by the Board as part of the noticed hearing process – that occurred during the 45-day comment period. Therefore, ARB staff does not believe a response is required. However, in the interest of completeness, ARB staff responds as follows. These commenters refer to slides presented during the workshop. ARB staff understands these to be the slides available here: http://www.arb.ca.gov/cc/capandtrade/meetings/100713/refinery_workshop_presentation_10_7_13.pdf]

We have lots of technical questions on the use of data, starting with Slide 9. Can you comment about the data used, number of data points, dates of the data collection, breadth of data used?...

I'm not clear on the "CWB=0.8476" times emissions comment. What are you conveying here?...

When you say CWB, what do you include in that number? (PHILLIPS 3)

Comment: I also have a regression question. My question is specifically on the offsites. We have one refinery that has shut down, and we have emissions when we're shut down, so we know that the regression line will not go through the origin. There is a constant left over. Did you try to run the regression with the constant and force it to go through the origin? (PARAMOUNT 3)

Comment: When you calculated the emissions, I assume you subtracted the steam and power as you've already described, but did you then subtract the hydrogen that was reported in the survey? (TESORO 2)

> **Response:** The regression was calculated by ARB staff using California refinery data. CWB were calculated by ARB staff as defined in MRR, plus hydrogen CWB, minus the adjustments for off-sites. Also note that the underlying data have been updated since October 2013, based on additional analyses by ARB staff and ongoing discussion with all California refineries that are covered entities. Refinery survey data for 2008 and 2010 were used to calculate CWB, and the 2008 and 2010 CWB values for each refinery were averaged before performing the regression. Emissions in the benchmark were calculated as direct emissions minus emissions from exported steam and electricity, plus emissions from imported steam, using data reported under the Mandatory Reporting Regulation. Hydrogen emissions were not subtracted. The emissions intensity used for electricity was 0.431 metric tons CO_2 equivalent per kilowatt-hour and for steam was 0.6244 metric tons CO_2 equivalent per million Btu, as is used for energy-based allowance allocation.
>
> When calculating the regression, the constant was forced to be zero in order to represent that all emissions are attributed to CWB. ARB staff has conducted various analyses, including other regressions which are not presented in the interests of brevity and protection of confidential information. Since ARB staff allocates in proportion to CWB, this seemed to be the most relevant analysis to present. This regression reflects the relationship between CWB and emissions, including the high R^2 that shows that CWB is a good predictor of GHG emissions.

B-8.24. Multiple Comments: [These comments were not submitted in accordance with the procedure provided in either the 45-day or 15-day public comment notices. They were instead provided verbally during a workshop – not conducted by the Board as part of the noticed hearing process – that occurred during the 45-day comment period. Therefore, ARB staff does not believe a response is required. However, in the interest of completeness, ARB staff responds as follows. These commenters refer to slides presented during the workshop. ARB staff understands these to be the slides available here: http://www.arb.ca.gov/cc/capandtrade/meetings/100713/refinery_workshop_presentation_10_7_13.pdf]

I just have a data question. You said you used 2008 and 2010 survey data (slide 9), are those the same two years that are incorporated in the other graphs that are included?

So, on Slide 17 where you have a benchmark curve, and you have a single data point for each facility, can you tell us how you came up with a single data point for each? Did you take their 2008/2010 value and average them?...

Why did you not use 2009 and 2011 survey data, since we submitted 4 years of data to you? (KERN 5)

Comment: I am trying to understand a little more about Slide 17 data, and how does it translate to the slide previous and if it does? You note that you average data for 2008 and 2010. What would happen if you did a scatter of all the data and not average? Would that have changed the graph?...

Let's say the shape of the curve remains but you have more points? Would that changes any of slide 16? Does slide 17 inform slide 16? (WSPA 4)

> **Response:** ARB staff believes the commenter is referring to the benchmark curve (i.e., emissions divided by CWB) for each of the 17 refinery covered entities. Note that the CWB calculations used in the October 7, 2013 workshop differ from the way CWB will be calculated for the purposes of allocation.
>
> The initial refinery survey requested data for each year in 2008 through 2011. However, many refineries objected that data for 2009 and 2011 were difficult to report because Solomon Associates does not collect data during those years. Many refineries did not submit data for 2009 and 2011 and ARB staff did not insist on this data, judging that 2008 and 2010 would suffice. All California refineries submitted sufficient data to calculate their CWB values for 2008 and 2010. For most other industrial sectors benchmarks are set using the average of 2008, 2009 and 2010 data.
>
> ARB staff is unclear on what the commenter is asking regarding the shape of the curve, but clearly refinery emissions per CWB are likely to vary somewhat from year to year, so that would be reflected if 2008 and 2010 data were shown separately. ARB staff cannot comment extensively on this given the confidential nature of the data.

B-8.25. Multiple Comments: [These comments were not submitted in accordance with the procedure provided in either the 45-day or 15-day public comment notices. They were instead provided verbally during a workshop – not conducted by the Board as part of the noticed hearing process – that occurred during the 45-day comment period. Therefore, ARB staff does not believe a response is required. However, in the interest of completeness, ARB staff responds as follows. One commenter refers to slides presented during the workshop. ARB staff understands these to be the slides available here: http://www.arb.ca.gov/cc/capandtrade/meetings/100713/refinery_workshop_presentation_10_7_13.pdf]

A few questions to bring up on Slide 17. Data is everything in how this is managed. If you then took each refinery and plotted them, then I guess these data point represent the average of their 2008/2010 numbers. When you calculate the benchmark, is it volume weighted? You did not take the arithmetic average of these 10-13 data points then?...

I would raise the question as to whether this is equitable. There are two ways to do it: volume weighting is one way, but taking the arithmetic average is another. So I think you will receive some comments on that since it raises a key equity issue. (PHILLIPS 6)

Comment: As far as volume vs. arithmetic average, when you're talking about the other sectors, you say you do this for everybody. What is the standard deviation between entities in other sectors? I bet that it is higher for refineries and it wouldn't apply in this case…

Can you outline the standard deviation for all sectors. I want to see it documented, since I don't believe the calculations are correct. (PHILLIPS 6)

> **Response:** The proposed benchmark, like all ARB output-based benchmarks, is volume-weighted. This approach weights all units of production equally, regardless of whether they were produced by a large or small facility.
>
> The sectors covered by the Cap-and-Trade Regulation vary in the standard deviation of their emissions intensity. ARB staff has not released such data because they could reveal confidential business information.

Hydrogen Allocation

Calculation Basis of the Hydrogen Gas Benchmark

B-8.26. Comment: Perhaps you can help explain a discrepancy I am seeing in my use of the CWB factors….

The May 17th “Report on CWT-CWB for California Regulatory Support”, prepared for WSPA by Solomon Associates includes CWB factors for hydrogen production.

For example, in Appendix C (pg C-3), the CWB factor for Steam Methane Reforming production of hydrogen is 5.70 CWB/k SCF of hydrogen. Appendix G indicates these units are “1,000 standard cubic feet”… but I am thinking this should be “million standard cubic feet”… here is my thinking…

[Reference CARB 10/7/13 Workshop Slides] You have proposed a benchmark factor, derived from the available subset of the production plants in the state, of 20 allowances per million standard cubic feet. [Slide 34]

If I were to calculate a comparable hydrogen benchmark value using the CWB factor, I would expect it to be generally similar to the 20 allowances/million SCF CARB proposed.

Where has CARB also determined the refinery CWB benchmark, based on 90% of the refinery sector average intensity, of 4.03 allowances/CWB. [Slide 16]
… when I take 5.70 CWB per 1000 SCF * 4.08 allowances/CWB = 23.3 allowances/1,000 SCF…. off by a factor of 1000 (versus 20 allowances/1,000,000 SCF).

Can you explain this discrepancy? I suspect this is because CARB is describing CWB factors as based on “…1,000’s of barrels per year for most process units” [Slide 16] and all the CWB factors in the WSPA/Solomon report are based on just barrels, so all the CWB factors would actually be reduced by 1000. Have I got this confused? (RAPC 3)

Response: This comment was not submitted in accordance with the procedure provided in either the 45-day or 15-day public comment notices. It was instead provided to ARB staff via email – not as part of the noticed hearing process – during the 45-day comment period. Therefore, ARB staff does not believe a response is required. However, in the interest of completeness, ARB staff responds as follows. The commenter refers to slides presented during the October 7, 2013 refinery workshop. ARB staff understands these to be the slides available here:
http://www.arb.ca.gov/cc/capandtrade/meetings/100713/refinery_workshop_presentation_10_7_13.pdf

Hydrogen production will not be included in the CWB benchmark; a separate hydrogen benchmark was proposed in the 15-Day Modifications. For those units included under CWB, ARB staff measures them in the units specified in Table 1 of MRR. In most cases, these units are in thousands of raw units per year, whereas Solomon Associates used raw units per calendar day when calculating CWB factors. For example, most process units are to be reported in thousands of barrels per year under Mandatory Reporting, whereas Solomon Associates considered them in barrels per calendar day. If hydrogen were included in CWB, the units would be millions of standard cubic feet (mscf) per year, since the Solomon Associates units are thousands of standard cubic feet per calendar day (k SCF/cd). When calculating a potential allowance allocation under the Cap-and-Trade Regulation, the units specified in the Mandatory Reporting Regulation should be used to be consistent with ARB calculations. Since the CWB factors are all scaled to the emissions intensity of an atmospheric distillation unit, which therefore has the CWB factor of 1, this difference in units does not affect most CWB factors—that is, ARB staff can use the same values for the CWB factors that Solomon Associates provided. Where the change in units does matter, ARB staff has made the necessary adjustments to CWB factors.

B-8.27. Multiple Comments: PHILLIPS 66 opposes the "staff thinking" proposal to establish a separate Hydrogen benchmark outside of the CWB methodology. PHILLIPS 66 supports the comments submitted by the Western States Petroleum Association on this issue. (PHILLIPS 1)

Comment: ARB proposes to apply the “best in class” benchmark that was developed for the six merchant hydrogen plants to all internal refinery hydrogen plants, without adjustment or changes. Treating facilities with similar functions as identical does not represent the best technical or feasible approach…...Requiring refineries to put a virtual ‘fence’ for purposes of monitoring and benchmarking between the integrated hydrogen plant and all of the other processes in the refinery is technically inequitable, infeasible and not necessary given the robust CWB methodology proposed for the rest of the refinery. Hydrogen plants that are internal to refineries should not be segregated from the refinery for the purpose of benchmarking; instead, a refinery should be benchmarked for all the process units within its boundaries.

Benchmarking merchant and internal hydrogen plants together is technically inequitable to the refineries with internal hydrogen plants.

- Merchant plants are newer and have the advantage of utilizing newer technology. These plants were built after 1994 and all use the pressure swing absorption technology, which inherently has fewer emissions.
- The Solomon methodology under CWB recognizes that refinery hydrogen plants are integrated into the refinery. Therefore including hydrogen plants within the refinery benchmark as a whole provides a fair allocation of allowances to hydrogen units.
- MRR CWB rules do not require metering of steam, electricity and other systems between process units. If the internal hydrogen plants are benchmarked separately these systems may not be monitored or metered to a level required by the Mandatory Reporting Rules. It would be difficult to monitor the emissions due solely to hydrogen production because hydrogen units inside a refinery share steam and other utilities with the rest of the refinery; these transfers are not monitored in the same way that they would be with a merchant hydrogen unit.

Merchant plants meter their outputs in order to transact their contracts with the refineries.

- Please see Attachment 1 for more details on differences between hydrogen plants embedded in refineries and merchant hydrogen plants.
- The proposed merchant hydrogen benchmark of 20 allowances/mscf for the hydrogen plant sector is not appropriate for benchmarking internal refinery hydrogen plants.
- he currently proposed benchmark for hydrogen plants is based on 'best in class', and was developed to represent a benchmark for 6 merchant hydrogen plants. This is not an appropriate benchmark for the 18 hydrogen plants in California, many of which have a different design than the 'best in class' plant.
- Creating a hydrogen benchmark that is based on the most efficient merchant hydrogen unit is an unrealistic benchmark for hydrogen units within a refinery. Hydrogen units within the refinery are integrated into the refinery operations. A refinery might have optimized their hydrogen plant for additional steam rather than making steam elsewhere in the refinery; thus the hydrogen production would be lower and the emissions of their hydrogen unit would be higher than if the plant stood alone.

Having two separate hydrogen benchmarks would be the most equitable solution with the least additional study and equipment.

A revised joint hydrogen plant benchmark could not be developed within ARB's timeframe to meet regulatory deadlines for MRR. An attempt to calculate a separate benchmark that would include refinery and merchant hydrogen plants would be very difficult, since as described above, refinery hydrogen plants are closely integrated into the refinery, making it difficult to accurately assess and allocate emissions to the hydrogen plant. Substantial new data would be needed to correctly develop a technically sound benchmark. Many of the imports and exports into internal refinery hydrogen plants and the hydrogen and steam balance are not monitored at MRR level basis. Studies and equipment would be needed to obtain that data prior to creating a fair representative benchmark.

- ARB has created additional benchmarks when one benchmark is not representative or one group is substantially disadvantaged by the benchmark. ARB pointed out in the workshop that merchant plants are sufficiently different than hydrogen plants inside refineries such that merchant plants would receive as much as 20% more allowances under the CWB. This would be an indication that the two groups are significantly different in design and therefore demonstrates the justification two benchmarks.
- We recommend using the existing hydrogen plant benchmark of 20 allowances/mscf for merchant hydrogen plants and allowing internal hydrogen plants to be given allowances under the CWB benchmark with the rest of the refinery processes.
- If one benchmark is ARB's only answer, then merchant plants and internal hydrogen plants could benchmark based on CWB.

- This concept avoids trying to artificially separate integrated systems and would reward merchant systems for their efficiency. We cannot comment on the benchmark for merchant hydrogen plants, but the general practice of using 'best in class' instead of 90% of average appears to be creating an unnecessary and inequitable penalty for these operators and leads one to question why the Solomon CWB factor was not used as a basis for the merchant hydrogen benchmark.

In conclusion, we recommend that ARB include internal refinery hydrogen plants in the CWB benchmark for refining based on the technical and policy reasons described above. We recommend that ARB implement this change by including the CWB factor for hydrogen plants in the CWB table and specify that 'mscf' refers to net million standard cubic feet of hydrogen production…

Attachment 1

Detailed Comments on Differences between Embedded and Merchant Hydrogen Plants
The benchmark for the refining sector should be used for the whole refinery for the following reasons:

1. The CWB approach to refinery benchmarking is based on emission intensity of worldwide refining operations. In order to equitably develop and apply a CWB-based benchmark to California refineries, all of the process units in each refinery (including hydrogen units) should be included in the benchmark for the refining sector, and in each refinery's CWB calculation.
2. The CA-CWB factors for hydrogen plants express emission intensity of worldwide hydrogen plants relative to atmospheric crude distillation; including feedstock conversion to hydrogen, fuel for the reforming furnace, imports or exports of thermal energy across unit boundaries, and power. These factors should continue to be used in calculating total CWB for a refinery.
3. Onsite hydrogen plants represent a broader range of technologies than merchant hydrogen plants. ARB should recognize that the inventory of on-site hydrogen plants, both worldwide and in California, includes various technologies for hydrogen production. All of the merchant plants in California utilize the "new" PSA technology.
4. Accounting for emissions in on-site hydrogen plants is less straightforward than in merchant hydrogen plants.
    a. Feedstocks for on-site hydrogen plants are metered and reported under the MRR, but fuel metering for the MRR may, in some cases, be metered upstream and include emission sources in other units. Feedstock and fuel for off-site hydrogen plants are normally supported by financial transaction meters.
    b. Imports and exports of thermal energy between a hydrogen plant and the rest of the refinery can include multiple levels of steam (e.g., high pressure, medium pressure, low pressure), steam to drive condensing or letdown turbines, low pressure steam from letdown turbines, and boiler feedwater (deaerated and/or preheated). Steam may also be used

internally for the regeneration of a CO2 absorbing solvent used to purify the hydrogen. The utility balance is an important part of the equation in determining the net energy use and net emissions profile for any given hydrogen plant, but the data and analysis required to support the utility balance for an on-site hydrogen plant normally requires some degree of manual readings and engineering estimates.

   c. The CWB factor for SMR (steam methane reforming) hydrogen plants is consistent with natural gas feed and fuel. In practice, SMR hydrogen plants process both heavier feeds (containing ethane, propane, butane, etc.) and lighter hydrogen-rich feeds. Because of this, specific and equally efficient plants may have higher or lower emissions relative to the CWB factor and benchmark.

5. The proposed benchmark for refining, with hydrogen plants addressed separately, may be inequitable. Carving out hydrogen plants from the refinery CWB could potentially be inequitable to the refining sector unless the reduction in CWB, benchmark emissions, and allocations are exactly equal to the addition of benchmark emissions and allocation resulting from hydrogen operations. This analysis would need to include factors for offsites and non-energy utilities and sensible heat of non-crude feeds as well as consistent treatment of thermal energy and power. If the reduction in CWB is not offset by an equal increase associated with hydrogen operations, ARB is effectively applying a stricter stringency factor (more stringent than 90%) than that used for other sectors.
6. ARB stated that the policy goal of treating hydrogen separately were:
   a. Consistent incentives between on-site and off-site hydrogen production
   b. Avoiding over-allocation to off-site hydrogen that would occur if off-site hydrogen were allocated using CWB

To meet both of these goals, ARB has proposed a more stringent benchmark for hydrogen that appears to be consistent with the most efficient state-of-the art plants. This in turn results in a stricter stringency standard for refining as a whole. This is a departure from the intent of using the Solomon factors, supported by broad international experience, for the benchmarking of refinery units. (CHEVRON 1)

Comment: One Product – One Benchmark Principle Maintained – Air Products strongly supports ARB's continued commitment to the principle of defining a single benchmark value for each distinct product – regardless of the many variations in practice (process, feedstock, facility ownership, etc.). This issue has been a particular concern for industrial gas companies which produce hydrogen and must receive an allowance allocation equal to that which would be received by a refinery producing the same quantity of hydrogen product to prevent distorting the marketplace.

The "one product-one benchmark" program design principle has been repeatedly recognized by CARB and was clearly noted in the 28 August 2013 staff presentation (slide 25) when noting that the "Allocation should be independent of ownership structure" and the 7 October 2013 staff presentation (slide 31) when noting "Consistent incentives between on-site and off-site hydrogen production" is a specific CARB policy goal.

While adherence to this program design principle has been achieved by the current proposal where a common allocation benchmark of 20 allowances/mscf hydrogen applies to both on-site and off-site hydrogen production, we believe alternative allocation approaches, including sharing a common CWB factor and benchmark, would also satisfy the "one product – one benchmark" principle. Air Products reinforces CARB's commitment to this outcome in any revision to the allocation methodology for hydrogen production.

6. Currently Proposed Hydrogen Benchmark is Not Representative of Actual Production Facilities in California; Benchmark Must be Revised to Represent Total Population of Hydrogen Production Plants - Air Products marketing research indicates there are 27 "on purpose" gaseous hydrogen production plants in California. However, CARB's current hydrogen production benchmark proposal was derived from only 5-7 "merchant" plants (industrial gas company- owned), a small subset consisting of the newer and more efficient hydrogen production facilities in the state. The result is a benchmark that is biased to a lower value, and therefore not representative of the entire hydrogen production sector.

A proper benchmark would be derived from the performance curve of all 27 gaseous hydrogen production facilities in the state, calculated consistent with the methodology employed in the determination of all other product benchmarks. This may require supplementing the data obtained through Mandatory Reporting Rule (MRR), particularly for the on-purpose hydrogen production conducted within refineries. CARB can make a formal data request to fill any data gaps in hydrogen-specific emissions, corrected for steam export, and accounting for only the "on purpose" hydrogen production. [Note: The performance curve for this benchmark derivation would purposefully exclude the performance data of the two liquid hydrogen plants in California; Air Products continues to propose a separate benchmark value for liquid hydrogen production, as discussed below.]

The benchmark derivation must determine the actual average emission intensity, and then determine the greater of "90% of that average" or the "best of class" of the sector value. The average emission intensity determination can be represented by:

Average Hydrogen Emission Intensity

$$\frac{\sum_{n=0}^{27}(Total\ Hydrogen\ Plant\ Emissions - Export\ Steam\ Emissions - Export\ Power\ Emissions)_n}{\sum_{n=0}^{27}(On - Purpose\ Hydrogen\ Produced)_n}$$

CARB has stated that is does not have a complete data set for the refinery on-site hydrogen facilities, preventing them from making a determination as noted above. If such a determination directly from California-specific facilities is not feasible, an alternative is to use the Carbon Weighted Barrel (CWB) approach – again for both off-site and on-site hydrogen plants.

7. CWB Methodology Could be Employed as an Alternative Approach for the Hydrogen Benchmark – Absent the complete and accurate data set of hydrogen plant emissions and production to derive the correct California-specific hydrogen benchmark, the CWB methodology can be employed to yield a benchmark that is representative of the full population of hydrogen production facilities in the state. This will require treating both refinery on-site and industrial gas company off-site hydrogen production as a CWB production activity, using the CWB values developed by Solomon from the OECD refinery database (e.g. 5.70 CWB/ k scf of SMR-produced hydrogen[52]), and applying a recalculated CWB Benchmark value. Such an approach maintains the "one product – one benchmark" principal, more accurately describes the benchmark curve of gaseous hydrogen production, and avoids redundant allocation of allowances.

While not perfect, use of a common CWB methodology would have the following features:

- The CWB hydrogen factors derived by Solomon from data of approximately 200 OECD refineries represent an un-biased characterization of gaseous hydrogen production – covering a wide range of facility ages, technologies and sizes of plants – more closely reflecting the diversity of California's full 27-plant population. This eliminates the bias of the currently proposed benchmark resulting from using data of the small subset of generally newer and more efficient, off-site hydrogen plants.
- Would properly include the emissions from raising steam consumed by the refinery in the benchmark calculation while not assigning a production activity (e.g. CWBs) to steam production – consistent with the overall CWB methodology.
- Would properly exclude the emissions from raising steam which is exported from the refinery, as well as while not assigning a production activity (e.g. CWBs) to steam production – consistent with the overall CWB methodology.
- Would properly exclude the emissions from generating electricity while not assigning a production activity (e.g. CWBs) to electricity generation.
- Would not over-allocate allowances to merchant hydrogen plants. Consistent with all other product-based benchmark development, a benchmark curve should show a distribution of plants – some with efficiency better than their sector average and some with efficiency worse than their sector average. Presuming the benchmark value is set at 90% of that sector average, it is still common that the most efficient plant(s) may receive an allowance allocation approaching their emission compliance obligation, while the least efficient plants may fall well short of their compliance obligation. It is not a flaw, but rather a positive design feature, that a benchmark rewards those entities which made early investments in more efficient process designs and operating methods.
- Would maintain a consistent incentive between on-site and off-site hydrogen production… and all other emission reducing activities. The "cost of carbon", as informed by the market prices of California Compliance Allowances and

[52] Solomon Associates, "Report on CWT-CWB for California Regulatory Support", 17 May 2013, page C-3.

California Compliance Offsets, ensures there is an equal incentive to increase efficiency for all producers, regardless of ownership.

Applying the CWB approach to hydrogen production is comparable to combining the refining and hydrogen sectors… where the benchmark includes the combined sum of both their emissions (with appropriate steam and electricity production adjustments) and the combined sum of both their CWB production activity.

The benchmark derivation must determine the actual average emission intensity, and then determine the greater of “90% of that average” or the “best of class” of the sector value. The average emission intensity determination for the combined refining and hydrogen sector can be represented by:

Average Combined Refining and Hydrogen Emission Intensity

$$\frac{\sum_{n=0}^{n}(Adjusted\ Refinery\ CO2\ Emissions)_n + \sum_{y=0}^{y}(Adjusted\ OffSite\ H2\ Plant\ CO2\ Emissions)_y}{\sum_{n=0}^{n}(Refinery\ CWB\ Production)_n + \sum_{y=0}^{y}(OffSite\ H2\ Plant\ CWB\ Production)_y}$$

Where Adjusted Refinery CO2 Emissions =

$$Total\ Refinery\ CO2\ Emissions - Refinery\ Export\ Steam\ CO2\ Emissions - Refinery\ Electricity\ Generation\ CO2\ Emissions$$

And, Adjusted Offsite Hydrogen Plant Emissions =

$$Total\ Offsite\ H2\ CO2\ Emissions – Offsite\ H2\ Export\ Steam\ CO2\ Emissions – Offsite\ H2\ Electricity\ Generation\ CO2\ Emissions$$

Export Steam CO2 Emission and Electricity Generation CO2 Emissions can be determined from actual operating/emission data, if available, or estimated using CARB’s default Energy-Use Benchmark and Co-generation Emission Distribution values.

And, Refinery CWB Production =

$$"Process\ CWB" + "Off - Sites\ and\ Non - Energy\ Utilities" + "Non - Crude\ Sensible\ Heat"$$

And, Offsite H2 CWB Production =

$$Offsite\ H2\ \text{Process CWB} + OffsiteH2\ "Off - sites\ and\ Non - Energy\ Utilities" + Offsite\ H2\ "Non - Crude\ Sensible\ Heat"$$

Where “Process CWB”, “Off-sites and Non-Energy Utilities” and “Non-Crude Sensible Heat” are as defined in Solomon Report.[53] For Offsite Hydrogen “Process CWB”, the CWB factor is 5.70 CWB/k scf. The “Total Input Barrels” and “Non-Crude Input Barrels” terms in the “Off-sites and Non-Energy Utilities” and “Non-Crude Sensible Heat” calculations represent the Fuel Oil Equivalent Barrel[54] of the Offsite Hydrogen Plant feedstock natural gas.

[53] Solomon Associates, “Report on CWT-CWB for California Regulatory Support”, 17 May 2013, page 2-10.
[54] Solomon Associates, “Report on CWT-CWB for California Regulatory Support”, 17 May 2013, Appendix G, page G-2.

In this manner, all of the relevant emissions from all refining and hydrogen production, and all CWB production from all refining and hydrogen production are included in their respective numerator and denominator to define the combined sector average. (APC 1)

Comment: In the October 7, 2013 workshop, ARB proposed that on-site hydrogen plants be removed from the refinery allocation methodology and that on-site and off-site hydrogen plants be benchmarked based on the same benchmark applied to the merchant hydrogen facilities. WSPA believes it is inappropriate to benchmark based on the merchant facilities because they represent a minority of the hydrogen production[55] in California and exclusively use Pressure Swing Adsorption which is the most current and efficient approach for hydrogen purification. This contrasts with On-site (refinery) hydrogen facilities in California and elsewhere in the world which utilize both PSA and Solvent technology. Use of a single benchmark representing broad industry practice that includes refineries and merchant plants rather than from use of a small subset of operators will result in a more equitable benchmark to facilities in the State.

> **Recommendation:** WSPA recommends utilizing the CWB methodology for refinery benchmarking because it is appropriate for California operations. Moreover, because it was developed through years of experience with over 200 refineries worldwide, use of the methodology ensures that refineries are equitably represented. If this approach is chosen by ARB for both on-site and off-site production it would meet ARB's first goal, as stated in the workshop, of providing consistent incentives for efficient operation of hydrogen plants.

A more detailed description of the background on hydrogen plant operations is provided as Attachment A…

Attachment A: Treatment of Hydrogen Plants and Hydrogen Plant Benchmarking
The benchmark for hydrogen plants should be based on all hydrogen plant operations in California. Specifically, the benchmark should include facilities that are associated with refinery operations and independent "merchant" plants that sell hydrogen to refineries.

This "inclusive" approach would represent that greatest number of facilities and therefore is the most representative of the overall breadth of hydrogen plant operations. The inclusive approach would also result in the "fairest" and most equitable benchmark for the reasons detailed below.

The CA-CWB factors for hydrogen plants express emission intensity of worldwide hydrogen plants relative to atmospheric crude distillation; including feedstock conversion to hydrogen, fuel for the reforming furnace, imports or exports of thermal energy across unit boundaries and power. These factors should continue to be used in

[55] "Hydrogen Generation" means a unit producing hydrogen. Steam Methane Reforming, includes units producing hydrogen from steam reforming of natural gas or refinery gases. Steam Naphtha Reforming includes units producing hydrogen from steam reforming of naphtha. Partial Oxidation Units produce steam from partial oxidation of fuel oil. The primary product is hydrogen. Low btu gas or Carbon Dioxide are byproducts of these plants. The CWB factors for hydrogen purification units, such as Cryogenic Unit, Membrane Separation Unit, and Pressure Swing Adsorption (PSA) unit, as well as U71 (CO Shift & H2 Purification) and U72 (POX Syngas for H2 Generation), are allocated among Hydrogen Generation units.

calculating total CWB for a refinery. ARB should recognize that the inventory of on-site hydrogen plants, both worldwide and in California, includes various technologies.

Feedstocks for on-site hydrogen plants are metered and reported under the MRR, but fuel metering for the MRR may, in some cases, be metered upstream and include emission sources in other units. Feedstocks and fuel for off-site hydrogen plants are normally supported by financial transaction meters. Hence, because some hydrogen plant metering may not exactly match MRR requirements, only an "inclusive" approach that includes all hydrogen plants will be consistent with the approach used by ARB for all other facilities.

Imports and exports of thermal energy between a hydrogen plant and the rest of the refinery can include multiple levels of steam (e.g., High pressure, medium pressure, low pressure), steam to drive condensing or letdown turbines, low pressure steam from letdown turbines, and boiler feedwater (de-aerated and/or preheated). The utility balance is an important part of the equation in determining the net energy use and net emissions profile for any given hydrogen plant, but the data and analysis required to support the utility balance for an on-site hydrogen plant normally requires some degree of manual readings and engineering estimates. The CWB factor for steam methane reforming (SMR) hydrogen plants is consistent with natural gas feed and fuel. In practice, SMR hydrogen plants process both heavier feeds (containing ethane, propane, butane, etc.) and lighter hydrogen rich feeds. Because of this, equally efficient plants may have varying (i.e. higher or lower) emissions relative to the CWB factor and benchmark.

In contrast to the "inclusive" process, excluding hydrogen plants from the refinery CWB could potentially be inequitable to refineries unless the supporting analysis provides assurance that the reduction in CWB, benchmark emissions, and allocations are exactly equal to the addition of benchmark emissions and allocation resulting from hydrogen operations. Such equality is at this time difficult to prove and may not be supported by metering as described above[56]. If the reduction in CWB is not offset by an equal increase associated with hydrogen operations, then ARB would be effectively applying a stricter and inequitable stringency factor (more stringent than 90%) than that used for other sectors.

We understand that the policy goal of treating hydrogen separately was to provide consistent incentives between on-site and off-site hydrogen production and to avoid over-allocation to off- site hydrogen that would occur if off-site hydrogen were allocated using CWB. To meet both of these goals ARB has proposed a more stringent benchmark for hydrogen that appears to be consistent only with the most efficient merchant plants. This approach would be a significant departure from the intent of using the Solomon factors, supported by broad international experience, for the benchmarking of refinery units. This is so because hydrogen units within the refinery are integrated into refinery operations. For example, a refinery may choose to have its

[56] As stated earlier, a detailed analysis to support an exclusive approach would need to include factors for offsites and non-energy utilities and sensible heat of non-crude feeds as well as consistent treatment of thermal energy and power

hydrogen unit make extra steam rather than making steam elsewhere in the refinery. In such an instance, the emission of their hydrogen unit might be higher than if the plant stood alone. (WSPA 2)

Comment: We are still trying to understand the use of the merchant hydrogen benchmark. All of the other benchmarks were set using all of the facilities. Averaging them, and then setting your benchmark based on the current policy. You do have all the hydrogen emissions data and the hydrogen throughput data (from MRR and survey respectively) so I am confused as to why you would not use all the data you have. I am not sure you can approximate an embedded hydrogen plant compared to an external hydrogen plant that is merchant, but I do think you have the data. We are concerned about how steam would be handled, and I think refinery group will ask you to look at that. Why did you not use the data that you have?...

Initially we had testified during the August workshop (last year) with Ecofys report, we were concerned about comparing embedded hydrogen plants within a refinery to third party hydrogen plants. At that point we were opposed, and we would need to understand your proposal here, which we don't. This is brand new. But on the basic principle, this is not how you have set the other industrial benchmarks. I don't know where we currently stand on this; certainly a year ago we were opposed to it. (CHEVRON 4)

Comment: We point out that gaseous hydrogen benchmark is based on merchant facilities. Wonder why since they represent less than 1/3 of the industry capacity in the state and represent newer, more efficient facilities in the industry. We are concerned that ARB has built a benchmark based on a subset of facilities, thereby building in a bias [against?] the newer facilities. We feel this is not the intent of the benchmarking… There is also a Solomon factor for hydrogen, why are you not using it? (APC 2)

Comment: Why was the benchmark based on the newest/largest hydrogen plants in the state instead of the full population of hydrogen plants? Do you expect the refineries to replace their existing hydrogen plants with new merchant type/size plants to manage their compliance costs? (PHILLIPS 4)

Comment: At the [October 7] workshop, CARB staff stated CARB's intention to depart from the CWB approach for hydrogen production. Instead, CARB proposed a benchmark based on the emissions of the six third-party hydrogen production facilities in the state. That benchmark—20 allowances per million standard cubic feet ("mmscf") of hydrogen produced—is equivalent to approximately 8.48 tonnes C02e/tonne H2, and is lower than the previous benchmark of 8.85 tonnes C02e/tonne H2. Emissions from the 20 refinery-owned hydrogen production facilities were not considered in developing this proposed benchmark.

Air Liquide supports CARB's proposal to use a uniform benchmark for both refinery-owned and third-party hydrogen production facilities, and does not object in principle to CARB's proposal to develop a separate, non-CWB benchmark for the hydrogen production sector. However, any such benchmark must be based on emissions from all 26 hydrogen production facilities in California. The six third-party hydrogen plants whose emissions are the basis for the proposed 20 allowances/mmscf benchmark are among the most efficient hydrogen producers in the state. CARB's proposal would punish the hydrogen production sector because of the investments made at these plants to increase efficiency and reduce greenhouse gas emissions. The Cap and Trade Program is intended to reward, not punish, such investment.

CARB's proposal is also inconsistent with its treatment of other industries. For most products, CARB has adopted a benchmark based on 90 percent of industry average emissions or emissions of the "best in class" facility, whichever is greater. (Cap-and-Trade Regulation, Notice of Public Availability of Additional Documents (July 2011), App. Bat 3-4.) Basing the hydrogen production benchmark on a small, unrepresentative subset of the most efficient hydrogen production facilities in California is inconsistent with CARB's stated policy.

Thus, while Air Liquide supports CARB's decision to develop a uniform benchmark that applies to both third-party and refinery-owned hydrogen plants and does not object to developing a benchmark using a non-CWB methodology, we urge CARB to revise the proposed hydrogen production benchmark to account for the emissions intensity of the entire hydrogen production sector, and not just a selective, unrepresentative subset of the sector. The revised benchmark should be based on the emissions of all 26 hydrogen production facilities in the state, including both third-party and refinery-owned facilities. (RLIQUIDE 2)

Comment: Consistent with the representations I made in my statement at the workshop last week, in our formal comments submitted Monday, and in discussions with staff over the past several years, the “Off-site” hydrogen plants are materially newer (and we can reasonably infer that translates to more modern and efficient technology) than the “On-site” hydrogen plants. Taking into account the range that results when considering how to assess a couple of plants that have had some revamp subsequent to their original on-stream date, the average age of the “On-site” plants is 32-34 years old; the average age of the “Off-site” plants is 15 years old.

I believe this helps support our contention that a benchmark derived exclusively from “Off-site” plant performance is biased against all hydrogen production. [The commenter provided information on California hydrogen production facilities that cannot be reproduced in this document.] (RAPC 4)

Comment: We have continuing technical concerns that have been raised associated with hydrogen plant, the treatment of a hydrogen plant... (WSPA 3)

> **Response:** ARB staff agrees that it is preferable to use both refinery and merchant hydrogen data to calculate a single benchmark for hydrogen. Data which ARB staff received on hydrogen production at refineries are now sufficiently thorough that staff was able to use them to calculate a hydrogen gas benchmark

that incorporates both refinery and merchant data. For reasons mentioned by several commenters, ARB staff believes that it is important to give the same benchmark to refinery hydrogen and merchant hydrogen. Refinery hydrogen plants and merchant hydrogen plants serving refineries are providing the same product to the same industry, and thus fall under the "one product, one benchmark" principle. Because they provide the same product, it would be inequitable to assign different benchmarks based on process design or ownership.

ARB staff considered three main options for calculating the hydrogen benchmark: using CWB, using only merchant hydrogen data, or using both refinery hydrogen and merchant hydrogen Mandatory Reporting Regulation data.

ARB staff calculated a potential CWB-based hydrogen benchmark using data from all refineries and merchant hydrogen facilities. However, the design of CWB probably overestimates the emissions due to hydrogen production relative to most other refinery processes. This is because, when Solomon Associates created the CWB factors, they assumed that natural gas was the fuel source for all refinery activities, which results in overestimation of process emissions relative to fuel-based emissions. Also, because the data used to create CWB factors are only from Solomon Associates clients, they are likely to exclude most merchant hydrogen data and may not be representative of hydrogen production in California.

As some commenters mentioned, some refinery hydrogen plants may produce more steam than necessary for hydrogen production, and therefore have higher emissions than if they produced a minimal amount of steam. In fact, this effect may have caused the hydrogen benchmark to be higher than it would be if ARB staff had full data on refinery hydrogen steam and electricity production and use. However, this effect would also result in a lower CWB benchmark because refinery hydrogen emissions were subtracted from emissions used to calculate the CWB benchmark. Therefore, ARB staff believes that the net effect is reasonable given the data available.

Hydrogen Gas Benchmark Calculation

B-8.28. Comment: How will GHG emissions from hydrogen plants operated by and within a refinery be handled? Will the CWB credit for hydrogen be excluded from the refinery CWB calculation? (PHILLIPS 4)

Response: Hydrogen will not be included in the CWB calculation. If a refinery produces hydrogen, it will receive CWB allocation calculated based on its reported and verified CWB data and the CWB benchmark plus hydrogen gas allocation calculated based on its hydrogen gas production and the hydrogen gas benchmark.

B-8.29. Multiple Comments: The benchmark is million standard cubic feet. We ask that ARB define that. There are different definitions in the industry (with temperature as well). (APC 2)

Comment: I'm working with the Air Liquide guys to better understand your hydrogen benchmark proposal and put together our comments. It would be helpful if we could understand what years data you used to calculate the benchmark (i.e., 2010-2012, 2008, etc?) as well as what methodology you used (i.e., did you average them and do the 90 percent hair cut, did you take the raw average, etc.?). (RLIQUIDE 1)

Comment: So that's whats is inside [the emissions boundary for] the refinery benchmark, which may not be what is in the hydrogen benchmark? (APC 2)

Comment: What are the base years for the determination of the refinery and hydrogen benchmarks? What is the source of data for the hydrogen benchmark?
To what extent is this data going to be made public – in the manner that the refinery benchmark curve has been shown in the presentation. (RAPC 1)

Comment: In light of the disclosure today that the benchmark data for hydrogen is just from the Merchant sub-group, I would not want the raw data publically disclosed, as it discloses confidential information between the only other large-scale merchant producer (Air Liquide) and ourselves (yet another reason to have the database be inclusive of ALL hydrogen production units in the state). (RAPC 2)

> **Response:** The hydrogen benchmark was calculated using 2008 and 2010 merchant hydrogen and refinery hydrogen data. These data years are used for consistency with the years used to calculate the refinery benchmark. The benchmark was calculated as 90% of sector-wide emissions per metric ton of hydrogen. Prior to calculating the benchmark, merchant hydrogen emissions were adjusted to include emissions from imported steam and exclude emissions from exported steam and electricity. No such adjustment was made for refinery hydrogen data because the necessary steam and electricity data were not available.
>
> Refinery hydrogen data are from the refinery survey, while merchant hydrogen data are from MRR records. A small number of facilities had problems with hydrogen production emissions data reported in the voluntary survey, and both production and emissions data from these facilities were excluded from the calculation.
>
> In the 15-Day Modifications to the Regulation, staff proposed a hydrogen gas benchmark in units of metric tons of on-purpose hydrogen gas to avoid the ambiguity concern raised by a commenter. Million standard cubic feet (scf) were previously considered because they are the units of 2008 and 2010 MRR data used to calculate the benchmark. The conversion used was 2.408 metric tons per mscf, which assumes atmospheric pressure and 60 °F.

Clarifying Definition of Hydrogen Gas Produced (for Allocation Purposes)

B-8.30. Multiple Comments: I have a question on pulling out hydrogen. We have a refinery with two sources of hydrogen, one from a reformer and one from a hydrogen plant. So, you would consider the hydrogen from the reformer as separate and distinct, right? (PARAMOUNT 3)

Comment: The reporting rule explicitly looks for hydrogen produced on purpose. It should be the stand alone hydrogen volume, and then the incidentally produced hydrogen, from something like a reformer, should be handled separately as part of CWB process. So, I respectfully disagree with how you answered that question. Let's make sure we're clear about what the reporting rule says. (APC 2)

> **Response:** The benchmark for gaseous hydrogen production was calculated based on the total amount of molecular hydrogen leaving the purifier after the hydrogen production unit, excluding any hydrogen that bypassed the hydrogen production unit. This quantity includes gaseous hydrogen regardless if it was formed in the hydrogen production unit or formed in a different process unit. Future allowance allocations will be calculated based on this definition of on-purpose hydrogen gas.

Liquid Hydrogen Benchmark

B-8.31. Multiple Comments: The Benchmark for Liquid Hydrogen Should be Derived from Just the Specialty Plants that Produce Liquid Hydrogen — A separate benchmark should be derived for the production of liquid hydrogen, accounting for the inherent structural differences in the design of production facilities for this product versus gaseous hydrogen production used for refinery application. A benchmark can be derived from historical performance data from the two liquid hydrogen plants in California.

The market for liquid hydrogen product requires plants be designed at a scale consistent with market demand. Further, plant location will typically be dictated by customer locations and utility pricing (as opposed to gaseous hydrogen plants which are co-located with a "base-load" refinery customer). As such, liquid hydrogen plants do not incorporate the energy integration and heat recovery that is standard in gaseous hydrogen plant designs, reducing the inherent efficiency of the liquid plants.

Air Products recommends the liquid hydrogen plants be treated as a separate sector when setting the allocation benchmark. This is analogous to CARB's proposed separate treatment of "Atypical Refineries" versus "Typical Refineries". Referencing the 7 October 2013 Workshop slides, comparable considerations are:

- Liquid hydrogen plants occupy the far tight-hand side of a Benchmark Curve (CARB issued a preliminary benchmark curve for off-site hydrogen production in

June 2011), after a recognizable break in the slope of the curve – comparable to the position the Atypical Refineries occupy on the refinery CWB Benchmark Curve (Slide 17).

- Steam methane reformers serving liquid hydrogen facilities are markedly smaller process units which have less process recycle, crude product recovery and heat integration – comparable to the differences highlighted for Atypical Refineries (Slide 25).
- Liquid hydrogen production facilities represent a disproportionately small fraction of total emissions from hydrogen production – comparable to the emissions fraction attributed to the Atypical Refineries (slide 26).

A proper liquid hydrogen benchmark would be derived from the performance data of the two dedicated liquid hydrogen production facilities in the state. This may require supplementing the data obtained through the Mandatory Reporting Rule (MRR). CARB can make a formal data request to fill any data gaps in liquid hydrogen-specific emissions and production. (APC 1)

Comment: As discussed below, Praxair requests that the Air Resources Board ("ARB") continue to evaluate the emissions benchmark specified in Table 9-1 for liquefied hydrogen. Liquefied hydrogen is a unique and distinct product from gaseous hydrogen and ARB's regulations should explicitly recognize that differentiation.
In the initial release of the draft Cap-and-Trade Regulations several years ago, no distinction was made between liquefied hydrogen and gaseous hydrogen. After several meetings and numerous phone conversations between Praxair and ARB staff, the two categories were ultimately recognized as having significant differences that warranted separate allocations. The final Cap-and-Trade Regulation (adopted in 2011) purposefully established a distinction between liquefied and gaseous hydrogen products, but assigned the same benchmark value to both products: 8.85 Allowances I metric ton (See Table 9-1). During the rulemaking, staff said this distinction was made to enable reconsideration of technical details with respect to production (e.g., efficiency factors) that may result in different allowance assignments for the two products. Based on recent meetings between Praxair and ARB, it was our understanding that an allocation for liquefied hydrogen would be based on the two liquid hydrogen facilities located in California. Given this course of communications, it is puzzling to us that ARB has gone full circle back to the initial draft position that liquefied hydrogen and gaseous hydrogen should have the same benchmark, since none of the underlying assumptions have changed. As discussed below, there are numerous structural differences between liquefied and gaseous hydrogen plants serving refineries. The products are also handled and reported differently. ARB should consider the products separate and distinct from one another and develop a benchmark that is specific to liquefied hydrogen plants in California, consistent with ARB's practice in developing benchmarks in other sectors.

DISCUSSION

During the October 7 Workshop, ARB proposed to give liquid hydrogen the same emissions benchmark as gaseous hydrogen because "liquid hydrogen direct GHG emissions come primarily from producing hydrogen, not from condensing it to liquid", and "therefore it is equitable to provide the same benchmark."[57] Praxair is concerned by this proposal because it diverges from ARB's practice of setting a benchmark that at least one facility in California could meet. Despite all of the ongoing energy efficiency investments, Praxair's Ontario facility would not be able to meet the gaseous hydrogen benchmark. As a result, California's liquefied hydrogen industry will face greater domestic leakage risks, which will tend to increase GHG emissions due to transportation of the product from out-of-state sources.

While liquefied hydrogen is a more electricity intensive product than gaseous hydrogen, there are also greater direct emissions attributable to liquefied hydrogen due to three general structural differences between liquefied and gaseous hydrogen plants. These structural differences are akin to the distinction ARB intends to make between "atypical" and "typical" refineries. First, hydrogen plants manufacturing liquefied product are smaller than plants producing gaseous hydrogen for use by refineries. Liquefied hydrogen plants are sized to meet the regional market demands for liquefied hydrogen. As such, liquefied hydrogen plants are typically 5- 10% of the size of gaseous hydrogen plants serving refineries. Moreover, due to the predictable demand of refineries, gaseous hydrogen plants typically operate closer to their nameplate capacities, resulting in higher operating efficiencies. Liquefied hydrogen plants have less consistent demand, meaning they cannot consistently achieve the same operating efficiencies as gaseous hydrogen plants serving refineries. Thus, due to the completely different customers and demands for their products, liquefied and gaseous hydrogen plants have different GHG emissions intensities.

Second, there are differences in energy intensities of liquefied and gaseous hydrogen plants serving refineries. Liquefied hydrogen plants do not incorporate the same heat recovery technologies that are typically used by the large gaseous hydrogen plants designed to meet the more predictable and steady demands of refineries. Gaseous hydrogen plants are able to market waste steam for various applications in the refinery, whereas liquefied hydrogen plants do not have customers for their waste steam.

Liquefied hydrogen plants also have a higher "heat leak unit value" (i.e., how much heat is lost per MT of hydrogen produced). This is because less hydrogen is produced compared to large refineries and liquefied hydrogen plants do not achieve the same operating efficiencies as gaseous hydrogen plants.

Third, liquefied hydrogen plants are structurally different due to the purity requirements for creating liquefied hydrogen. To produce liquefied hydrogen, the hydrogen feedstock from a Steam Methane Reformer ("SMR") must be purified to 10 ppm. By comparison, SMR's that serve refineries only have to have a purity of 1,000 ppm. To achieve the higher purity for liquefaction, the filtering process disposes of both hydrogen and

[57] See Slide 33 from ARB's October 7 2013 Workshop, available at:
http://www.arb.ca.gov/cc/ca pandtrade/meetingsll 00713/refinery workshop presentation 10 7 13.pdf

impurities together. The impact of purifying the hydrogen is the loss of approximately 5.6% of the molecules created in the reforming process. This reduced volume of hydrogen increases the CO_2 emissions per unit of hydrogen produced.

Liquefied hydrogen is also a separate and distinct product from gaseous hydrogen due to the handling of liquefied hydrogen after liquefaction, the scope of potential customers, and the manner in which distribution occurs. These distinctions are important because the new Mandatory Reporting Requirements direct liquefied hydrogen producers to report the quantity sold to customers. Since this information will be the basis for allocations, the development of a liquefied hydrogen benchmark must account for the quantity of product sold to customers.

Gaseous hydrogen is typically consumed close to the gaseous hydrogen production facility (such as in a refinery setting) and there are minimal commodity losses between what is produced and what is delivered to customers. On the other hand, there are commodity losses associated with the handling and delivery of liquefied hydrogen. Liquefied hydrogen is transported by truck and there can be losses due to the distance traveled, elevation, temperature and other factors. Since liquefied hydrogen producers must report the volumes sold to their customers under the Mandatory Reporting Regulation (and this information will be the basis for the allowance allocation), the liquefied hydrogen benchmarks must account for the delivered product. Developing a benchmark that is consistent with the reporting requirements is necessary to ensure that liquefied hydrogen is treated consistently with other Emissions Intensive Trade Exposed industries (e.g., glass manufacturing).

Praxair requests that ARB recognize the distinctions between gaseous and liquefied hydrogen and develop an appropriate benchmark for liquefied hydrogen that is consistent with ARB's analysis for other products. ARB should base the liquefied hydrogen benchmark on the best-in-class facility in California, or average the emissions intensities of the California facilities and then multiply the average by a 90% efficiency factor. (PRAXAIR)

Comment: We are concerned about combining the benchmarks for gaseous and liquefied hydrogen. We point out that Staff originally considered them as separate products, and Praxair continues to support this methodology. We reason that liquid hydrogen facilities are about 10% size of gaseous hydrogen facilities. As a result, the scale of production for liquid production is going to be much higher as they have relatively more emissions per unit of production.

We are concerned that if there is not a separate benchmark, you will be deviating from the methodology used in all other sectors (i.e., 90% or best in class). We are concerned that with proposed methodology, there is no way that a facility in CA could meet the benchmark. which will lead to leakage since liquid hydrogen is so easy to transport across state lines. We urge ARB to take a second look...

Our second concern is that liquefied hydrogen can be trucked easily and therefore is open to domestic leakage. We are interested to see how ARB will continue to evaluate leakage risk domestically. (PRAXAIR 2)

Comment: Also, maybe liquid and gaseous hydrogen should have different benchmarks. We want this clear prior to the PUC process. (APC 2)

Comment: Have you given any consideration to the "structural difference" between the liquid hydrogen vs. gaseous hydrogen plants, analogous to the different consideration/benchmark proposed for the "atypical" refineries? (RAPC 1)

Comment: As it relates to LHY, there really is a structural issue when producing the gaseous hydrogen at that scale to subsequently liquefy – like an "atypical" refinery; such plants are not designed with the degree of energy integration that allows larger plants to be significantly more efficient. I believe the analogy can be relevant. (RAPC 2)

> **Response:** ARB staff agrees that liquid hydrogen is a distinct product from hydrogen gas, and proposed a separate benchmark for liquid hydrogen in the 15-Day Modifications to the Regulation. ARB staff concluded that liquid hydrogen is fundamentally a different product from gaseous hydrogen because it has different characteristics (including purity) and is used for different purposes. Therefore, it is appropriate for liquid hydrogen to receive a separately calculated benchmark.
>
> It is worth noting that several of the arguments given by commenters are not viewed by ARB staff as reasons for separate benchmarks. Within a sector, some facilities may be less efficient due to smaller size, age of equipment or ability to integrate heat with other processes. ARB does not set benchmarks based on these characteristics.
>
> ARB acknowledges the commenters' concerns regarding liquid hydrogen emissions leakage. ARB is committed to monitoring this issue and making adjustments to minimize leakage, as appropriate.

Coke Calcining

B-8.32. Multiple Comments: We are also not clear on why CARB has not yet designated coke calcining as an industrial operation with greater than 50% process emissions. Our coke calciner clearly meets this criteria. PHILLIPS 86 has provided supporting information as to why calciners should be added to Table 9-2 where other "Process with Greater than 50% Emissions" industries are listed and assigned an appropriate cap reduction factor.

CARB staff has also suggested that part of this evaluation is evaluating calcining's risk as EITE (Energy Intensive, Trade Exposed) industry. In this review, we do not understand CARB's rationale for designating calcining as part of a three digit NAICS code that covers all petroleum products, when there is a objective six digit custom description for Calcining (NAICS Code 324199) found in the Emission Intensity Table K-10. CARB is arbitrarily recommending a more general code that would result in our Calciner failing to qualify for the alternative and appropriate cap adjustment factor. Table K-10 in Appendix K has a listing of Emission Intensities. The calciner NAICS code 324199 indicates an intensity of 9,754 which is greater than the necessary threshold for the 50% process emission declining cap factor of 5,000 MT/$M. If there is uncertainty in the industries included in the original survey P66 can provide ARB with the necessary information to further support an emissions intensity >5,000 MT/$M. (PHILLIPS 1)

Comment: Also, changing topics to calciners. I also have a two part issue: 1 is the Benchmark and 2 is the Cap decline factor. Was the decision made on the cap decline factor, since it's not in the proposal? (CFEA 7)

> **Response:** This comment is not responsive to the proposed modifications.

B-8.33. Comment: PHILLIPS 66 opposes the adoption of the newly introduced and unjustified Calciner benchmark. We were surprised by seeing it the October 7th Workshop PowerPoint without any supporting data or discussion.

Unfortunately, there has not been opportunity to understand and review CARB's underlying data and assumptions, which eliminates our company ability to participate in this rulemaking.

There are only two calciners in the state making this decision poor public policy and one that is still unanswered by CARB. As part of the further discussions, we will want to discuss and understand the basis for the current and proposed benchmarks, confirm that the metrics of the benchmark are understood and identify possible technology and operational differences in the two Calciners operating in California. (PHILLIPS 1)

> **Response:** A new calciner benchmark was proposed in the 15-Day Modifications to the Regulation, and was calculated based on historical data from both calciners in California, using the 90% or best in class approach that is the ARB standard for calculating benchmarks. The emissions and production data necessary to the benchmark calculation were voluntarily provided by these calciners. The proposed benchmark value is 68% higher than the value in the current Regulation.

Mandatory Reporting Regulation

B-8.34. Multiple Comments: Process unit definitions that are too specific risk confusion and problems during verification and may require ongoing changes as new technology is developed. ARB can ease this issue by clearly listing these definitions under CWB and prefacing them as "intended for the purpose of guiding the calculation of CWB."

While we understand the need for a core description, there are also dangers in specific lists of feeds and products. If a specific definition does not include all possibilities, the verifier may not be able to match a process unit directly to its definition. We recommend that broader language in these areas be included in each of the definitions. For example, “feeds include but are not limited to…” and “products include but are not limited to…”

We suggest that ARB either adopt the process unit definitions provided by WSPA, since these adhere more closely to the definitions provided by Solomon in Appendix D of their May 17, 2013 document or defer all but the largest process unit definitions to guidance. If ARB does not use the Solomon definitions provided by WSPA, the changes outlined in Attachment 2 are necessary.

In addition to the issues raised above, Chevron has the following comments on other, less significant issues, which should be addressed by ARB nonetheless.

- Fuel gas sales and treating should be reported in hp, not hp/yr as shown in the proposed table of CWB Values. This factor is based on the size of the equipment, not how much it was actually used during the year. This is a reasonable simplification, since the CWB factor incorporates an assumed utilization based on Solomon’s global data regarding refinery operations.
- Sulfur production should be reported in long tons not light tons. A light ton is not a recognized unit of measure.
- There are a few process units where the feed to one unit is NOT reported separately but is combined with another unit. For example, ‘tail gas recovery unit’ is already included in the sulfur recovery unit and should not be reported again—this is not explicitly in the May 17 document but was stated elsewhere by Solomon. The whole definition seems to be missing from the list provided by ARB on October 7.
- The footnotes to Appendix D of the May 17 document are not precisely included in ARB definitions.
    - The first footnote is about lubricants. ARB did not include the lubricants section from definitions in the May 17 document but instead broke out each of the lubricant processes. It would be preferable to include the lubricants as shown in the definitions.
    - The footnote about hydrogen plants should be included, and there should be a definition of ‘hydrogen plant.’ (CHEVRON 1)

Comment: [This comment is reproduced here using the same formatting as the original submission.]

Language to Support Complexity Weighted Barrel (CWB)

<u>To the equation for CWB, the CWB functions for Offsites and Non-energy utilities and Non Crude Sensible Heat need to be added.</u>

Page 2 (E) Add, …….CWB function, however it is recognized that total process CWB, total input, and total non-crude input are used to calculate CWB for “off-sites and non-energy utilities” and “not crude sensible heat.”

Page 6 – Units for sulfur recovery should be “thousands of long tons/year”

Page 8 – Units for Fuel Gas Sales Treating and Compression (hp) should be hp, not hp/year

Definitions
“Complexity weighted barrel” or “CWB” means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes. The CWB value for an individual refinery is calculated using actual refinery throughput to specified process units and emission factors for these process units. The emission factor is denoted as the CWB factor and is representative of the greenhouse gas emission intensity at an average level of energy efficiency, for the same standard fuel type for each process unit for production, and for average process emissions of the process units across a sample of refineries. Each CWB factor is expressed as a value weighted relative to atmospheric crude distillation.
Process Definitions

- “Air separation unit” means a refinery unit which separates air into its components including oxygen. It is usually cryogenic but factor applies to all processes cryogenic or otherwise.
- “Alkylation/poly/dimersol” means a range of processes transforming C3/C4/C5 molecules into gasoline ~~C7/C8 molecules~~ over an acidic catalyst. This can be accomplished by alkylation with sulfuric acid or hydrofluoric acid, polymerization with a C3 or C3/C4 olefin feed, or dimersol.
- “Ammonia recovery unit” means a refinery unit in which ammonia-rich sour water stripper overhead is treated to separate ammonia suitable for sales or reuse in the refinery, in particular for the reduction of NOx emissions. This unit is the second stage of a two stage sour water stripping unit. The ammonia recovery unit includes, but is not limited to, the adsorber, stripper and fractionator.
- “Aromatic saturation of distillates” means the saturation of aromatic rings over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. ~~This process includes the desulfurization step which should therefore not be accounted for separately.~~
- “AROMAX®” means a special application of catalytic reforming for the specific purpose of producing light aromatics.
- “Aromatics production” means extraction of light aromatics from reformate and/or hydrotreated pyrolysis gasoline by means of a solvent.
- “Asphalt production” means the processing required to produce asphalts and bitumen, including bitumen oxidation (mostly for road paving). Asphalt later modified with polymers is included.

- "Atmospheric Crude Distillation" means primary atmospheric distillation of crude oil and other feedstocks. The atmospheric crude distillation unit includes any ancillary equipment such as a crude desalter, naphtha splitting, gas plant and
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wet treatment of light streams for mercaptan removal. Some units may have more than one main distillation column.
- "Benzene saturation" means selective hydrogenation of benzene in gasoline streams over a fixed catalyst bed at moderate pressure.
- "C4 isomer production" means conversion of normal butane into isobutane over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure.
- "C5/C6 isomer production - including ISOSIV" means conversion of normal paraffins into isoparaffins over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure. ~~Throughputs of this unit include the throughput of both once-through and recycle units.~~
- "Conventional naphtha hydrotreating" means desulfurization of virgin and cracked naphthas over a fixed catalyst bed at moderate pressure and in the presence of hydrogen. For cracked naphthas this also involves saturation of olefins.
- "Cryogenic LPG recovery" means a refinery unit in which liquefied petroleum gas (LPG) is extracted from refinery gas streams through cooling and removing the condensate heavy fractions. The processes and equipment for this unit include, but are not limited to, refrigeration, drier, compressor, absorber, stripper and fractionation.
- "Cumene production" means alkylation of benzene with propylene.
- "Cyclohexane production" means hydrogenation of benzene to cyclohexane over a catalyst at high pressure.
- "Delayed Coker" means a refinery unit which conducts a semi-continuous process, ~~similar in line-up to a visbreaker,~~ where the heat of reaction is supplied by a fired heater. Coke is produced in alternate drums that are swapped at regular intervals. Coke is cut out of full coke drums ~~and disposed of~~ as a product. For the purposes of analysis, facilities include coke handling and storage.
- "Desalination" means a refinery's desalination of sea water or contaminated water. It includes all such processes.
- "Desulfurization of C4–C6 Feeds" means desulfurization of light naphthas over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.
- "Desulfurization of pyrolysis gasoline/naphtha" means selective or non-selective desulfurization of pyrolysis gasoline (by-product of light olefins production) and
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other streams over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.

- “Diolefin to olefin saturation of gasoline” means selective saturation of diolefins over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen, to improve stability of thermally cracked and coker gasolines.
- “Distillate hydrotreating” means desulfurization of distillate ~~virgin kerosene~~ over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen.
- “Ethylbenzene production” means the process of combining benzene and ethylene to form ethylbenzene.
- “FCC gasoline hydrotreating with minimum octane loss” means selective desulfurization of FCC gasoline cuts with minimum olefins saturation, over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.
- “Flare gas recovery” means a refinery unit in which flare gas is captured and compressed for other uses. Usually recovered flare gas is treated and routed to the refinery fuel gas system. Depending upon the flare gas composition, recovered gas may have other uses. The equipment for this process includes, but is not limited to, the compressor and separator.
- “Flexicoker” means a refinery unit which conducts a proprietary process incorporating a fluid coker ~~and~~ where ~~the surplus~~ coke is gasified to produce a so-called "low BTU gas" which is used to supply the refinery heaters and surplus coke is drawn off as a product.
- “Flue gas desulfurizing” means a process in which sulfur dioxide is removed from flue gases with contaminants. This often involves an alkaline sorbent which captures sulfur dioxide and transforms it into a solid product. Various methods exist with varying sulfur dioxide removal efficiencies. Flue gas desulfurizing systems can be of the regenerative type or the non-regenerative type. The processes and equipment for this process include, but are not limited to, the contactor, catalyst/reagent regeneration, scrubbing circulation and solids handling.
- “Fluid Catalytic Cracking” means cracking of a hydrocarbon stream typically consisting of ~~vacuum~~ gasoils and residual feedstocks over a catalyst. The finely divided catalyst is circulated in a fluidized state from the reactor where it becomes coated with coke to the regenerator where coke is burned off. The hot regenerated catalyst returning to the reactor supplies the heat for the endothermic cracking reaction and for most of the downstream fractionation of cracked products.
- “Fluid Coker” means a proprietary continuous process where the fluidized powder-like coke is transferred between the cracking reactor and the coke burning vessel and burned for process heat production. Surplus coke is drawn off and ~~disposed of~~ as a product.

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- “Fuel gas sales treating & compression” means treatment and compression of refinery fuel gas for sale to a third party.
- “Hydrogen Generation” means a unit producing hydrogen. Steam Methane Reforming, includes units producing hydrogen from steam reforming of natural gas or refinery gases. Steam Naphtha Reforming includes units producing

hydrogen from steam reforming of naphtha. Partial Oxidation Units produce steam from partial oxidation of fuel oil. The primary product is hydrogen. Low btu gas or Carbon Dioxide are byproducts of these plants. The CWB factors for hydrogen purification units, such as Cryogenic Unit, Membrane Separation Unit, and Pressure Swing Adsorption (PSA) unit, as well as U71 (CO Shift & H2 Purification) and U72 (POX Syngas for H2 Generation), are allocated among Hydrogen Generation units.

- “Hydrodealkylation” means dealkylation of toluene and xylenes into benzene over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure.
- “Kerosene hydrotreater” means a refinery process unit which treats and upgrades kerosene and gasoil streams using “aromatic saturation of distillates,” “distillate hydrotreating,” “middle distillate dewaxing” or the “S-Zorb™ process for kerosene and gasoil” or “selective hydrotreating of distillates.”
- “Lube catalytic dewaxing” means catalytic breakdown of long paraffinic chains in intermediate streams in the manufacture of lube oils.
- “Lube solvent dewaxing” means solvent removal of long paraffinic chains (wax) from intermediate streams in the manufacture of lube oils. Includes solvent regeneration. Different proprietary processes use different solvents, such as chlorocarbon, MEK/toluene, MEK/MIBK, or propane.
- “Lube solvent extraction” means solvent extraction of aromatic compounds from intermediate streams in the manufacture of base lube oils. This includes solvent regeneration. Different proprietary processes use different solvents, such as Furfural, NMP, phenol, or SO2.
- “Lube/Wax hydrofining” means hydrotreating of lube oil fractions and wax for quality improvement.
- “Lubricant hydrocracking” means hydrocracking of heavy feedstocks for the manufacture of lube oils.
- “Methanol synthesis” means recombination of CO2 and hydrogen for methanol synthesis. This factor is only applicable when a refinery produces hydrogen via partial oxidation.
- “Middle distillate dewaxing” means cracking of long paraffinic chains in gasoils to improve cold flow properties over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. This process includes the desulfurization step which should therefore not be accounted for separately.
- “Mild Residual FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of 2.25% to 3.5% by weight.
- “Naphtha/Distillate Hydrocracker” means a refinery process unit which conducts cracking of a hydrocarbon stream typically consisting of distillates and gasoils ~~vacuum gasoils and cracked heavy distillates~~ over a fixed catalyst bed, at high pressure and in the presence of hydrogen. The process combines
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cracking and hydrogenation reactions. ~~Conversion of naphtha into C3-C4 hydrocarbons is included here.~~

- “Naphtha Hydrotreater” means a refinery process unit which treats and upgrades a hydrocarbon stream typically consisting of naphtha/gasoline and lighter streams. It includes the following process units; Benzene Saturation, Desulfurization of C_4 -C_6 Feeds, Conventional Naphtha Hydrotreating, Diolefin to Olefin Saturation of Gasoline, FCC Gasoline Hydrotreating with Minimum Octane Loss, Olefinic Alkylation of Thiophenic Sulfur, Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization, Pyrolysis Gasoline Desulfurization, Reactor for Selective Hydrotreating and S-Zorb™ Process.
- ~~Naphta~~ hydrotreater~~” means a refinery process unit which treats and upgrades~~ a ~~hydrocarbon stream typically consisting of naphtha/gasoline and lighter streams using “benzene saturation,” “desulfurization of C4–C6 feeds,” “conventional naphtha hydrotreating,” “diolefin to olefin saturation of gasoline,” “FCC gasoline hydrotreating with minimum octane loss,” “olefinic alkylation of thio sulfur,” and/or “desulfurization of pyrolysis gasoline/naphtha,” is a “reactor for selective hydrotreating” and may also use the “S-Zorb™ process for naphta/distillates.”~~
- “Olefinic alkylation of thio sulfur” means a gasoline desulfurization process in which thiophenes and mercaptans are catalytically reacted with olefins to produce higher-boiling sulphur compounds removable by distillation. This does not involve hydrogen.
- “Other FCC” means early catalytic cracking processes on fixed catalyst beds, including Houdry catalytic cracking and Thermofor catalytic cracking.
- “Oxygenates” means ethers produced by reacting an alcohol with olefins.
- “Paraxylene production” means physical separation of paraxylene from mixed xylenes.
- “Propane/Propylene splitter (propylene production)” means a refinery unit that conducts separation of propylene from other mostly olefinic C3/C4 molecules generally produced in an FCC or coker. Its product is propylene and must be chemical or polymer grade. "Chemical" and "polymer" are two grades with different purities.
- “POX syngas for fuel” means production of synthesis gas by gasification (partial oxidation) of heavy residues. This includes syngas clean-up.
- “Reactor for selective hydrotreating” means a special configuration where a distillation/fractionation column contains a solid catalyst that converts diolefins in FCC gasoline to olefins or where the catalyst bed is in a preheat train reactor vessel in front of the column.
- “Reformer - including AROMAX” means a refinery unit which increases the octane rating of naphtha by dehydrogenation of naphthenic rings and paraffin isomerisation over a noble metal catalyst at low pressure and high temperature. The process also produces hydrogen. Different configurations of the process are possible.
- “Residual FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of greater than or equal to 3.5% by weight.

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- “Residual hydrotreater” means a refinery unit which conducts desulfurization of residues over a fixed catalyst bed at high pressure and in the presence ofhydrogen. It results in a limited degree of conversion of the residue feed into lighter products.
- “Residual Hydrocracker” means a refinery unit which conducts hydrocracking of residual feedstocks. Different proprietary processes involve continuous or semicontinuous catalyst replenishment. The residual hydrocracker unit must be designed to process feed containing ~~at least 50% mass of~~ vacuum ~~residue~~ residuum ~~(defined as boiling over 550°C)~~ for it to qualify as a residual hydrocracker for the purposes of complexity-weighted barrel throughputs.
- “S-Zorb™ process for kerosene and gasoil” means desulfurization of gasoil using a proprietory absorbtion process. This process does not involve hydrogen.
- “S-Zorb™ process for naphtha/distillates” means desulfurization of naphtha/gasoline streams using a proprietary fluid-bed hydrogenation adsorption process in the presence of hydrogen.
- “Selective hydrotreating of diolefins ~~distillates~~” means selective saturation of diolefins in C4 streams for alkylation over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen,
- “Selective hydrotreating of distillates” means selective hydrotreating to produce a low contaminant distillate.~~or hydrotreatment of distillates for conversion of diolefins to olefins.~~
- “Solvent deasphalter” means a refinery unit which utilizes a solvent, such as propane, butane or a heavier solvent, to remove asphaltines from a residual oil stream and produces asphalt and a deasphalted gas oil. ~~conducts separation of the lighter fraction of a vacuum or cracked residue by means of a solvent such as propane, butane or heavier.~~
- “Special Fractionation” means fractionation processes ~~excluding solvents, propylene and aromatics fractionation,~~ which are accomplished by a deethanizer, depropanizer, deisobutanizer, debutanizer, deisopentanizer, depentanizer, deisohexanizer, dehexanizer, deisoheptanizer, deheptanizer, naphtha splitter, alkylate splitter or reformate splitter. Production of solvents, propylene and aromatics are excluded from “Special Fractionation” but included elsewhere.
- “Standard FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of less than 2.25% by weight.
- “~~Sulfur~~ Sulfur Recovery ~~(recovered~~)” means a process where hydrogen sulfide is ~~removed from the process and~~ converted to elemental sulfur. Typical units used in this process include: Sulfur Recovery Unit, Tail Gas Recovery Unit, and H2S Springer Unit. ~~sulfur produced by partial oxidation of hydrogen sulfide into elemental sulfur.~~
- “Sulfuric acid regeneration” means a catalytic process in which spent acid is regenerated to concentrated sulfuric acid. The equipment for this process includes, but is not limited to, the combustor, waste heat boiler, converter, absorber, SO_3 recycle, gas cleaning including electrostatic precipitator and amine regenerator.

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- "Thermal Cracking" means thermal cracking of distillate feedstocks. A thermal cracking unit may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.
- "Toluene disproportionation/transalkylation means a fixed-bed catalytic process for the conversion of toluene to benzene and xylene in the presence of hydrogen.
- "Vacuum Distillation" means distillation of atmospheric residues under vacuum. ~~The process line up must include a heater.~~ Some units may have more than one main distillation column.
- "Visbreaker" means a refinery unit which conducts mild thermal cracking of residual feedstocks to produce some distillates and reduce the viscosity of the cracked residue. It may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.
- "VGO Hydrotreater" means a refinery unit which conducts desulfurization of a hydrocarbon stream typically consisting of vacuum and cracked gasoils usually destined to be used as FCC feed, over a fixed catalyst bed at medium or high pressure and in the presence of hydrogen.
- "Wax deoiling" means solvent removal of lighter hydrocarbons from wax obtained from lube dewaxing. Different proprietary processes use different solvents, such as MEK/toluene, MEK/MIBK, or propane.
- "Xylene isomerization" means isomerization of mixed xylenes to paraxylene. [WSPA 2]

Comment: The total facility CWB production must be calculated according to the following formula.

$CWB = \sum CWB_{Factor} * Throughput + CWB_{Off\text{-}Sites\ and\ Non\text{-}Energy\ Utilities} + CWB_{Non\text{-}Crude\ Sensible\ Heat}$

Where:
"CWB" = The total amount of complexity weighted barrels from a petroleum refinery.
"CWBFactor" = The CWB factor for each process found in Table 1 of this section.
"Throughput"= The reported value for each CWB function identified in Table 1 of this section reported pursuant to section 95113(I)(43)(A).

"$CWB_{Off\text{-}Sites\ and\ Non\text{-}Energy\ Utilities}$" = 0.327 * Total Input + .0085 * $\sum CWB_{Factor}$ * Throughput

"$CWB_{Non\text{-}Crude\ Sensible\ Heat}$" = 0.44 * Non-Crude Input Barrels (WSPA 2)

Response: These comments are outside of the scope of the proposed modifications so no response is required. These comments were addressed by ARB staff in 45-day comments A-25, D-1, and D-2 and 15-day comment M-6 in the Final Statement of Reasons for MRR filed on November 18, 2013.

B-9. True-Up Allocations

Support for General True-Up Provisions

B-9.1. Multiple Comments: Kern supports the proposal to allow limited borrowing of true-up allowances. As proposed, this "borrowing" would allow facilities to use up to the amount of true-up allowances provided for compliance obligation up to two years prior to the vintage of the allowances provided by the true-up. For example, the if true-up allowances are granted for the 2015 true-up process, these would be 2015 vintage , but they can be used to satisfy the 2013 obligation since that is what was being "trued-up." Staff's proposed definition of "trueup" at Section 95891(b) is helpful in clarifying this ability to borrow true-up allowances within the hierarchal order of surrendering compliance instruments as described in Section 95856(h). (KERN)

Comment: Phillips 66 supports the amendments related to allowance True-Up provisions. (PHILLIPS 1)

Comment: Air Products Supports Permitting a Covered Entity to Satisfy its Compliance Obligation with Allowances Allocated Just Before the Surrender Deadlines, Up to the True-up Allowance Amount – Air Products supports the proposal to allow limited "borrowing" by allowing facilities to use up to the amount of true-up allowances provided for meeting the compliance obligation two-years prior to the vintage of allowances provided by the true-up. Combined with the earlier distribution date of the allowance allocation, these provisions will allow covered entities to optimally manage their compliance instrument procurement strategies. (APC 1)

Comment: Inergy supports replacing the November 1 date by which allowances will be annually allocated to eligible covered entities with the October 15 date (see revised Section 95870(e)(l) in the Cap-and-Trade Regulation), and recommends that CARB adopt the change. This change helps resolve the allowance timing issue Inergy described in its August 2, 2013 comments on the proposed revisions to the Cap-and-Trade Regulation. (INERGY)

Comment: CLFP supports the True-Up provisions contained in new section 95891(b) which allows the use of "future" allowances provided for allocation true-up to meet past compliance obligations under specified circumstances. (CLFP 1)

> **Response:** Thank you for the support.

Requests for Clarification

B-9.2. Comment: In the draft regulations section 95856(h)(1)(d) and (h)(2)(d), it appears to state that t-2 ("true-up") allowances [allocated to account for changes in production and not properly accounted] are allowed to be used for (the current year's) compliance obligation.

In the draft regulations, it is not clear whether “true-up” allowances provided in future years (post-2015) will also be usable in the same way for the current year’s compliance obligation.

Could you please clarify whether the same will be true for t-2 allowances in future years? For example, are true-up allowances that are allocated in the form of vintage 2018s for a calendar year 2016 increase in production valid to be used for an entity’s 2016 compliance obligation? (ELEMENT)

> **Response:** Section 95856(h)(1) and (h)(2) describe the retirement order of compliance instruments. Please refer to section 95891(b) of the Cap-and-Trade Regulation for more information on true-up allowances. In 95891(b), the true-up “is the amount of true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations. This value of allowances for budget year ‘t’ shall be allowed to be used for budget year ‘t-2’ pursuant to 95856(h)(1)(D) and 95856(h)(2)(D).” Thus, the amount of true-up allowances can be used to satisfy a compliance obligation two years prior to the vintage of the allowance allocation. Using the example stated, vintage 2018 true-up allowances distributed in 2017 could be used for a 2016 emissions year compliance obligation.

Decreases in Production

B-9.3. Comment: However, we are concerned from something we first saw this morning that the staff is proposing to make unidentified changes to the current true up language where there has been a decrease in production. We believe any new any changes in the true up provisions must be coupled with recognition that facilities may have emissions without having proportional CWB.

We're in the process of reconfiguring our California refineries. These unspecified rule changes can have significant impact on us and similarly situated entities. These clarifications have never been mentioned or discussed in any of the staff's previous notices on this rule making package before today. We believe fundamental fairness requires businesses be given a full comment period to review and comment on any staff proposals.

Moreover, we believe that under the Administrative Procedures Act, any such changes must go through a full comment period since they were never mentioned or discussed in any of the staff's previous notices on this rule package. (PARAMOUNT 1)

> **Response:** The true-up allowances account for changes in production or allocation not properly accounted for in prior allocations. The true-up allowances maintain the correct incentives by linking a facility’s covered emissions to the actual production that year. The true-up allowances are calculated consistent with the CWB approach.

Changes made to the true-up provisions were present in the proposed regulatory amendments posted September 4, 2013.

B-9.4. Comment: However, the ARB proposed amendments contain provisions that may injure smaller obligated entities, those emitting <100 MMTCO2e annually, based on a emissions decline during the first compliance period when subject to the energy-based benchmark.

Food processors are subject to the vagaries and unpredictability of weather, varying crop yields, and disease. The raw product must be processed within a few short hours of harvest and cannot be stored or stockpiled to hedge against the risks posed by Mother Nature. Adding the burden of the potential loss of industry assistance only adds to the burden of uncertainty that food processors face.

CLFP opposes any determination that would decrease industry assistance under the proposed true-up methodology where any decrease in emissions in the first compliance period arise from circumstances unrelated to market demand or technology for obligated entities with annual emissions <100 MMTCO2e. (CLFP 1)

Response: The true-up allowances account for changes in production or allocation not properly accounted for in prior allocations. The true-up allowances maintain the correct incentives by linking a facility's covered emissions to the actual production that year. If a facility produces more than earlier, it will receive additional allowances; if less, it will receive less allowances.

The program is designed to deal with fluctuations in emissions and production by using three-year compliance periods. These compliance periods mean that an entity surrenders most of their allowances at the end of the compliance period. This smooths out spikes in emissions due to any annual variation as they are expected to average out during the compliance period.

B-10. Universities and Public Service Facilities

B-10.1. Multiple Comments: SCE also supports the ARB's new allocation of allowances to University Covered Entities, which will help these facilities transition to the new GHG-inclusive marketplace. (SCE 1)

Comment: SMUD supports the modification proposed in the Proposed Regulation Order to provide allowances to public and private university covered parties. SMUD believes that the provision will reduce the incentives of such entities to forego their combined heat and power systems in order to reduce their compliance obligations or even avoid being a covered entity altogether. (SMUD 2)

Comment: Maureen Gorsen with Alston & Bird. We're representing Loma Linda Hospital and Medical Center. Loma Linda is an educational health sciences institution in Riverside County offering degrees to over 4,000 students in medicine, dentistry, nursing, pharmacy, and public health. They also operate a medical center, a nonprofit medical center, and a 900 bed hospital. This is where I'll just blow kisses to staff.
Loma Linda would not be subject to cap and trade but for the fact that it installed a combined heat and power system to more efficiently meet its energy needs. We support the amendments to provide transition assistance to Loma Linda University and support the 100 percent transition assistance through the second compliance period.
At one point, Loma Linda had estimated its cost to purchase allowance to be in excess of $750,000 a year. That would be an incredible hardship. Loma Linda admits more than 33,000 inpatients and serves over 500,000 out-patients, and over 70 percent of its patients are on Medicare or Medicaid. They cannot pass on those costs. We urge CARB to adopt the amendments. (LLH)

> **Response:** Thank you for the support. ARB staff notes that transition assistance to university covered entities and to EITEs is reduced each year by the cap decline factor shown in Table 9-2 of the Regulation, and therefore is not equivalent to 100 percent transition assistance.

B-10.2. Comment: LA County greatly appreciates ARB staffs efforts to provide transition relief to the County and similarly situated municipal entities in order to ensure that the County can continue to invest in energy efficiency and other greenhouse gas ("GHG") reduction measures.

The County strongly supports allocating allowances to University Covered Entities and Public Service Facilities. While the County supports the general approach contemplated by the Proposed Amendments, however, it respectfully requests clarification and modification of certain provisions pertinent to Public Service Facilities in order to ensure that the effect of the regulation is consistent with ARB's intent.

Specifically, the County requests: (1) modification of the definition of Public Service Facility so as not to exclude facilities that sell a portion of chilled water and steam production to third parties; and, (2) modification of the allocation formula in order to clarify that the allowance allocation for Public Service Facilities will include power provided to public entities at offsite facilities separate from the generation facility. LA County faces significant GHG compliance costs resulting from emissions produced by two 25 MW cogeneration facilities owned and operated by the County. Each facility is responsible for approximately 100,000 tons of CO_2 production annually.

The Pitchess Detention Center cogenerator ("Pitchess Cogen") provides steam and electricity for the Pitchess Detention Center which is owned .and operated by the County. The County sells, on average, 20 MW of the Pitchess Cogen's electrical output to Southern California Edison ("SCE") pursuant to a 1985 power purchase agreement. The Civic Center cogenerator ("Civic Center Cogen") provides steam, chilled water and electricity to facilities throughout the County, nearly all of which are owned and/or operated by the County, such as the Hall of Administration and the Disney Center, and two of which are not, the Catholic Archdiocese and the Los Angeles Law Library. The County wheels approximately 21 MW of Civic Center Cogen's electrical output over Los Angeles Department of Power and Water ("LADWP") transmission facilities for use at other County facilities and utilizes 3 MW onsite for chillers and ancillary equipment. [Footnote: In previous informal comments to ARB staff the County incorrectly stated that power produced by Civic Center Cogen was being sold to LADWP. In fact, however, LA County wheels the power over LADWP transmission facilities for use at other County owned facilities. This arrangement is subject to a contract between LADWP and LA County.]

Between 2002 and 2006, the County invested over $3 million in efficiency upgrades to the Civic Center Cogen. As a result, the Civic Center Cogen has a significantly lower GHG emissions factor than LADWP grid power. If the County is forced to shut down the Civic Center Cogen due to high operating costs, it will serve the load currently served by Civic Center with purchased power supplied by LADWP, resulting in a net increase in GHG emissions.

In addition to the GHG compliance costs for the County's cogeneration facilities, LA County faces significant embedded GHG costs in utility electric rates. LA County is SCE's largest customer and one of LADWP's largest customers. Pursuant to California Public Utilities Commission Decision ("D.")12-12-033, SCE will provide rebates to certain classes of ratepayers to offset embedded GHG compliance costs. Rebates will be provided to emissions intensive and trade exposed industrial, small business, and residential ratepayers. No rebate will be provided to local governments. The County will receive a de minimus GHG revenue rebate for power purchased from SCE under the small business rate schedule, which is approximately 3% of the County's total load. The vast majority of the County's load is on SCE rate schedules for large customers, which were excluded from relief per D.12-12-033 and Senate Bill 1018.

The County has demonstrated leadership on energy efficiency and sustainability through a number of initiatives, many of which are ongoing. Based on current and planned actions alone, the County will reduce GHG emissions by 15% below 2009 levels by 2020, consistent with the target' set by the ARB Scoping Plan. The County's Climate Action Plan, however, shows that the County is likely to exceed the AB 32

target. In addition to achieving GHG reductions in County facilities, the County has developed and supports a number of county-wide and regional programs to facilitate GHG reductions in buildings owned by private businesses and individuals as well as other public agencies. The County anticipates reinvesting any cost savings resulting from allocation of allowances in future additional GHG reduction measures.
LA County proposes the following modifications to the Proposed Amendments prior to adoption by the Board:

The definition of Public Service Facility in the Proposed Amendment would limit relief to facilities that "provide steam and chilled water solely to buildings owned by the local government, and may also provide electricity to its own facilities or for sale to an electrical distribution utility." The County proposes modifying this provision to be consistent with the definition of University Covered Entity so as not to exclude from relief facilities which sell chilled water and steam.

As described above, the County provides chilled water and steam, but not electricity, to multiple County owned and/or operated facilities, and to two non-County entities, the LA Catholic Archdiocese Cathedral and the Los Angeles Law Library. Under the current Proposed Amendment, the Civic Center Cogen would not be eligible for an allocation of allowances as a Public Service Facility. No similar restriction on sales of steam and chilled water for offsite use applies to University Covered Entities.

It is unclear what purpose would be served by excluding facilities which provide steam and chilled water to third party-owned facilities. To the degree that ARB wishes to avoid allocating allowances to Public Service Facilities for emissions resulting from the sale of chilled water and steam provided to third parties, it should be addressed through the allocation formula, as described below.

> **Recommendation:** As such, the County requests that the definition of Public Service Facility be modified as follows:
>
> "Public Service Facility" means a facility that is a covered entity or opt-in covered entity owned by a local government as defined in Government Code section 53720(a), excluding facilities owned or operated by an electrical distribution utility, ~~that provides steam and chilled water solely to buildings and facilities owned by the local government, and may also~~ which may provide electricity to its own facilities or for sale to an electrical distribution utility.
> The Proposed Amendment provides for the direct allocation of allowances to Public Service Facilities. The amount of allowances to be allocated is determined by the allocation formula described in section 95891(e). The allocation formula, simplified for the purposes of these comments, would result in an allocation of allowances based on average historical fuel consumption minus power sold or provided for offsite use. While LA County is strongly supportive of allocating allowances for operation of Public Service Facilities, it suggests the following limited modifications to this provision.

Power produced by a Public Service Facility which is used by the local government at offsite facilities should not be included in e_{sold}. The definition of e_{sold} in section 9589l(e)(l) of the Proposed Amendment, would exclude from the allocation formula any power generated by the Civic Center Cogen, wheeled over LADWP transmission facilities, and used by the County at "offsite" facilities . Specifically, the phrase "or provided for off-site use" could be read to exclude from the allocation formula all power wheeled to the Hall of Administration and other County facilities not directly adjacent to the Civic Center Cogen. Given that the significant majority of power output from the Civic Center Cogen is wheeled over LADWP facilities for offsite use at other County-owned facilities, this restriction would completely eliminate any transition assistance for power output from the Civic Center Cogen.

It is the County's understanding that the purpose of excluding e_{sold} from the allocation formula is to ensure that transition assistance is not provided for GHG compliance costs which may be passed on to an end-user, such as a power purchaser. This purpose is not served by restricting the County's ability to wheel power to itself. As such, the definition of e_{sold} in section 95891(e)(l) should be modified as follows:

"e_{sold}" is the historical baseline arithmetic mean amount of electricity sold <u>to an entity other than the university or local government which owns the Public Service Facility </u>or provided for off-site use, measured in MWhs.
If the definition of Public Service Facility is modified as described above, the allocation formula should be modified to subtract allowances for sales of chilled water and steam.

Pursuant to the allocation formula in the Proposed Amendment, simplified for the purposes of these comments, eligible entities would be allocated allowances based on average historical fuel consumption minus power sold or provided for offsite use. If the definition of Public Service Facility is modified to include facilities that sell chilled power and water to unaffiliated entities, as proposed above, the allocation formula should be modified to subtract emissions associated with the production of chilled water and steam.

The County strongly supports the allocation of allowances for Public Service Facilities. ARB should move to adopt the Proposed Amendment with the limited clarifications and modifications described above. (LACOUNTY)

Response: ARB staff appreciates the commenter's support for the general approach. The intent is to provide allowances to local government public service facilities in consideration of emissions associated with electricity or thermal output used by the local government. ARB staff does not provide allocations for electricity or steam that is sold, because staff expects local governments to pass though the GHG costs when such sales are made. Although ARB staff has not made the exact modifications requested, ARB staff has modified the definition of "public service facility" and the equations for allocation and definitions of the equations' terms to more clearly carry out this intent.

B-10.3. Comment. D. The definition of "Public Service Facility" should be revised for clarity.

Proposed new section 95802(a)(284) defines "Public Service Facility" as:

a facility that is a covered entity or opt-in covered entity (i) owned by a local government as defined in Government Code section 53720(a) or (ii) supplying steam under an existing agreement to a facility meeting the definition of an educational facility pursuant to Education Code section 94110(e) excluding facilities owned or operated by an electrical distribution utility, that provides steam and chilled water solely to buildings and facilities owned by the local government or to a publicly-owed [*sic*] education facility, and may also provide electricity to its own facilities or for sale to an electrical distribution utility.

Under proposed new section 95870(f), Public Service Facilities are to receive an allocation of allowances from the ARB. However, a facility (physical plant) cannot itself be a covered entity and receive allowances; the entity that operates the facility is the one that must register and open an account for the allowances. The Regulation should keep the distinction between entities and facilities clear: an entity (a person, company or other organization) can take actions and will be liable for its actions; a facility cannot.

Therefore, the term "Public Service Facility" should be changed to "Public Service *Entity*" in the definitions and throughout the Regulation.

Recommendation: SCPPA's proposed changes to section 95802(a)(284) are set out below:

(284) "Public Service ~~Facility~~Entity" means ~~a facility that is~~ a covered entity or opt-in covered entity ~~(i) owned by a local government as defined in Government Code section 53720(a) or (ii) supplying steam under an existing agreement to a facility meeting the definition of an educational facility pursuant to Education Code section 94110(e) excluding facilities owned or operated by~~ (other than an electrical distribution utility), that operates a facility that provides steam and chilled water solely to buildings and facilities owned by a~~the~~ local government as defined in Government Code section 53720(a) or to a publicly-owned education facility pursuant to Education Code section 94110(e), and may also provide electricity to its own facilities or for sale to an electrical distribution utility. (SCPPA 1)

Response: Because the definition of "public service facility" includes a requirement that the public service facility is a covered entity or opt-in covered entity, ARB staff does not deem it necessary to make the proposed changes.

B-10.4. Comment: General Provisions for Direct Allocations (95890(d)), (page 132)) ARB is proposing to provide free allowances to non-EITE entities (Universities, Public Service Facilities, etc.) i.e.: State Government facilities. While ARB has stated its reasoning behind the gift of allocations to these entities, nevertheless the allowance allocation amounts to a waiving of the rules, appearing more a special treatment based on political sensitivity rather than program dynamics. As all private industrial emitters have been subjected to a rigorous effort to enforce compliance, CLFP believes that ARB's actions raise questions as to the goals of the program given state facilities are receiving different treatment than private companies under the rules. As such, CLFP opposes this proposal. (CFLP 1)

> **Response:** As stated in the comment, the rationale for providing allowances to Universities and Public Service Facilities is distinct from that used in awarding allowances to emissions-intensive, trade-exposed industries. These allocations provide recognition for leadership in reducing GHG emissions, as well as transition assistance to sectors that benefit all Californians. Allocation to these entities benefits taxpayers of California that fund local governments and provide a substantial portion of university funding. In part, this is similar to allocation to EDUs for ratepayer benefit, because ratepayers and taxpayers include virtually all people living in the State.

B-10.5. Comment: To date, ARB has not addressed CCDC's proposal that eligibility for the transitional assistance for Universities and public service facilities that have taken early actions be expanded to include other institutional and private entities, whether serving public or private buildings, who have demonstrated similar early action and leadership behavior. CCDC has attached its prior comments regarding transitional assistance to this letter, and requests that ARB consider and address them in any revisions to the Cap-and-Trade Regulation.

Among other things, Resolution 12-33 called for an allocation of allowances to universities. The discussion draft revisions to the Cap-and-Trade Regulation include the transition relief for Universities. As proposed by staff, that relief has appropriately been expanded to also include public service facilities.

ARB proposes transitional assistance for Universities that have taken early actions and provided leadership to reduce GHG emissions though investments in efficiency and renewable energy. For Universities that are subject to the Cap and Trade Program, most or all of which have an operational CHP system, allowances equal to their three year historical fuel use baseline (excluding electricity exports) would be provided for 2013 and decline in proportion to the cap through 2020. CCDC supports this action and recommends that eligibility be broadened to include other institutional and private entities who have demonstrated similar early action and leadership behavior.

Allowances for Universities and Public Service Facilities

Staff proposes transitional assistance for Universities and public service facilities subject to the Cap-and-Trade Program, many of which have operational systems, through allowances equal to their three-year historical fuel use baseline {excluding electricity exports), beginning in 2013 and declining in proportion to the cap through 2020. CCDC supports this action, including the expansion to include public service facilities. CCDC continues to recommend that eligibility for this transitional assistance be broadened to include other institutional and private entities, whether serving public or private buildings, who have demonstrated similar early action and leadership behavior. (CCDGCD)

> **Response:** There are two primary reasons for providing allowances to universities and public service facilities. The first is to provide transition assistance to these specific groups for the benefit of all Californians. The second reason is to recognize university and municipal leadership in reducing GHG emissions through their programs, including conducting research and development in emissions-reducing technologies. Allocation to these entities benefits California taxpayers, who fund local governments and provide a substantial portion of university funding. In part, this is similar to allocation to EDUs for ratepayer benefit, because ratepayers and taxpayers include virtually all people living in the State. The rationale for providing allowances to universities and public service facilities does not extend to other sectors.

C. LEAKAGE

C-1. Changes to the Industrial Assistance Factor

Support for Changes to the Industrial Assistance Factor

C-1.1. Multiple Comments: (Summary) Air Products supports the proposal to shift the Industry Assistance Factors by one compliance period, providing additional time and certainty to industry to make necessary investments in efficiency improvements and emission reduction technologies. (APC 1)

Comment: … we really do want to thank the staff for recommending that the industry assistance factor be increased in the second compliance period. And that we should all recognize with the efficiency benchmarks, we're still seeing and we will be seeing reductions in the manufacturing sector in a cost effective and technologically feasible way with 100 percent allowance allocation up to these efficiency benchmarks. (CMTA 1)

Comment: Lastly, I want to express our support for the amendments that will increase the assistance factor in the second and third compliance period and also the allowance for limited borrowing of true up allowances. (KERN 3)

Comment: (Summary) We look forward to working with the staff on the leakage exposure assessments. For today, we urge the Board to adopt the proposed amendments to the assistance factors for the first three compliance periods. (SOLAR)

Comment: WSPA strongly supports the ARB's proposed increases in Industry Assistance Factors for the 2nd and 3rd compliance period. WSPA pledges to work with ARB to determine whether the remaining reduction of 25% that exists in the 3rd compliance period is truly needed or whether it may contribute to leakage and trade exposure. (WSPA 1)

Comment: (Summary) Chevron strongly supports ARB's proposed amendment to extend the first and second compliance period industry assistance factor into the second and third compliance periods as it will create a more measured start to the program. Chevron welcomes the opportunity to work with ARB in future leakage analysis efforts regarding the refining industry. (CHEVRON 1)

Comment: (Summary) Western Growers Association appreciates the proposal ARB has made to maintain the current Industry Assistance Factor (IAF) of 100% for the 2nd compliance period and the subsequent raise from 50-75% in the third compliance period for the medium risk category. (WGA)

Comment: The Coalition supports CARB Staff's proposal to extend the assistance factor levels from the first compliance period into the second and third compliance periods. Specifically, Staff proposes to amend Table 8-1, section 95870, to increase the assistance factor to 100% in the second compliance period and to 75% in the third compliance period. The assistance factor adjustment will provide the industry additional certainty and time and, ultimately, will help minimize leakage risk. (CFEA 3)

Comment: ARB proposes to increase the assistance factor to 100% in the second compliance period and to 75% in the third compliance period by amending Table 8-1, section 95870. Kern appreciates the additional cushion that the increase will provide in terms of time and certainty and also believes the increase will help minimize leakage risk. (KERN 2)

Comment: CLFP strongly supports the ARB's proposed increases in Industry Assistance Factors for the 2nd and 3rd compliance periods. CLFP will continue to work with ARB to determine whether the remaining reduction of 25% that exists in the 3rd compliance period is truly needed to meet emissions targets or whether it may contribute to leakage and trade exposure. (CLFP 1)

Comment: Phillips 66 supports extending the First Compliance Period's industrial assistance factor through the Second Compliance Period. (PHILLIPS 1)

Comment: Alon supports the staff recommendation to extend the First Compliance Period's industrial assistance factor through the Second Compliance Period while additional leakage analysis is completed. Leakage protection is an important and fundamental component of the Cap-and-Trade program as required by AB 32.

Therefore, when research is still ongoing, it is entirely appropriate for the Board to take the conservative regulatory approach shown with this recommendation. (PARAMOUNT 1)

Comment: We really do want to thank the staff for recommending that the industry assistance factor be increased in the second compliance period. (CMTA 1)

Comment: We support the ARB's proposal to increase the industry assistance factor for the second or third compliance period. We are encouraged that the Board will continue to study the issue of trade exposure and leakage and look forward to the results when they come up with respect to a third compliance period. (WSPA 3)

Comment: Regarding the industry assistance factor, Ag Council is working with the Air Resources Board and its private contractors to work on a leakage analysis for the food processing industry. And we're also working on the product-based emissions benchmark. So this process has taken a little bit longer than anticipated. But we are slowly working through that process so we appreciate the extension of free allowances through the second compliance period. (ACC)

Comment: Chevron is very pleased that ARB is considering adoption of several new policies that represent significant improvements in the Cap and Trade Program, the first of which is industry assistance. This industry assistance factor recognizes the competitive environment that refining and other energy intensive and trade-exposed industries faced. And if left unchanged, that competitive disadvantage could lead to leakage and significant impacts on California's economy. We believe this change is really a wonderful and important change to make. We also look forward to working with the Air Resources Board on the studies that are being done to evaluate trade exposure next year. (CHEVRON 3)

Response: Thank you for the support.

C-1.2. Comment: (Summary) The AB 32 Implementation Group (AB 32 IG) continues to support the California Air Resources Board (ARB) proposal to shift the “industry assistance factor” change by one compliance period of the cap-and-trade program. This proposal will reduce some of the compliance costs with AB 32 which is critical as California’s competitors have no such obligation.

We urge ARB to make the assistance factor for the first compliance period the default assistance factor for the entire cap-and-trade program. Any withholding of allowances creates costs on California businesses that competitors are not subject to and will result in emissions and economic leakage out of state undermining both the economy of California and the environmental goals of the program.

Using stringent benchmarks for distributing allowances is already placing significant cost pressures on all obligated entities, requiring most companies to buy additional allowances to cover emissions for their normal operations, even in the first compliance period. (AB32IG)

Response: Thank you for the comment. The purpose of the allocation of allowances in the early years of the Cap-and-Trade Program is to provide transition assistance and to minimize leakage. As entities adapt to a GHG emissions cost, transition assistance will decrease and more allowances will be dispensed through auction. As noted by the Economic and Allocation Advisory Committee, the auctioning of allowances is the most economically efficient way to allow price discovery in the Program. For these reasons, ARB staff does not believe that it is appropriate to keep the assistance factor at 100% in perpetuity.

C-1.3. Comment: ARB correctly acknowledges the special challenges posed by a state-level cap-and-trade program. Lacking national greenhouse gas policies, California businesses will be trade exposed as they attempt to internalize the cost of carbon, which in turn is directly set by regulations and policies adopted under AB 32.[58] The proposed extension the industry assistance factor (IAF) for an additional compliance period plus further research on trade exposure will do much to help ease the state’s transition to a low carbon economy. Specifically, the proposed changes to the IAF and the broader coverage for new or opt-in entities provide additional time to study the leakage potential of California businesses and other possible negative

[58] For example, the 10 percent allowance withholding under cap-and-trade works to increase the price of carbon by limiting the number of allowances available to the market.

economic impacts. This additional time is particularly important since the method of analysis for trade exposure is yet untested and may need to be corrected for errors.

CCEEB recommends ARB take a conservative approach by assuming that an entity is trade exposed. Furthermore, evaluation must be done before the start of the second compliance period in order to prevent changes in the IAF resulting in unintended and harmful economic impacts. CCEEB appreciates the currently proposed changes to the industry assistance factor (IAF) and the broader coverage for new or opt-in entities.

CCEEB recommends that ARB continue dialogue with stakeholders on implementation issues, such as: How likely is it that reductions in allowance allocations could lead allowances to leakage of jobs and emissions to facilities outside the state? What documentation is needed in order to evaluate the affect of allowance allocation on cap-and-trade compliance entities as well as the state economy as a whole? What options exist to reduce the impacts on energy-intensive and trade-exposed entities? (CCEEB 1)

> **Response:** ARB's methodology for analyzing trade exposure is laid out in Appendix K to the 2010 Cap-and-Trade Regulation. ARB adopted the trade-exposure metric laid out in The American Clean Energy and Security Act of 2009, and classified the results of the metric into four different levels of trade exposure. ARB is investigating improvements to the metric to better incorporate interstate trade exposure.
>
> The questions about the likelihood of leakage are not within the scope of proposed changes, and therefore require no response. However, ARB staff has ongoing work on leakage classification and monitoring, and is looking into the issues raised in the last paragraph of this comment This ongoing work includes research contracts to develop analytical tools and assess newly available data to monitor for leakage and further assess leakage risks. The research is not expected to conclude until at least after the first year of allocation has occurred for the second compliance period. When research results are available, ARB staff will engage with stakeholders to communicate the results and offer proposals to integrate the results into the Regulation, as necessary.
>
> The options to reduce impacts on energy-intensive, trade-exposed (EITE) entities were investigated and laid out by ARB's Economic and Allocation Advisory Committee in their March 2010 report *Allocating Emissions Allowances Under a California Cap and Trade Program* and include border adjustments and allocating allowances to industry. ARB is currently allocating allowances to EITE entities and investigating the feasibility of border adjustments.

Opposition to Changes to the Industrial Assistance Factor

C-1.4. Multiple Comments: We recommend rejecting the extension of transition assistance to the refinery sector because shifting industrial assistance factors to protect petroleum refineries in California from economic and emissions leakage is unnecessary, and may lead to unfair profits at the expense of California consumers.

While we understand that some California businesses face the real challenge of complying with California's climate change regulations while competing with out-of-state businesses that do not have similar requirements, this is not the case for *all* industries. Accordingly, while EDF takes no issue with the extension of transition assistance for most industries pending the completion of analysis on whether such relief is appropriate, we oppose CARB's proposed regulatory change to maintain 100% assistance for the petroleum refinery sector.

At the outset of the cap-and-trade program design discussions, EDF supported transition assistance for the first compliance period. This balanced approach recognized that California, as a first mover state for comprehensive carbon reductions, must also make sure that in-state businesses are able to compete in the increasingly globalized market for products and services. At that time, the declining assistance factor in the second and third compliance period made sure businesses saw the transition assistance as a short term item – yielding an increasing incentive to modernize operations and increase efficiency.

By the time the second compliance period starts in 2015, AB 32 will have been in existence for eight years, and cap-and-trade in operation for three. As such, large businesses with sufficient capabilities will have had ample time to prepare for the compliance obligations in cap-and-trade, and additional transition assistance is not warranted. Such is the case with the petroleum refining sector.

Accordingly, EDF recommends keeping the current regulatory design until leakage research analysis commissioned by CARB is concluded. Without justifiable results, shifting of assistance factors is premature.

In addition to not being needed, continued distribution of free allowances has the potential to create windfall profits for the state's largest polluters at the expense of California consumers.

The below arguments further explain why continued distribution of free allowances in this second compliance period and potentially the third is not necessary for transition risk or emissions leakage risk for the petroleum refinery sector.

First, petroleum refineries are at little risk of leakage because the costs of transportation and adapting to California fuel standards make it very difficult for out-of-state producers to compete with in-state refineries.[59] A report from the LA Harbor Department and U.S. Army Corps of Engineers supports this point.

[59] Economic Allowance Allocation Committee. 2010. Allocating emissions allowances under a California cap- and-trade program. Recommendations to the California Air Resources Board and California Environmental Protection Agency. March, p. 46.

"Refineries are primarily located in the Bay Area, the Bakersfield area of Central California, and the Lost Angeles Basin in Southern California. Crude pipelines only serve intrastate flows and ***no crude pipelines bring crude or products from out of state.****…* ***only a limited number of refineries in the world (mostly in California) are currently capable of producing products specific to California.****"*[60]

California refineries have already invested the capital necessary to serve the needs of the California market, totaling close to $5.8 billion for facility upgrades.[61] As the eighth-largest economy in the world and the most populous state in the country, California represents a large demand for refinery products. Since California refineries are among the few that can supply this market, there is little risk that they would decrease their operations and that the state would begin to import products at the expense of in-state facility closures.

Second, several pieces of evidence exist to support the idea that the dominant position of California refineries means that they are likely to be able to pass on a substantial portion of any cost increases incurred by the cap and trade regulation – even if those costs are small – because of existing cost containment mechanisms included in the regulation.

For example, a well circulated 2009 analysis prepared for ConocoPhillips by the consulting firm NERA Economic Consulting uses a demand elasticity of -0.5 to support a finding that the cost pass-through rate is 50% for refined petroleum products.[62]

Another report by analysts at the Federal Reserve Bank of Cleveland estimated that 96% of the variation in oil prices is passed on to consumers in gas prices at the pump.[63]

Further, comments in this rulemaking record submitted by Dr. Charles Mason argue that:

"policy adjustment under consideration is unlikely to be effective at preventing California refiners from shutting down any refinery – and therefore not an appropriate or effective mechanism for transition assistance."[64]

[60] From the Pacific L.A. Marine Terminal LLC Crude Oil Terminal Draft SEIS/SEIR (published by the Environmental Management Division of the LA Harbor Department and the U.S. Army Corp of Engineers in 2008).
[61] "California's Oil Refineries." http://energyalmanac.ca.gov/petroleum/refineries.html, October 8, 2013.
[62] NERA Economic Consulting, "Market Conditions and the Pass-through of Compliance Costs in a Carbon Emission Cap-and Trade program," 2009.
[63] Andrea Pescatori and Beth Mowry, "The Pass-Through of Oil Prices to Gasoline Prices," Economic Trends, Federal Reserve Bank of Cleveland, February 2008.
[64] Letter to Steve Cliff from Dr. Charles Mason, August 2, 2013, Proposed Amendments to the AB 32 Cap-and-Trade Program: The Relative Size of Increased Allowance Gifts to Refineries and the Effect on Emissions and Economic Leakage, Available at: http://www.arb.ca.gov/lists/com-attach/57-cap-trade-draft-ws- B2pTNFEjUGxVPVcI.pdf

We estimate the total giveaway value through 2020 to be between $550 million and $750 million depending on future price per allowance[65]. This allowance value represents money that otherwise would be used to fund GHG reductions throughout California, with a specified amount going to investments in the state's most disadvantaged communities. Accordingly, although staff proposed extending transition assistance, "in order to ensure consumers are not negatively impacted by the Program;"[66] the current proposed modification will likely have the opposite effect of reducing the benefits to Californians. Rather than helping consumers, this proposed giveaway will provide additional money to refiners with no restrictions on use or obligations to cut pollution on site.

Third, even if refiners were unable to pass along the entire cost to the consumers, our calculations estimate the giveaway is small compared to the operating profits from these refineries. Accordingly, as currently designed (with declining transition assistance in 2015), the program will have little, if any, effect on refinery competitiveness or decision making for leakage considerations. As stated previously, we estimate the total give away value through 2020 to be between $550 million and $750 million depending on future price per allowance. To put this amount in perspective, per barrel of gasoline, the allowance value is likely between 1% and 2% of the operating profits for these refineries.[67] This is a small fraction of a multi-billion dollar industry and is unlikely to make them exit the state.

Fourth, as admitted in a written memo produced by the Analysis Group and commissioned by the Western States Petroleum Association (WSPA), even refining sector experts agree that free allocation of cap-and-trade credits is not necessary for reducing leakage.[68] The memo examines economic and emissions leakage in California and offers several recommendations to minimize leakage including linkage, banking/borrowing, multi-year compliance periods, offsets, limiting costly complementary measures and border adjustments. Notably missing is the direct recommendation that distribution of free allowances would prevent leakage. On the contrary, the memo says:

> "*Free allowance allocations that are fixed or independent of sources' decisions can compensate sources for reductions in asset values from GHG reductions policies, but they are unlikely to appreciably affect the extent of leakage…. Free, regularly updating allocation of allowances based on output levels can reduce leakage, but it can also distort incentives and increase the total costs of achieving GHG reduction goals…."*

Fifth, although the guarantee of emissions reductions under AB 32 is achieved by the declining overall emissions limit and not by auction of credits, it is well documented

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[65] See Appendix A for calculation explanation.
[66] See CARB PROPOSED AMENDMENTS TO THE CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS, September 4, 2013. http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf
[67] See Appendix B for calculation explanation
[68] See Analysis Group Comments on Leakage Memo, May 28, 2009. http://www.arb.ca.gov/cc/capandtrade/meetings/041309/apr13pcanalgrp.pdf

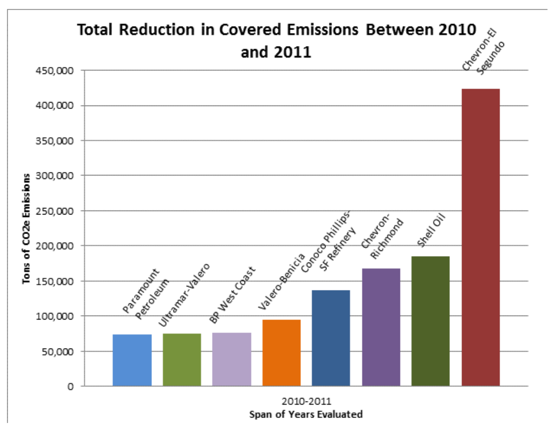
that auctions have an important role in making the overall program work effectively and protect Californians. A letter sent to Governor Jerry Brown by a group of 56 well respected economists clarifies this point:

> "*Whether an industry operates in a perfectly competitive market or otherwise, there is always the potential for windfall profits from free allocation. In most situations businesses are able to pass the market value of allowances through to consumers, even though they themselves received allowances for free. This is what happened in the EU's wholesale electricity market[69]. Short of fundamental market reform, the easiest step to reduce the potential for such undue profits is to auction allowances, a step the EU has since taken.*"[70]

While the electric utilities must buy their allowances and return revenues to the benefit of their ratepayers, under this proposed amendment, oil companies will continue to receive allowances for free, paid for by taxpayers, while simultaneously passing along the value of those credits as additional costs to their customers. Thus, refiners will get free credits and additional profit from increased prices at the pump. By getting a free pass, without any strings attached, refiners will have little incentive to invest in pollution reducing measures.

Sixth, recent petroleum refinery emissions data do not demonstrate a need for continued assistance in the second compliance period – transition is already occurring.

EDF analyzed CARB's recently released 2011 emissions data showing that 11 of the state's refineries logged significant reductions in their greenhouse gas pollution between 2010 and 2011 (see figure 1).[71] These reductions were not a result of facilities suspending or cutting production through voluntary or involuntary action, but rather investment in and upgrading equipment.



In support of EDF's analysis, a recently released CARB report shows the major energy efficiency investments are being pursued across the state's largest refineries.[72] In the report, CARB identified 401 energy efficiency opportunities that are completed, ongoing, scheduled or currently under consideration at the state's biggest polluters. In total, these

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[69] Sijm, Jos, Karsten Neuhoff, and Yihsu Chen, 2006. "CO2 co sector," Climate Policy, and Ellerman, Denny, and Paul L. Jo Trading System in perspective," Pew Center on Global Climate Climate and Energy Solutions).

[70] Joint Letter of Economists and Economic Experts to Governor Brown Relating to the Allowance Allocation Design of the California Cap-and-Trade Regulation, August 26, 2012.

[71] Koehler, Larissa, "Major California Refineries Logging Big Pollution Reductions Under AB 32" http://blogs.edf.org/californiadream/category/global-warming-solutions-act-ab-32/page/2/, February 12, 2013.

[72] CARB, Energy Efficiency and Co-Benefits Assessment of Large Industrial Soures, Refinery Sector Public Report, June 2013. Available at http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf

projects would reduce GHG emissions from the 12 facilities studied by about 2.78MMT CO2e annually, about 9% of their statewide total. In addition, these improvements would create individual net savings of up to $25 million annually. What's more, these savings estimates do not include the benefit these companies get from having to secure fewer allowances – worth another $ 50 million annually at a forecasted carbon price of $18/ton of carbon.

A prime example of the type of investment being made can be seen at Valero's refinery in Benicia, CA, which decreased covered GHG emissions by over 95,000 metric tons. As reported in the Benicia Herald, this decrease was the direct result of a new flue gas scrubber put into use at the refinery in 2011.[73] According to Sue Fisher Jones, public affairs manager for the Benicia refinery, the Valero installation,

> *"…will let the refinery retire existing furnaces, allowing new, energy-efficient furnaces to operate and reduce the refinery's greenhouse gas footprint*."[74]

Another prime example of the lack of need for transition assistance to refineries can be seen in corporate documents released by Tesoro related to the purchase of the nearby BP Wilmington refinery for $1,175 million. In support of the sale, Tesoro released the following statements, prior to any transition assistance modifications.

> *"Tesoro has a proven track record on the West Coast, and we understand the business climate and the challenging, but manageable, regulatory environment in California… Tesoro has invested over $1.7 billion in our West Coast facilities over the last five years… The transaction is expected to reduce stationary source air emissions, lowering AB 32 compliance costs…Reconfiguration of the refineries will increase transportation fuels production while decreasing Wilmington's CO2 emissions by 30%..."*[75]

In sum, CARB's justification for extending transition assistance is to allow for additional certainty and time for industry to invest in the low carbon production processes and further protect them from leakage and to ensure consumers are not negatively impacted by the Program. From this latest emissions report, and the points detailed above, because of the dominant position of oil refineries in California and their ability to pass through costs, it does not appear that the petroleum refinery sector needs more assistance via free allowances.

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[73] Weilenman, Donna Beth. "Refinery to Test New Scrubber." The Benicia Herald. N.p., 4 Dec. 2010. Web. 01 Aug. 2013.
[74] ibid
[75] See Tesoro Investor Summary: Tesoro Purchase BP's Southern California Refining And Marketing Business, Also See: Thomson Reuters Street events Edited Transcript TSO -Tesoro Corporation to Purchase BP's Fully Integrated Southern California Refining and Marketing Business -Conference Call EVENT DATE/TIME: AUGUST 13, 2012.

APPENDIX A: Oil Refinery Giveaway – Allowance Value Calculations Under Proposed Amendments.

A	B	C	D	E	F	G
	2011	2015	2015	2015	2015	2015
Facility Name	Emissions reported through MRR	Allowance giveaway under original TA schedule (75%)	Allowance giveaway under proposed TA schedule (100%)	Additional allowances from original TA schedule now proposed as giveaway	Price per allowance (middle scenario)	Cost of giveaway now proposed from original TA schedule
BP West Coast Products LLC, Refinery	4,357,243	2,776,435	3,701,914	925,478	$14.70	$13,608,772

Total cost of giveaway now proposed from original over all refineries (2015-2020) = $648,074,558

*TA = Transition Assistance

The above table demonstrates the methodology for calculating the petroleum refinery giveaway under the proposed transition assistance schedule. It shows calculations for the BP West Coast Products refinery as an example.

Explanation of items and calculations

- **Column A**: The refinery facility name.
- **Column B**: This is the most recent data reported by facility under ARB's Mandatory Greenhouse Gas Reporting program.[1]
- **Column C**: Allowance giveaway under the original schedule is calculated for year *t* according to the following equation (in this case, *t*=2015):

$$A_t = GHG_{2011} \times C_t \times 0.90 \times AF_t$$

where

GHG_{2011} = official reported emissions of refinery in 2011

C_t = cap decline factor for year *t*

AF_t = Industry assistance factor for year *t*

Year t	2013	2014	2015	2016	2017	2018	2019	2020
C_t	0.981	0.963	0.944	0.925	0.907	0.888	0.869	0.851
AF_t	1	1	0.75	0.75	0.75	0.50	0.50	0.50

Note: cap decline factors are those documented in the current regulation

- **Column D**: Allowance giveaway under the proposed schedule is calculated for year *t* according to the above calculation with the following industry assistance factors (in this case, *t*=2015):

Year t	2013	2014	2015	2016	2017	2018	2019	2020
AF_t	1	1	1	1	1	0.75	0.75	0.75

APPENDIX A: Oil Refinery Giveaway – Allowance Value Calculations Under Proposed Amendments.

- **Column E**: Subtracts value in column C from column D to arrive at the additional allowances that the refinery must purchase under the proposed TA schedule as compared to the original TA schedule
- **Column F**: Allowance price in the middle scenario is $2.50 above the floor price in 2015. The floor price was calculated starting with $10 in 2012. For each year after, the floor price was increased by 5% plus the rate of inflation forecasted, as is consistent with the regulation.[2]
- **Column G**: Multiplies value in column E with column F to arrive at the additional cost of the original TA schedule over the cost of the proposed TA schedule for BP West Coast Products in 2015, when the proposed change would take effect.
- **Total cost of giveaway now proposed over all refineries (2015-2020):** If the above analysis is repeated for all of the regulated refineries across all years of compliance periods 2 and 3, when the proposed regulation differs from the current regulation, then the total cost is the value highlighted. Therefore, this number represents the value of the additional allowances that will be given away through 2020 if the proposed regulation is adopted as compared to the current regulation. This is a mid-range estimate based on an allowance price that is $2.50 above the floor price. The model is available upon request.

APPENDIX B: Oil Refinery – Operating Profits Analysis Per Barrel of Gasoline

A		B	C		D	E		F	G	H
2012-2013			2012-2013			2012-2013		2013	2015	
Refiner costs and profits per gallon of gasoline		Gallons per barrel	Refiner costs and profits per barrel of gasoline		Refiner costs per barrel of gasoline	Refiner profits per barrel of gasoline		Throughput per year (90% capacity) (barrels)	Cost from original TA schedule now proposed as giveaway (middle scenario): Total	Cost from original TA schedule now proposed as giveaway (middle scenario): per barrel
Branded	Unbranded		Branded	Unbranded		Branded	Unbranded			
$ 0.46	$ 0.41	42	$ 19.47	$ 17.08	$8	$ 11.47	$ 9.08	659,355,674	$ 97,911,430	$ 0.15

Profit per barrel	$ 11.23	
Cost from original TA schedule per barrel	$ 0.15	1.3%

*TA = Transition Assistance

Explanation of items and calculations

- **Column A**: The values listed are the averages from the costs and profits data listed from January 2012 – August 2013 on the California's Energy Almanac website. [1]
- **Column B**: Conversion constant
- **Column C**: Values listed equal the product of columns A and B which calculate refiner costs and profits on a per barrel of gasoline basis. Branded = $0.46 per gallon of gasoline x 42 gallons/barrel = $19.47 per barrel of gasoline
- **Column D**: This is a conservative estimate. Note that the highlighted percentage is only mildly sensitive to this parameter within a wide range of values for the assumption of cost per barrel.
- **Column E**: Subtracts value in column D from column C to arrive at refiner profit per barrel of gasoline. Branded = $19.47 - $8 = $11.47
- **Column F**: Throughput is estimated at 90% of California refinery capacities as of October 1, 2012. Capacity data is also from California's Energy Almanac website.
- **Column G**: Total costs from the original TA schedule now proposed as the giveaway. This middle scenario assumes the allowance price is $2.50 above the floor price in 2015. This is the cost differential from current regulation to updated regulation with 25%
- **Column H**: Column G (value of giveaway) divided by Column F (number of barrels per year) to give a cost per barrel

[1] http://energyalmanac.ca.gov/gasoline/margins/

APPENDIX B: Oil Refinery – Operating Profits Analysis Per Barrel of Gasoline

- **Note about years:** Refiners costs and profits as well as throughput are based on latest available public data. The costs associated with the TA schedule changes are from 2015, since that's when the change would occur.
- **Profit per barrel:** Uses column E and percentage of capacities from branded refineries vs. unbranded refiners to calculate an approximate weighted average of profit per barrel based on capacity in 2011.
- **Cost from original TA schedule per barrel – highlighted percentage:** Divides profits per barrel by cost from original TA schedule per barrel and represents the cost as a percentage of the profits.
- **Note:** these calculations are based on gasoline data, whereas similar analysis can be performed for the other refinery products from crude. Gasoline represents approximately 50% of the product from crude, whereas the remaining products are aviation, distillate and residual fuel. [2] Also, we acknowledge that these calculations are with respect to the short-term variable costs. However, even if we were to account for fixed costs, we assume that those would be paid back to the refineries eventually in annual energy savings.

Narrative explanation of model

Using publicly available data from California's Energy Almanac, we calculated that California refinery costs and profits per barrel of gasoline to be approximately $18 on average during 2012 and 2013 to date. For the purpose of attempting to isolate the portion of this $18 which is profit, one may use a high end estimate of refinery costs of $8 per barrel, thus giving an approximate profit of $10 per barrel profit on average across refineries. In contrast, the total value of the allowances which the original transition assistance schedule called for refineries to pay for, but the proposed schedule aims to give away for free, amounts to just a fraction of this profit, likely less than $0.20 per barrel. These estimates are based on the model described in Appendix A, which estimates the total give away value through 2020 to be between $550 and $750 depending on future price per allowance. Thus to put these costs from the original transition assistance schedule in perspective, per barrel of gasoline, they are likely between 1% and 2% of profits for these refineries.

[2] http://energyalmanac.ca.gov/petroleum/refineries.html

(EDF 1)

Comment: (Summary) Greenlining strongly opposes staff's proposal to extend transition assistance and specifically doesn't like extending transition assistance to refineries. ARB has provided no evidence supporting extending transition assistance. (GI)

Comment: (Summary) NRDC and Coalition for Clean Air strongly opposes staff's proposal to extend transition assistance and specifically doesn't like extending transition assistance to refineries. ARB has provided no evidence supporting extending transition assistance. Further this may lead to windfall profits. (NRDC 2)

Comment: ARB should give equal consideration to the risk of overcompensating covered entities as it currently gives to leakage risk. (APEN, GAIA)

Comment: ARB should not extend transition assistance in lieu of requiring the industrial sector to purchase allowances at auction. ARB. must provide sufficient supporting analysis prior to extending transition assistance. (APEN, GAIA)

Comment: First, the proposal to dramatically increase free allocation to industry for leakage prevention on the basis of no evidence that additional assistance is required.

First on transition assistance. This is a small change on paper. Simply shifting one number in allocation formulas for industry with a huge impact. On the order of 60 million allowances by 2020, which could be upwards of a billion dollars. The lion's share of that is going to the cash strapped oil industry, which somehow found $43 million to lobby in Sacramento alone since 2009 but hasn't found the time to invest in emission reductions.

What has been the industry response? More, please. More, please. Already, the lobbying has begun to extend transition assistance against in the third compliance period. Who can blame them? As long as stall, delay, and obstruction continue to earn reward, that's only a rational response.

We ask the Board to instead uphold its commitment to transitioning toward allocating allowance value through an auction process that is open to all comers, transparent, and ensures the benefits of allowance value accrue to all Californians. (NRDC 4)

Comment: (Summary) There is one element of today's package that creates tremendous concern for us. That is the extension of transition assistance to the refining sector. We believe that this decision is premature as research has not been finalized to demonstrate its necessity. In fact, WSPA's own analysis found that 100 percent transition assistance is unnecessary, not to mention that it won't make much of a difference to these very large petroleum companies. We urge the Board to reject this extension of transition assistance. (EDF 2)

> **Response:** ARB declines to make any changes. Transition assistance is meant to reduce the potential for leakage. If production shifts outside of California to a region not subject to GHG emissions-reduction requirements, emissions could

remain unchanged or even increase. This “emissions leakage” is counterproductive to the goals AB 32 and ARB’s Cap-and-Trade Program. Treating refineries differently than proscribed in the leakage risk methodology established in the Regulation for all industries covered under the Cap-and-Trade Program would be arbitrary and could lead to many complex exemptions and requirements for each industry.

ARB staff included transition and leakage prevention assistance levels in the initial Regulation based on state-of-the-science methodologies and best available data. This analysis indicated that refineries and other industry sectors were at risk of emissions leakage and that it was appropriate to allocate allowances to these sectors. However, measuring leakage at the State level is challenging due to lack of publicly available information regarding trade flows across State borders and State-level economic data within an industry. To this end, ARB staff has put in place research contracts to develop analytical tools and assess newly available data to refine the leakage risk assessment and monitor for leakage. The research is not expected to conclude until at least after the first year of allocation has occurred for the second compliance period.

Due to the critical importance to the health of the economy of California, and of addressing the GHG emissions reduction goals of AB 32, it is necessary to err on the side of reducing leakage pressures while ARB staff awaits the results of its research efforts. This will provide these sectors and the market with certainty about levels of free allocation through the second compliance period.

C-1.5. Multiple Comments: ARB should not give any free allowances to provide certainty that the value of allowances will be used for the benefit of consumers and to further the purposes of AB 32 and to avoid rewarding industry stalling, delay, and obstruction. Leakage risk should be subject to independent 3rd party analysis. (APEN, GAIA)

Comment: We oppose the continued give-away of allowances to the industrial sector. The primary beneficiaries are the big oil companies. These are among the biggest polluters in the state and among the most profitable companies in the entire world. The Expert Economic Advisory Committee that ARB charged with advising on the allocation process recommended auctioning virtually all the allowances and specifically warned against over allocating the transition allowances. We, of course, agree that you need to minimize leakage. That's a good idea. It's required by AB 32. But in this case, there's been no demonstration that these facilities are at risk for leakage. So we urge you to end that transition assistance and not give away this valuable public asset that the value of which should be used for the benefit of the public, not for those companies. (CCA, ALA)

Response: ARB staff agrees that auction is the fairest and most transparent means of distributing allowances. ARB staff recognizes that the long-term success of the program will require significant investment in emission reductions.

However, freely allocating allowances in the early years of the program as transition assistance will help prevent emissions leakage. Allocating the allowances for free using emissions-efficiency benchmarks will reward companies that have already made investments in energy efficiency and emissions reductions, and will not penalize those that produce goods in California, while the cap ensures that emissions reductions will continue to occur.

ARB staff included transition and leakage prevention assistance levels in the initial Regulation based on state-of-the-science methodologies and best available data. However, measuring leakage at the State level is challenging due to lack of publicly available information regarding trade flows across State borders and State-level economic data within an industry. To this end, ARB staff has put in place research contracts to develop analytical tools and assess newly available data to refine the leakage risk assessment and monitor for leakage. The research is not expected to conclude until at least after the first year of allocation has occurred for the second compliance period.

Due to the critical importance to the health of the economy of California, and of addressing the GHG emissions-reduction goals of AB 32, it is necessary to err on the side of reducing leakage pressures while ARB staff awaits the results of its research efforts. This will provide these sectors and the market with certainty about levels of free allocation through the second compliance period.

C-2. Leakage Risk Classifications

Liquid Hydrogen

C-2.1. Comment: (Summary) Liquid hydrogen production industry should be assigned the high leakage risk designation. (APC 1)

Response: ARB staff is investigating the feasibility of disaggregating gaseous and liquid hydrogen with respect to leakage risk analysis. This analysis is not expected to conclude prior to the beginning of the second compliance period. Because industry assistance factors have been maintained at 100% for all leakage risk categories through the second compliance period, this delay in reassessing the leakage risk for liquid hydrogen should not result in any increased leakage risk to this industry.

Food Manufacturing

C-2.2. Comment: (Summary) We strongly believe that a closer look needs to be taken at our industry on the issue of leakage risk classification. Food processors are already faced with cost increases in multiple areas including water supply and quality, pesticide management, and the administrative expense of ensuring regulatory compliance. Thus, we are encouraged by the further study that ARB is currently undertaking on the food processing industry. Thus, we are encouraged by the further study that ARB is currently undertaking on the food processing industry. (WGA)

Response: Thank you for the support.

Mineral Wool Manufacturing

C-2.3. Multiple Comments: (Summary) NAIMA strongly urges the Board to adopt the CARB's staff recommendation to change the leakage risk classification for Mineral Wool Manufacturing based on the clearly demonstrated risk of domestic leakage. The credibility of CARB's conclusion is strengthened by the fact that similar trends were not found in other sectors for which public data was available. CARB has not initiated a widespread trade exposure (TE) reclassification, but has restricted it to this one instance where the data supported such an action. NAIMA greatly appreciates the effort and work that CARB staff spent on its reanalysis of the TE data. (NAIMA 1)

Comment: We just want to drive home the Johns Manville support for the staff recommendation to move our industry category from a medium risk to a high leakage risk category. And as explained in the NAIMA comments, there are two principle reasons for this. One is the presence of many additional fiberglass building insulation manufacturing locations in the western United States, including just outside the border of California.

And the other reason that's explained in detail in the written comments is the continuing generally low level of capacity utilization in the fiberglass building insulation industry. This is due to unfortunately the continuing low level of new housing starts in the United States. So ask that you support the staff recommendation in this regard. And unless you have any questions, I thank you for letting me address you. (MANVILLE)

Response: Thank you for the support.

C-2.4 Comment: (Summary) When the assistance factors were assigned, fiberglass was only given 100 percent the first [compliance period], and then second and third we were significantly reduced. We went in and we sat down with the California Air Resources Board and explained to them domestic leakage was far more relevant than foreign leakage. What was very gratifying is California Air Resource Board heard us. They listened to us. They understood what we were saying and we are now here supporting the changes that have been made. (NAIMA 2)

Response: Thank you for the support. The adjustment to the leakage classification for the mineral wool manufacturing sector was made to reflect the changing trade exposure of this sector as demonstrated in Appendix B[76] to the ISOR for this regulatory amendment package.

[76] Available at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappb.pdf

Polystyrene Foam Manufacturing

C-2.5 Comment: Section 95870(e)(2) provides an allowance allocation to eligible covered entities in Table 8-1. Proposed Section 95891(a)(3) allows opt-in of entities with the first three digits the same as Table 8-1 to receive an allocation of allowances. Table 8-1 should be modified to include Polystyrene Foam Product Manufacturing, NAICs Code 926140. The ARB leakage analysis in appendix K to the ISOR in 2010 and the adopted cap-and-trade regulation in 2010, included this industry as subject to leakage. However, the 2011 adopted regulation deleted the industry without explanation. Even if the single firm in Polystyrene Foam Product Manufacturing; NAICs 926140, is no longer operating in California, the industry should be added back so that other entities in NAICs 926 would have the ability to opt-in to mitigate leakage risk. (SEMPRA 2)

> **Response:** The ARB leakage risk analysis policy is to include a leakage risk categorization in Table 8-1 of the Regulation for any industrial sectors that have covered entities which meet the emissions inclusion thresholds as described in section 95812 of the Regulation, or opt-in covered entities as described in section 95813 of the Regulation. While ARB staff conducted a leakage risk analysis for Polystyrene Foam Product Manufacturing, North American Industry Classification System (NAICS) sector 326140, that was included in Appendix K of the 2010 Cap-and-Trade Regulation, its leakage risk categorization was not included in Table 8-1 of the Regulation because there were not any entities meeting either of the above criteria at the time the Regulation was adopted.

Refineries

C-2.6 Multiple Comments: On top of creating in-state competitive issues, any cost burden added to a California refinery makes it less competitive versus refineries outside California who can import into California without cap and trade compliance costs. Without any protection from the import of finished or intermediate products, and with real world barge shipping costs to import fuel averaging out at only 3-6 cents per gallon, P66 recommends that CARB step back and take a fresh look at what the staff is proposing from in-state refining. (PHILLIPS 1)

Comment. California has a strong tradition of demonstrating that a healthy environmental and strong economy can work hand in hand. And we are confident it can do the same with the Global Warming Solutions Act. We would like to see more effort at addressing imports of intermediates and finished fuel products into the state. CARB needs to create a mechanism which provides an obligation for all entities importing petroleum and non-petroleum transportation fuels equal of those in-state refiners currently regulated as station source GHG emitters.

Currently, only in-state refineries are obligated to pay for stationary source GHG emissions. To prevent leakage of GHGs emissions associated with the manufacture of petroleum and intermediates to out-of-state refineries, a program must be put in place.

Until such time, the typical benchmark required for larger refineries must remain fair, allowing reductions equally from every facility.

I work for Phillips 66 oil refinery.   I represent as a union leader all of the oil refiners in L.A. basin. We are not interested in losing any more of our California refiners in this state. The USW has supported the Global Warming Solutions Act and AB 32 from the very beginning. I was a statewide coordinator for that program for the USW in California. The reason that we were able to support it so unilaterally was because we believed it was going to create a strong economic, new green workforce development in California. If we lose jobs as a result of this, it doesn't take care of those needs we have in terms of job creation and reducing emissions. Thank you. (USW 1)

> **Response:** Controlling leakage while addressing the GHG emissions-reduction goals of AB 32 is of critical importance to the health of the citizens and economy of California. ARB staff included transition and leakage prevention assistance levels in the initial Regulation based on state-of-the-science methodologies and best available data. However, measuring leakage at the State level is challenging due to lack of publicly available information regarding trade flows across State borders and State-level economic data within an industry. To this end, ARB staff has put in place research contracts to develop analytical tools and assess newly available data to refine the leakage risk assessment and monitor for leakage. The research is not expected to conclude until at least after the first year of allocation has occurred for the second compliance period.
>
> As directed by Board Resolution 10-42, ARB staff is investigating the feasibility of a border adjustment to address leakage concerns for the cement sector. Upon concluding these efforts, ARB staff will investigate whether border adjustments may also be used to ensure that the emissions associated with the processing of transportation fuels imported into California are covered under the program, thereby further protecting against leakage.

C-2.7. Multiple Comments: Alon understands that additional leakage analysis is being conducted by the Board, and seeks recognition that Asphalt refineries are unique and therefore should be addressed accordingly in the future. We note that much of the leakage in the asphalt production sub-sector has already occurred. (PARAMOUNT 1)

Comment: The issue of asphalt refiners and their potential emission leakage has been on the table and a point of discussion for several years but CARB has done little to address the issue directly. The proposed amendments take a small step to address this problem with the addition of a new activity category in Table 8-1 focused on asphalt batch plants. Alon is disappointed that CARB missed an opportunity to finally address this issue. Batch plants need to be located in the areas they serve, whereas refined asphalt product can be shipped in from faraway locations-with an increase in GHG transportation emissions. The true leakage risk is at the refinery level.

We understand that CARB currently is studying leakage risks for various sectors and activities with the goal of further amending Table 8-1 at a later date. Alon recommends adding a new specific activity categorization for Asphalt Refineries in Table 8-1 as well as, a review of a potential new asphalt benchmark. This result would be consistent with other industries that have product specific benchmarks, such as cement manufacturing. Without individual recognition, Asphalt refiners will otherwise be unfairly competing in the marketplace against BOTH dedicated petroleum refiners and cement manufactures. Leakage in this sector has already occurred. Whereas Alon used to be the largest manufacturer of asphalt in California, it is now one of the largest importers of bitumen which we convert to a variety of value added products, including asphalt. This issue needs to be addressed in future rulemakings. (PARAMOUNT 1)

Comment: I'd also like to comment on the refiner leakage risk. Much of the bitumen used to grease asphalt today in California is imported from mid-continent rail, the resulting increase CO2s emission. These refineries should be considered at high risk of leakage since much of it has already leaked from the state. Asphalt refineries in contrast to the big bubble refineries compete in two industries: Fuels and materials. Although we believe our polymer road asphalts which effectively sequester crude oil make the smoothest quietest highways. We must compete on price with cement manufacturers who have the highest allocation factors and special adjustment. (PARAMOUNT 2)

> **Response:** At the request of the petroleum refining sector, ARB staff worked with refineries to develop a complexity-weighted barrel (CWB) benchmark for refinery allowance allocation. This CWB benchmark includes a factor that allocates for asphalt production. Because this CWB benchmark accounts for a broad range of petroleum refinery products, it is appropriate to assess the leakage risk for these products based on the petroleum refinery NAICS code (324110). ARB staff continues to study and monitor leakage and welcomes data sharing from industry that can inform leakage analyses and classification efforts.

Leakage Risk Classification for New Entrants

C-2.8 Comment: We are very grateful particularly for the increase in the industry assistance factor. And I'm here to talk specifically about the leakage risk classification for new entrants. We're grateful that new entrants have an opportunity to have a leakage risk classification factor assigned to them. If they're not currently in the program, and they come in and are not listed in Table 8.1 but they have the first three digits of a NAICS code in that table, they will be put into the low leakage risk classification.

This is helpful to an extent because they are able to get an industry assistance factor. But we are concerned because there's language that states that they'll be in the low leakage risk classification until a leakage risk classification is added for that sector. And we'd just like a bit more clarity on how factor will be assigned to that sector with the process going forward. This presents a concern for industry that is considering increasing production in California, whether they become a new entrant and how they will be treated and how many allowances they all be allocated. (ALSTON)

Response: ARB staff declines to make this change. Putting a new entrant whose industry's NAICS code has not been previously evaluated for leakage risk into a low leakage risk category allows for that facility to be eligible for some level of free allocation while ARB staff has an opportunity to evaluate that facility's NAICS sector for leakage risk. This protects against over allocation while at the same time providing some level of industry assistance to reduce the possibility of leakage for this facility.

D. COVERED SECTORS AND EXEMPT EMISSIONS

D-1. Exempt Emissions

Combined Heat and Power and District Heating

D-1.1. Multiple Comments: The limited exemption offered to "but for" CHP facilities (i.e., those facilities whose CHP operations push the site over the emissions compliance threshold of 25,000 metric tons CO2e) represents a correction of incentives for CHP and an equitable balance of environmental integrity of the cap-and-trade program and equal treatment for industrial facilities with and without CHP. (SCE 1)

Comment: Central Contra Costa Sanitary District (CCCSD) appreciates the opportunity to comment on the proposed amendments to the California Air Resource Board (ARB) Cap and Trade Program with respect to "but for" combined heat and power (CHP) facilities. CCCSD fully supports the proposed amendments and believes it will result in a net reduction in greenhouse gas (GHG) emissions.

CCCSD, a wastewater treatment plant located in Martinez, California, provides treatment of approximately 45 million gallons per day of wastewater to 462,000 residents and businesses in Central Contra Costa County. Our goal is to protect the public health and provide wastewater treatment at responsible rates. CCCSD operates a CHP Cogeneration unit that combusts natural gas to generate steam and electricity for the treatment plant. The steam produced by Cogeneration is used to drive the steam turbine that provides power to the aeration blowers for the secondary treatment process. The combustion of natural gas in Cogeneration reduces overall GHG emissions and offers a twofold benefit of electric and thermal energy recovery.

Currently, CCCSD is importing electricity from the grid to remain under the threshold for inclusion in the Cap and Trade Program. Under the proposed regulations, CCCSD would be able to operate Cogeneration at maximum output to provide a reliable and cost-effective source of steam and electricity for the treatment plant while reducing overall GHG emissions.

Under the current regulations, facilities have an incentive to cease operation of their CHP facility and import electricity from the grid to reduce their compliance obligation with the Cap and Trade Program but the net result is an increase in overall GHG emissions. The proposed amendments exempting those emissions from CHP that result in useful thermal energy (i.e. 150 psig steam) would allow facilities with CHP to reduce overall greenhouse gas emissions and produce energy, both electric and thermal, more efficiently while supporting the long-term goals of the Cap and Trade Program.

In 2015, natural gas suppliers will be subject to comply with the Cap and Trade Program. This will drive up prices for both natural gas and Cap and Trade compliance instruments. To minimize the impact on CHP facilities, CCCSD strongly suggests this exemption be extended into the second compliance period (2015- 2017). (CCCSD 1)

> **Response**: ARB staff appreciates the commenters' support for the amendments. ARB staff has modified the proposed amendments to extend the exemption through the second and third compliance periods.

D-1.2. Comment: We were caught a little unaware by Resolution language on "but for" CHP. It appears that compliance obligation is going to shift back to the utilities. We'll work with staff, but this morning is the first we saw of it. (PGE 3)

> **Response:** During the second and third compliance periods, natural gas suppliers will have compliance obligations for and receive allocations based on the amount of natural gas they supplied to end users in 2011 that are not covered entities. This amount of natural gas will include natural gas supplied to "but for" facilities since they are not covered entities. Natural gas suppliers do not have a compliance obligation during the first compliance period.
>
> Each natural gas supplier's allocation is based on its emissions in 2011 as calculated in Section 95852(c)(4) (emissions from deliveries of natural gas less emissions from deliveries to covered entities). Section 95852(j) clarifies that "but for" CHP facilities will not be considered covered entities so their emissions would be part of the 2011 compliance obligation and subsequent allowance allocation. If a "but for" CHP facility's emissions increase, rendering it ineligible for a limited exemption, then its emissions would be removed from the natural gas supplier's 2011 compliance obligation calculation that feeds into the annual allocation.

D-1.3. Multiple Comments: Qualcomm requests that our early actions in energy efficiency and CHP investments leading to permanent greenhouse gas reductions, as well as our RPS investments be recognized by CARB. We seek to be treated on a level playing field with other entities who have received allowances beyond 2015 to help the state meet its cap-and-trade implementation goals.

Below are Qualcomm's comments related to the "But For" Combined Heat and Power (CHP) Facilities, consistent with our previous comments in response to the staff discussion draft and workshop.

1. Application for "Qualified Thermal Output" Exemption (Section 95852(j)1 and 4). Qualcomm believes an application process is not necessary for the exemption because CARB would already have this data, either from previous submissions, or from current (2013) estimates provided by CHP facilities. The draft language in this section is too vague and does not state what the process is to apply for an exemption, nor does it address how long it would take CARB to grant the exemption. Our main concern is that a drawn out application, review and approval process may force us to have to

unnecessarily incur significant costs to purchase allowances in order to meet the current CARB requirements, while waiting for CARB to grant the exemption.

2. Transition Assistance for the Second and Third Compliance Periods (2015 – 2020). Many entities will receive transition assistance in the first, second and third compliance periods. Board staff have argued that providing entities such as Qualcomm with free allowances after 2015 would put Qualcomm at a competitive advantage by lowering their carbon costs relative to other covered entities. Qualcomm feels that the opposite is true.

Generators of electricity are expected to pass their compliance cost to the utilities purchasing their power under the Board's regulations. While these generators do not receive an allowance allocation to mitigate this additional cost, the utilities that they sell to do. These electric utilities are allowed to use their allowance value to mitigate the increased carbon costs that their customers would otherwise face via rate increases. The power that Qualcomm's CHP facilities generate on-site is used on-site, not sold back to the grid. As such, without transition assistance after 2015, Qualcomm will be forced to absorb its carbon costs while other generators can pass these costs to their customers, and the utilities are given allowances to mitigate carbon costs that are passed to their ratepayers.

At the same time, the Board's regulations force Qualcomm and other "but for" entities to pay a relatively higher cost per ton of carbon emitted than other covered entities. Other industrial covered entities will continue to receive some free allowances from the Board after 2015, thus only having to purchase a portion of the allowances needed to meet their compliance obligation. Qualcomm and other "but for" entities must purchase every allowance needed to fulfill their compliance obligation. In summary, while other industrial entities must only pay for some of their emissions, Qualcomm and other "but for" entities are being asked to pay for every single ton of GHG emitted.

Qualcomm believes a more equitable solution has been struck for "but for" entities who are also public universities. These entities will be given allowances based on a formula in the proposed regulatory amendments. Qualcomm does not agree that a separate solution should be applied to similar covered entities.

The Cap-and-Trade program is designed to recognize and compensate covered entities for their early action. Qualcomm's early use of CHP allowed it to generate its own energy more efficiently, thus offsetting the need to use less efficient and more carbon intensive energy from the grid. By choosing not to provide "but for" entities like Qualcomm with transition assistance after 2015, the Board is creating a perverse incentive for Qualcomm and other entities to reduce or discontinue its use of CHP entirely, thus increasing GHG emissions. As such we urge the Board to take action to provide equitable treatment to "but for" entities like Qualcomm by providing them with transition assistance in the form of free allowances after 2015. (QUALCOMM 1)

Comment: My name is Gail Welch. I'm with Qualcomm telecommunication company headquartered in San Diego, California. We submitted comments online.
We are in the Cap and Trade Program because of our investment in combined heat and power to power our campus offices, labs, and data centers. We came here today looking actually to address the 2013 and '14 first compliance period exemption on but for CHP, which as you know has been recognized for industrial energy Efficiency and reducing greenhouse gases. Our regional intent was to tell you for the issue of allowances beyond 2015, we felt it was necessary to treat all but for CHP equitably whether it was a public university, public or private entity.

This morning, we did find out that the CARB will not be adapting the reg as proposed and just released some amendments that would we feel extend the uncertainty as CARB continues to work a solution. We would like to work more closely with you to better understand the impact of today's amendment that was released. And we continue to be concerned until the regs are adopted particularly for the near term 2013 the uncertainty may force us to unnecessarily incur a significant cost to purchase allowances in order to meet our current CARB requirements.

As the registration currently stands, we are as well as other but for CHP facilities covered entities without an allowance allocation. With respect to 2013-14, we appreciate CARB providing a patch for these but four facilities for the first compliance period through the limited exemption for thermal emissions, but we feel this doesn't solve the issue for Qualcomm and other but for entities. One of the reasons is because the formula only works for smaller CHP systems and actually discourages CHP investment to meet additional new growth.

Our other concern with 2013 is with requiring the application process. We addressed this in our comments. We feel CARB already has this information from our annual reporting to approve entities for the exemption.

I would like to point out that the California Clean Distributed Generation Coalition has submitted comments online in support of our comments here today. And in closing, we urge CARB to respond to our concerns and in particular to provide an equitable solution to provide allowances beyond 2015 to all but four entities, whether public or private, who have demonstrated early action and energy Efficiency in reducing greenhouse gas. Thank you. We look forward to increased communication with the Board, the staff. And thank you for your time. (QUALCOMM 2)

> **Response:** There are several reasons why an application is necessary. First, some “but-for” facilities may be eligible for industrial allocation. These entities may choose to either apply for the exemption, in which case they must give up their industrial allocation, or they may keep their industrial allocation instead of applying for the exemption. The application is needed to allow these entities to make their intentions clear to ARB staff. Furthermore, the exemption is based on analysis of data going back to 2008. The 2008 data were not verified, and some potential applicants appear to have made errors in early reporting. Further, the

definition of qualified thermal output was not applicable to MRR for 2008-2012 data year reporting. For these reasons, ARB requires an application process in order to identify which facilities are eligible for this exemption.

The commenter is concerned that under the originally proposed amendments, the exemption for “but-for” facilities is only for the first compliance period, and believes that such facilities should receive allowances through all three compliance periods as do universities and entities with industrial allocations. ARB made changes in the 15-Day Modifications that extend the exemption through the first three compliance periods. This is parallel to the allocation proposed to be provided for universities. “But for” facilities will ultimately face an indirect compliance cost as natural gas utilities phase in costs into rates. This means that they will be treated like other relatively small natural gas burning facilities that gradually face indirect GHG costs through gas rates.

D-1.4. Comment: Similarly, ARB has not addressed the important benchmark issues CCDC has raised, or CCDC's related concern that CHP will bear an economic penalty under Cap-and-Trade, which is contrary to policies that recognize CHP's benefits, including the potential to reduce GHG emissions, and sends the wrong market signal to existing and prospective CHP adopters. CCDC has attached its prior comments regarding benchmark issues to this letter, and requests that ARB consider and address them in any revisions to the Cap-and-Trade Regulation. We look forward to working with ARB to resolve these important issues.

CCDC sees value in some of the revisions relating to CHP, however, CCDC remains concerned that unless important benchmark issues are addressed, CHP will be forced to bear an economic penalty, which is contrary to longstanding policy supporting CHP, and diminishes the value of CHP as a GHG emissions reduction energy efficiency measure, as defined by ARB in the AB 32 Scoping Plan. CCDC urges ARB to modify the draft revisions to the Cap-and-Trade Regulation as proposed herein to maximize CHP's GHG emissions reduction potential for California.[77] All references to CHP in these comments include CHP that is owned by the customer or by a third party.

<u>Comments from the California Clean DG Coalition Regarding May 1 ARB Staff Workshop on CHP and Cap & Trade</u>

The California Clean DG Coalition ("CCOC") appreciates the opportunity to provide these comments regarding the California Air Resources Board's ("ARB") Staff Workshop on May 1, 2013 to discuss adjustments to the Cap and Trade Program for Universities and Combined Heat and Power ("CHP"). CCOC is an ad hoc group interested in promoting the ability of distributed generation ("OG") system manufacturers, distributors, marketers and investors, and electric customers, to deploy OG. Its members represent a variety of DG technologies including combined heat and

[77] Additional detail is provided in the CCDC Comments Regarding May 1 ARB Staff Workshop in CHP and Cap-and-Trade. That letter is incorporated herein by reference.

power ("CHP"), renewables, gas turbines, micro-turbines, reciprocating engines, and storage. CCDC is currently comprised of Capstone Turbine Corporation, Caterpillar, Inc., Cummins Inc., DE Solutions, Inc., GE Energy, Holt of California, NRG Energy, Penn Power Systems, Peterson Power Systems, Recycled Energy Development, SOP Energy, Solar Turbines, Inc., and Tecogen, Inc.

The California Clean DG Coalition ("CCDC") appreciates the opportunity to provide these comments regarding the California Air Resources Board's ("ARB") Staff Workshop on July 18, 2013 regarding the "discussion draft" of proposed changes to the Cap-and-Trade Regulation. CCDC is an ad hoc group interested in promoting the ability of distributed generation ("DG") system manufacturers, distributors, marketers and investors, and electric customers, to deploy DG. Its members represent a variety of DG technologies including combined heat and power ("CHP"L renewables, gas turbines, microturbines, reciprocating engines, and storage. CCDC is currently comprised of Capstone Turbine Corporation, Caterpillar, Inc., Cummins Inc., DE Solutions, Inc., GE Energy, Holt of California, NRG Thermal, Penn Power Systems, Peterson Power Systems, Recycled Energy Development, Solar Turbines, Inc., and Tecogen, Inc.

Among other things, Resolution 12-33 called for a transitional exemption from the Cap-and-Trade Program for "but for" CHP. ARB Resolution 12-33 called for revisions to the Cap-and-Trade program to recognize the GHG emission reduction value and other benefits of CHP. Resolution 12-33 specifically provides: WHEREAS, the Cap-and-Trade Program should reward existing and incentivize new efficient distributed electricity generation technologies, such as [CHP]; (Emphasis added.)

The important direction provided in Resolution 12-33 to reward existing and incentivize new efficient CHP should overlay any and all CHP-related revisions to the Cap-and-Trade Regulation. It clearly supports the revisions proposed herein.

ARB staff also proposes that the Cap and Trade first compliance period threshold for entities with CHP should be based on either steam emissions or electricity emissions exceeding 25,000 MTC02e, which keeps entities from triggering Cap and Trade only because of efficient CHP. We agree with the proposed methodology. However, CCDC recommends that the offsetting boiler efficiency assumption be changed from 85% to 80% which is a more realistic value for present day facilities serving large steam loads. We also recommend that the words "useful heat" be substituted for "steam," as steam is not always the heat transfer medium in a CHP system.

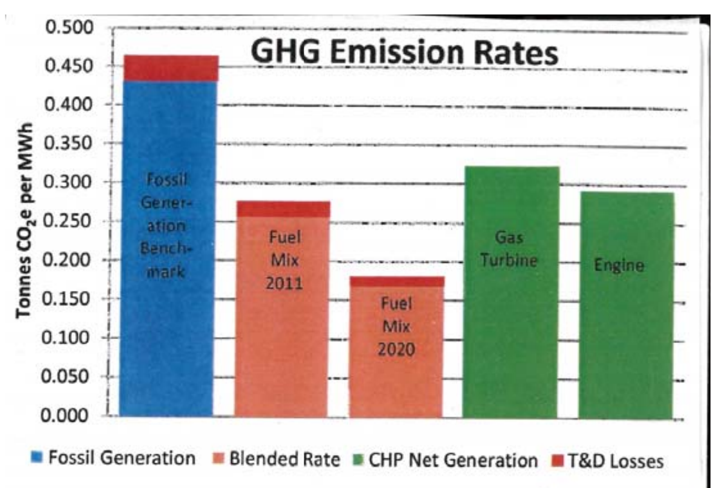
The "but for" CHP patch applies to an estimated 11 entities and does not go beyond the 1st compliance period. ARB stated that in the 2nd compliance period, all CHP facilities, whether through Cap and Trade or through a carbon adder in the price of natural gas, will be on the same economic playing field and Cap and Trade will improve the incentive for CHP. CCDC disagrees with this statement. ARB recognizes that efficient CHP displaces less efficient wholesale fossil generation sources from the California grid. The ARB emissions benchmark is 0.431MTC02e/MWh.[78] However, because the grid is not

[78] This corresponds with a 42% efficient natural gas plant

comprised of 100% natural gas power, the true economic linkage between the carbon cost adder in natural gas and the carbon cost adder in electricity does not exist.

CA Fuel Mix	2011 CEC	2020 Estimate	Emission Benchmark MTCO2/MWh	
Natural Gas	35.6%	34.0%	0.431	
Nuclear	15.3%	15.0%		
Eligible Renewables	14.2%	33.0%		
Coal	8.2%	0.0%	0.892	
Large Hydro	13.0%	13.0%		
Unspecified	13.7%	10.0%		
1/2 Natural Gas	6.9%	5.0%	0.431	
1/2 Large Hydro	6.9%	5.0%		
Total	100.0%	100.0%		Electric Price to C02 Benefit Ratio
Fossil Total	50.7%	39.0%		
Natural Gas Total	42.5%	39.0%		
CA Fuel Mix 2011			0.256	$900
CA Fuel Mix 2020			0.168	39%

According to the California Energy Commission, fossil power generation comprised 43.8% of the State's energy mix in 2011[79]. And of the 13.7% unspecified fuel sources, we assumed that one half was natural gas and the other half was large hydro. As shown in the figure to above, this mix corresponds to a blended delivered emission rate of 0.256 MTC02e/MWh, 41% less than the true benchmark. Based on an estimate of the fuel mix in 2020, the blended emission rate is 61% less than the true benchmark. The chart below compares the emission impact of these various emission weighting approaches against two typical CHP systems. As shown, CHP's GHG emission benefit goes from a positive when compared against the ARB electricity benchmark to a negative when compared against the whole fuel mix comprising California's wholesale electric grid.



[79] http://energyalmanac.ca.gov/electricity/total_system_power.html; unspecified power are generally out of state short term power purchases from plants that do not have a contract with a California utility Northwest spot purchases are served by surplus hydro and gas-fired power plants. The Southwest spot market purchases are primarily combined cycle power.

The table below compares the economic value of CHP to the State at allowance costs of $10 and $40 per tonne against the economic cost to CHP users when allowance costs for fossil generation are blended in to the electricity price along with non-fossil sources. As shown, the difference between the cost and the value exceeds 1.0 cent/kWh in 2020 if allowance costs hit $40/tonne.

	Value $/kWh		2011Cost $/kWh		2020 Cost $/kWh		Cost-Value 2020	
C02 Cost $/tonne	Turbine	Engine	Turbine	Engine	Turbine	Engine	Turbine $/kWh	Engine $/kWh
10	$0.0014	$0.0017	$0.0005	$0.0002	$0.0014	$0.0011	$0.0028	$0.0028
40	$0.0056	$0.0069	$0.0019	$0.0006	$0.0057	$0.0044	$0.0113	$0.0113

Forcing CHP to absorb an economic penalty because of Cap and Trade sends the wrong market signal to existing CHP adopters who expected a positive benefit from AB 32 and to prospective CHP adopters who will question the "green" in CHP and face uncertain economic consequences as the future price for allowances are unknown. CCDC views this as an inadvertent yet fundamental flaw in the treatment of CHP in California's Cap and Trade Program. Many prospective CHP projects are now stalled in the development pipeline due to this dilemma. If this problem is not corrected, we are concerned that ARB's reliance on CHP as a GHG reduction measure, including estimates for future CHP, will be seriously compromised. In addition, CHP provides additional environmental, efficiency, reliability, economic and jobs benefits that will be lost if CHP adopters risk penalties for their investment. These benefits are reason enough to ensure CHP investment is encouraged.

Cap-and-Trade Does Not Create a Level Playing Field for CHP. The State needs to true-up the effective carbon price adder paid for on-site CHP natural gas to mirror CHP's CO_2 benefit relative to CARB's electric benchmark. Possible solutions to this important issue could include the following:

- Payments to CHP owners from Cap and Trade Auction proceeds or the Natural Gas Allowance Revenue Fund
- Issuance of Allowances for CHP fuel

CCDC urges CARB and, as appropriate the CPUC, to fix this inequity as soon as possible so that CHP can live up to its GHG mitigation potential.

ARB has indicated that beginning with the second compliance period, all CHP facilities, whether as covered entities or through a carbon adder in the price of natural gas, will be on the same economic playing field and that Cap-and-Trade will actually provide an incentive for efficient CHP. CCDC continues to disagree with this concept, for the detailed reasons provided in its comments on the May 1 Workshop. CCDC reiterates its recommendation the State true-up the effective carbon price adder paid for on-site CHP natural gas to mirror CHP's CO_2 benefit relative to CARB's electric benchmark. Possible solutions to this critical issue could include the following:

- Payments to CHP owners from Cap-and-Trade Auction proceeds or the Natural Gas Allowance Revenue Fund
- A discount to the carbon price in natural gas to CHP owners and allowances to

CHP owners in Cap-and-Trade. (CCDGCC)

Response: ARB's Cap-and-Trade Program continues to provide an incentive for new CHP that is more GHG-efficient than available alternatives. Not all CHP is more GHG emissions efficient compared to the alternative of purchasing electricity from the grid and using efficient boilers to supply thermal energy needs. This is primarily due to the fact that utilities that provide electricity have large amounts of zero-emission resources. These resources include RPS-eligible renewable resources as well as large hydroelectric facilities and nuclear power plants. It is important that the Cap-and-Trade Regulation be designed to incentivize GHG-efficient production of electricity and thermal output, but the regulation should not encourage new development that is more GHG-intensive that available alternatives.

ARB created the limited exemption for qualified thermal output (section 95852(j)) to provide transition assistance for CHP facilities that would not have faced a compliance obligation "but for" the fact that they used a single system (cogeneration or CHP) to produce both electricity and thermal output. In the 45-Day Modifications to the Regulation, ARB staff proposed this exemption for the first compliance period only. After further discussion with stakeholders, ARB extended the limited exemption through the first three compliance periods. This exemption ensures that facilities that currently have cogeneration systems are not disadvantaged compared to similar facilities that produce their own thermal energy with boilers and purchase electricity from the grid.

The commenter correctly notes that ARB's boiler efficiency assumption used in the limited exemption eligibility formula is 85 percent, but recommends that this benchmark be changed to a less efficient 80 percent. Because ARB's intent is to provide the exemption to relatively efficient existing CHP, staff declines to make this change. An 80-percent boiler efficiency may be typical for existing facilities, but it does not represent efficient production of thermal energy.

The commenter's chart shows that the statewide blended electricity emission rate was 0.256 $MTCO_2e$/MWh in 2011 and is estimated to be 0.168 $MTCO_2e$/MWh in 2020. These emissions rates are the rates that, in the future, CHP electricity production must meet in order to be as GHG-efficient as grid power. The commenter, on the other hand, compares CHP to the emissions rate for the fossil fuel portion of grid electricity. If ARB were to use the commenter's preferred benchmark, ARB would be encouraging development of CHP that is not as GHG-efficient as the alternative.

Staff notes that by using a combination of renewable energy and natural gas-fired CHP, it is possible to create a distributed generation system that is more efficient than the combination of grid electricity and an efficient boiler. In addition, CHP that uses only biogas, or that uses a mix of biogas and natural gas, may also be more efficient than the alternative.

The Cap-and-Trade Regulation creates a level playing field across all sectors of the economy by incorporating GHG costs into both electricity prices and into natural gas prices paid by all end users. The limited exemption for qualified thermal output is necessary to maintain a level playing field for small, medium, and large CHP during the period during which natural gas prices will increasingly incorporate GHG allowance prices. The limited exemption is a form of transition assistance appropriate for existing CHP. In contrast, no transition assistance is justified for new CHP. However, because the Cap-and-Trade Regulation puts a price on GHG emissions, it creates an incentive for new CHP that, in the long term, will be more GHG-efficient than available alternatives.

Because ARB staff believes that the Cap-and-Trade Regulation provides the appropriate incentives to reduce GHG emissions, and provides transition assistance to existing relatively efficient CHP, it is not necessary to adopt the commenter's recommendations to "true-up the effective carbon price adder paid for on-site CHP natural gas to mirror CHP's CO_2 benefit relative to CARB's electric benchmark."

D-1.5. Comment: The discussion draft revisions also purport to address "but for" facilities. The assumptions about the lack of a need for further relief after the first compliance are erroneous, which already is having a chilling effect on CHP investment planning. (CCDGCC)

Response: Section 95852(j) of the regulation was modified in 15-Day Modifications to the Regulation to extend the exemption for "but for" facilities through the second and third compliance periods.

D-1.6. Comment: The CHP "But For" Exemption. ARB staff proposes a limited exemption for CHP during the first compliance period so long as neither the emissions associated with the production of Qualified Thermal Output nor the remaining facility emissions exceed 25,000 MTC02e (new Section 95852(j).) A facility must apply, under penalty of perjury, to ARB for the exemption. CCDC is concerned that the requirement to apply for the exemption under penalty of perjury adds an undue administrative burden, without a corresponding benefit. CCDC suggests that a more efficient approach would be for ARB to notify eligible facilities, which could then provide necessary documentation of emissions levels, without having to go through a formal application process. (CCDGCC)

Response: An application is necessary because not all entities that could qualify for the "but for" exemption may want the exemption. Some entities would need to give up an industrial allowance allocation to qualify for the exemption, and may choose not to do so.

For the first three years of reporting (2008-2010) pursuant to the MRR, "qualified thermal output" had not been defined and was not reported. Therefore, it is necessary for entities that seek the exemption to provide data regarding qualified thermal output for these years. Because the data provided with the application will determine eligibility, ARB staff must ensure that data are accurate, and therefore requires that the applicant attest, under penalty of perjury, that the data are true, accurate, and complete.

Emissions without a Compliance Obligation

D-1.7. Comment: SMUD Supports The Proposed Modifications To The Eligibility Requirements for Biomass-Derived Fuels In Section 95852.1.1 SMUD appreciates the proposed modifications to the provisions in the section describing eligibility requirements for biomass-derived fuels. Fuels that meet the requirements in this sector do not incur a compliance obligation under the Cap-and-Trade Program. SMUD believes that the proposed changes continue to prevent "resource shuffling" with respect to biomass-derived fuels while clarifying that new sources of these fuels, and those sources that were previously delivered to California, do not have compliance obligation. (SMUD 2)

Response: Thank you for the support.

Waste-Energy Emissions

D-1.8. Multiple Comments: We support the changes that the ARB staff has proposed in the regulations that would exclude the three EfW facilities in the state from compliance obligation until the second compliance period. This is consistent with CARB Board Resolutions 11-32 and 12-33. This is also consistent with the Intergovernmental Panel on Climate Change, which recognizes EfW as a source of GHG mitigation.
In the Initial Statement of Reason on page 29 the language states that the facility's internal load appears to be included in the cap and trade. The specific language is below:

> *"In order to obtain the exemption, facilities must report and verify their emissions. In addition, the electricity must be placed on the California grid and not used to meet the facilities internal load."*

However, on page 93 and 94 of the Cap and Trade regulations the limited exemption for EfW facilities does not include any language that would include EfW facilities parasitic load in the Cap and Trade. We would request that the language in the ISOR that includes our parasitic load be removed in order to be consistent with the language on page 93 and 94 and also with Resolution 12-33. (COVANTA 1)

Comment: While the proposed language is consistent with the direction provided in Resolutions 11-32 and 12-33, proposed language in the Initial Statement of Reasons (SOR) contradicts the actual proposed regulatory language. Specifically, we refer you to the following language on page 29 of the ISOR:

"In order to obtain the exemption, facilities must report and verify their emissions. In addition the electricity must be placed on the California grid and not used to meet the facilities internal load."

It is standard business practice for all facilities that generate electricity to utilize a portion of the generated energy to power internal loads, with the net electricity directed to the grid. This language has the unintended consequence of disqualifying the existing waste-to-energy facilities from the exemption proposed in the cap-and-trade language. It is our understanding that this was not the intent of staff. Therefore, to be consistent with the proposed regulatory language we recommend the language be modified as follows:

"In order to obtain the exemption, facilities must report and verify their emissions.-In addition the electricity must be placed on the California grid and not used to meet the facilities internal load."

LACSD appreciates the opportunity to provide comment on the proposed changes to the Cap- and-Trade Regulatory language. Please contact the undersigned at this office with any questions or comments. (LACSD 1)

Comment: The City appreciates the proposed exemption for Waste to Energy facilities from the first compliance period. This is consistent with CARB Board Resolutions 11-32 and 12-33. However, language on page 29 of the ISOR is inconsistent with the aforementioned resolutions, and inconsistent with proposed regulatory changes. This language would prevent a Waste to Energy facility's internal load, and potentially the entire Waste to Energy facility, from inclusion in the first compliance period exemption: *"In order to obtain the exemption, facilities must report and verify their emissions. In addition, the electricity must be placed on the California grid and not used to meet the facilities internal load.* "

While the City uses a small amount of the energy generated at SERRF to power the facility, the majority of electricity is place on the California grid. Given this history, Long Beach requests an amendment to the language on page 29 to ensure consistency with proposed regulatory changes on page 96 of the ISOR. It is our preference that language read:

"In order to obtain the exemption, facilities must report and verify the emissions. In addition the electricity must be placed on the California grid and not be used to meet the facilities internal load. " (LBC)

> **Response:** Thank you for the support. The Cap-and-Trade Program design is intended to send a price signal to incentivize a reduction in CO_2e emissions. If the facility did not produce its own electricity the facility would purchase electricity from the grid. The cost for the electricity purchased from the grid will include the cost to meet the compliance obligation under this Regulation. Providing an exemption from a compliance obligation for the Waste-to-Energy facilities should

not also include an exemption from a compliance obligation for the indirect emissions from the purchase of electricity from the grid. However, after further consideration, ARB staff does not want to require the facility operator to enter the market place to cover the emissions obligation for the emissions due to the parasitic load. ARB staff has recently become aware that it is standard practice for facilities with cogeneration operations to generate electricity to meet its own internal needs, in addition to sending electricity to the grid. ARB staff agrees with Covanta that the regulatory language does not specifically call out whether the emissions exemption includes or excludes the emissions due to parasitic load. ARB staff modified the regulatory language in the 15 day proposal to include parasitic load emissions in the exemption.

D-1.9. Multiple comments: Waste incineration facilities should be covered entities with compliance obligations under the Cap-and- Trade program. (APEN)

Comment: I would like to repeat my earlier request that there be an opportunity for public engagement- particularly from impacted communities and potentially impacted communities- when ARB addresses the question of whether to give an additional exemption from the Cap to municipal solid waste incinerators. The current exemption for incinerators will end in 2015.

We are greatly concerned about how ARB conducted its decision-making process on this issue earlier this year, without notice to the public that the issue would be raised at two board meetings and without an effort to hear from impacted communities. Thus we respectfully urge a public, transparent process for ARB's further decisions on this issue. (GAIA)

Comment: Waste incineration facilities should be covered entities with compliance obligations under the Cap- and-Trade program. (GAIA)

Comment: Secondly, we oppose the exemption for the incinerators. There's no reason to give any special privileges for garbage burning when instead we should be following the State's adopted hierarchy which emphasizes first reducing, reducing, recycling, and composting. (CCA)

Comment: You may be interested in our report on the Clean Development Mechanism and cement kiln incineration in Mexico, available at http://www.no- burn.org/urge-to-stop-approval-of-waste-incineration-in-mexican-cement-kiln. (GAIA)

Response: The proposal is to exempt the emissions from the Waste-to-Energy facilities in California for the first three years of the program, after which the facilities are covered. This study on waste streams by CalRecycle in conjunction with ARB, and resulting plan, have been developed through a multi-agency effort. Please see the CalRecvcle website[80] for more information, and to be able to join the email list for further information. ARB staff will continue to work with

[80] See http://www.calrecycle.ca.gov/Actions/PublicNoticeDetail.aspx?id=1025&aiid=935

stakeholders to address the concerns regarding the combustion of municipal solid waste for a fuel used to generate electricity, and will determine the best approach to municipal solid waste, and the appropriate treatment for these facilities, to meet the intent of AB 32. Currently, MSW Thermal facilities are regulated under the Cap-and-Trade Program. However, ARB staff proposed to temporarily exclude them from the program until 2016 by retiring allowances equal to the reported and verified covered emissions for the facilities, to provide the time necessary to decide the best regulatory framework for these facilities, and for the waste sector as a whole, with respect to the Cap-and-Trade Program.

Comment: My name is Frank Caponi with L.A. County Sanitation District. I'm here today to speak in support of this limited waste-to-energy exemption that's provided as an amendment to the regulations that are before you today. As staff indicated in their presentation, this is consistent with a couple of Board resolution, the most recent of which require that the exemption be provided while the situations debated in the waste sector plan which I spoke of yesterday in my testimony. So we look forward to debating that in 2014. You made hear some come up and say that waste incineration is not appropriate. It's horrible. These are interesting speeches, but not relevant to the item that’s before you today. These will be debated as part of the waste sector plan that will be going down that path in 2014. Thank you. (LACSD 2)

Response: Thank you for the support.

Military Exemption

D-1.10. Comment: On behalf of the Department of Defense (DOD) Regional Environmental Coordinator for EPA Region 9, and the Military Services in California, I am writing in support of your staff's recommendation on amendments to the Cap and Trade Program. Specifically, we support the modification to Section 95852.2(c) to remove the current exemption sunset date for military facilities.

Your staff recognizes that military facilities have mechanisms in place, anchored in federal mandates, which should achieve equivalent reductions through a broad-based approach encompassing sources below applicability thresholds for both the Mandatory Reporting Regulation and Cap and Trade Program. Most important, the proposed amendments will ensure we have the flexibility to meet our national security mission. The military and ARB share many common goals and we look forward to our continued partnership on GHG reductions, renewable energy development and biofuels. We thank your staff for working with us on the issues raised by the Cap and Trade Program and ask your approval of the recommendation. (USDOD)

Response: ARB staff acknowledges the actions the military has taken to reduce GHG emissions. Thank you for the support.

D-1.11. Comment: Emissions without a Compliance Obligation (Section 95852.2)Renewable diesel is not currently exempt from a compliance obligation.

Renewable diesel is one of many types of renewable fuels used to blend with petroleum based fuels to achieve the low carbon intensity required by the Low Carbon Fuel Standard Regulation. Therefore, similar to biodiesel, renewable diesel should be also listed in this section as emissions without a compliance obligation

> **Recommendation:** Amend section 95852.2: Emissions without Compliance Obligation, to include renewable diesel. (WSPA 1)
>
> **Response:** ARB staff appreciates the comment and agrees. ARB staff has included in the proposed 15-day modifications renewable diesel as a fuel that, when combusted, results in emissions without a compliance obligation.

D-1.12. Comment: Language should be re-inserted in § 95852.2 of the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Program, excluding "fugitive and process emissions of CH4 and N2O from municipal WWTPs" from a compliance obligation. This language will prevent any unintended consequences from EPA potentially requiring reporting of these fugitive emissions in its Mandatory Reporting Program. (CWCCG)

> **Response:** The comment is outside of the scope of the proposed amendments. The commenter notes the purpose of the change and additional language could prevent unintended consequences if EPA were to require the reporting of the fugitive emissions in their Mandatory Reporting Program. However, under California's Cap-and-Trade Program, section 95852.2, Emissions Without a Compliance Obligation, exempts emissions from certain source categories and from the combustion of the certain fuel types. The commenter should note the reporting of the fugitive emissions are required for all of the source categories and fuel types listed in this section, and count toward applicable reporting thresholds, as applicable in MRR, but do not count toward a covered entity's compliance obligation.

D-1.13. Comment: Vented and Fugitive Emissions Should not be Classified as "Covered Emissions" to clarify ARB's intent that vented and fugitive emissions from compressor stations and underground storage stations are not to be included in the calculation of an entity's "covered emissions," PG&E recommends the following change: Section 95852.2(b)(4) Vented and fugitive emissions reported under <u>Subarticle 5</u> ~~section 95153~~ of MRR by local distribution companies that report under section 95122 of MRR. (PGE 2)

> **Response:** ARB staff thanks the commenter and has clarified the section to identify the specific sections of relevance in the MRR.

D-1.14. Multiple Comments: <u>Exempting Solar Thermal Facilities Is Consistent With Other Exemptions From The Regulation And Similarly Furthers The State's GHG Reduction Goals Under AB 32 And The RPS Program</u>. While the Legislature and CEC recognize that solar thermal facilities should not be penalized for the use of minimal amounts of nonrenewable fuels, the Regulation does not contain similar protections. Specifically, if the annual GHG emissions at a solar thermal facility, associated with *de minimis* use of nonrenewable fuel, exceed 25,000 metric tons of carbon dioxide equivalents (“CO2e”) annually, the facility will qualify as a covered entity under the Regulation. However, CARB exempted emissions from geothermal power plants from a compliance obligation under the Regulation, notwithstanding the non-anthropogenic GHG emissions associated with this renewable energy source. In doing so, CARB recognized that this method of generation is preferred over fossil fuel-based generation. Like geothermal facilities, solar thermal facilities displace fossil fuel energy production resulting in an overall *decrease* in GHG emissions from power generation. In addition, under the Regulation, GHG emissions from natural gas hydrogen fuel cells are exempt from a compliance obligation. With this exemption, CARB has similarly recognized the importance of furthering this technology in light of its overall GHG emission effects. It would accordingly be appropriate for CARB to provide a similar, but more limited, exemption for certain solar thermal facilities’ emissions from a compliance obligation, consistent with existing statutory and regulatory determinations. Without a limited exemption from the Regulation for such emissions, solar thermal facilities will be forced to incur unrecoverable costs that will substantially burden and possibly jeopardize the successful deployment of this technology, which is important to the State’s ability to reach its goals under AB 32 and the RPS. (CSPA 1)

Comment: The other thing I'd like to speak about is that I'm here also on behalf of the CSP Alliance, which are developers and operators of solar thermal energy facilities. And of course, solar energy displaces greenhouse gas emissions in our electrical sector and is much to be desired. But these solar thermal facilities do use a small amount of gas, a de minimous amount, to help stabilize the energy source to heat up water so it's ready for solar or to keep turbines so they won't crack in the cold at night in the desert. And the Energy Commission prompted by Assembly Member Skinner's Bill AB 1954 has recognized that this diminimous use of gas should be still included in the definition of renewable energy. So we've asked in written comments that the Board consider that as an amendment. You've done so on geothermal. You've done it on fuel cells. We think this is a similar technology that should be recognized in that way. We would ask that, if possible, that the Resolution be amended, if necessary, to include a direction to staff to look at this issue. We have to discussed with staff a couple of different ways this could be accomplished and we would quarterly come further discussions with them. But we do think including it in the Resolution would be very useful. If you have any questions, be happy to answer them. Thank you very much. (CSPA 2)

> **Response:** ARB staff acknowledges the importance of solar thermal technology and fully supports the continued use of these facilities to help California reach its GHG reduction goal. The threshold for entities covered under the Cap-and-Trade Program was set at 25,000 metric tons CO_2e per year. This threshold was carefully selected to capture the emitters that contribute most to California’s GHG emissions and set an economy wide cap. In addition, AB 32 specifically calls out the inclusion of all electricity generated within the state. While more efficient than conventional naturel gas electricity generation, solar thermal has significant GHG

emission from the combustion of fossil fuels. Therefore, any electricity generating facility that exceeds the 25,000 metric ton threshold is a covered entity. At this time, ARB staff declines to make the requested change.

Geothermal emissions were excluded because they occur naturally, are minimal, and are difficult to quantify. Fuel cell emissions were excluded because, in addition to the reduced GHG emissions and small scale of most fuel cells, ARB would like to incentivize technologies that have co-benefits of reducing criteria emissions.

D-2. New Sectors

Compliance Obligation for Natural Gas Suppliers

D-2.1. Comment: Section 95850 describes the general requirement that an entity's compliance obligation results from emissions subject to a compliance obligation. Section 95852.2 then details the types of emissions that do not count towards a compliance entity's compliance obligation. However, ARB's method for calculating a natural gas supplier's compliance obligation does not mention deducting emissions without a compliance obligation. PG&E recommends ARB indicate that "emissions without a compliance obligation" listed under Section 95852.2 will be deducted. PG&E also requests that ARB include a process for notifying natural gas suppliers of entities in their service territories producing "emissions without a compliance obligation" and the corresponding emissions quantities of each entity. This will enable natural gas suppliers to more accurately attribute costs to the appropriate customers.

Accordingly, PG&E recommends the following changes to Section 95852(c):
Suppliers of Natural Gas. A supplier of natural gas covered under sections 95811(c) and 95812(d) has a compliance obligation for every metric ton CO2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California contained in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned, less the fuel that is delivered to covered entities and the fuel delivered to facilities that generate emissions without a compliance obligation as described in Section 95852.2, as follows:

(1) Suppliers of natural gas shall report the total metric tons C0$_2$e of GHG emissions delivered to all end users in California pursuant to section 95122 of MRR;

(2) ARB shall calculate the metric tons C0$_2$e of GHG emissions for natural gas delivered to covered entities and to facilities that generate emissions without a compliance obligation which are customers of the supplier. The emissions will be calculated according to section 95122 of MRR using the reported deliveries (in MMBtu) contained in natural gas supplier in emissions data reports that received a positive or qualified positive emissions data verification statement. Natural gas received data (in MMBtu) contained in covered facility emissions data report that received positive or qualified positive emissions data verification statements will be used to cross check delivery data reported by natural gas suppliers, and will serve as a second source of data in ~~instances of missing supplier data. In~~ the event that a natural gas supplier receives an adverse verification statement. ARB will use the method ~~provisions~~ described in section 9513l(c)(5) of the MRR to calculate the supplier's assigned emission level; or the assigned emissions from natural gas delivered to the covered entity by the supplier of natural gas;

(3) ARB shall provide the supplier of natural gas a listing of all customers and aggregate natural gas (in MMBtu) and emissions calculated from the supplier's natural gas delivered to covered entities;

(4) ARB shall provide the supplier of natural gas a listing of all reporting customers and customer-specific natural gas (in MMBtu) and emissions calculated from the supplier's natural gas delivered to facilities that generate emissions without a compliance obligation and are not covered entities; and

(5) The Executive Officer shall calculate the metric tons $C0_2e$ for which the supplier will be required to hold a compliance obligation based on the supplier's reported emissions less ARB's calculated emissions from deliveries to covered entities and to facilities that generate emissions without a compliance obligation, which are customers of the supplier. The Executive Officer shall provide this value to the supplier of natural gas within 30 days of the verification deadline in section 95103 of MRR. (PGE 2)

Response: ARB does not agree additional language needs to be included to further detail the direction ARB will take to notice the natural gas suppliers. The existing regulatory language already contains language to describe the information ARB will provide to the natural gas suppliers.

D-2.2. Comment: ARB's proposed approach for calculating the compliance obligation of liquefied natural gas (LNG) suppliers, under Section 95852(1) does not include adjustments for LNG deliveries to other covered entities (e.g., natural gas suppliers). As a result, some LNG (e.g., LNG purchased by natural gas suppliers that is injected into the natural gas pipeline and accounted for in natural gas suppliers' GHG reporting) could be double-counted for compliance purposes. (PGE 2)

> **Recommendation:** PG&E recommends the following amendments to Section 95852(1) to ensure that GHG emissions obligations associated with LNG deliveries to other covered entities are not double counted:
>
> (1) Suppliers of Liquefied Natural Gas. A supplier of liquefied natural gas covered under <u>sections 958ll(g) or 95812(d) has a compliance obligation for every metric ton</u> $\underline{C0_2e}$ of <u>GHG emissions included in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned that would result from full combustion or oxidation of the quantities on liquefied natural gas or compressed natural gas imported into California, except for products for which a final destination outside California can be demonstrated or products delivered to other covered entities as calculated by the Executive Officer.</u>
>
> **Response:** ARB staff does not agree that modifications need to be made to this section. Sufficient language is already in place in this regulation and in MRR to prevent double counting of emissions.

E. ELECTRICITY

E-1. Voluntary Renewable Energy (VRE)

E-1.1. Comment: We request additional clarification on the change to Sec. 95841.1(a). Please clarify whether this change will affect the vintage of RECs retired per this section, and how you anticipate this will affect program administration. There are at least two ways that the rules of other programs may make this requirement difficult to enforce and/or disruptive to the voluntary renewable energy market. First, WREGIS rules on certificate issuance would, for example, issue RECs for December 2014 generation in early 2015, meaning that if those December 2014 RECs were being used toward 2014 sales and VRE retirement was requested in 2014 for those sales, the applicant could not retire such RECs in 2014. Second, many voluntary renewable energy sellers procure supply and make REC retirements early in the year after the year for which they might request VRE retirements; for example, a voluntary renewable energy seller might purchase RECs in early 2016 in order to cover sales made in 2015, and if they then requested VRE retirement for their 2015 sales, they would only be able to retire the purchased RECs in 2016. If ARB wants to year match, the date of retirement is not critical; rather the year of generation in relation to the year to which VRE retirement is applied is important. (CRS 1)

> **Response:** ARB staff appreciates the commenter for pointing out the timing for REC issuance and ARB staff has made changes in the 15-day amendments to clarify this issue. For clarification, if electricity is generated in late 2014, and the REC is not issued until early 2015, then the REC will not be able to be retired until early 2015. ARB staff will accept a REC that is issued in early 2015, as long as it represents electricity generated in 2014.

E-1.2. Comment: However, the Cap-and-Trade regulations currently reserve use of the VRE program for only directly delivered renewables, not covering the “RPS adjustment” pathway. SMUD continues to recommend that the Cap-and-Trade regulations allow use of the VRE provisions for renewable procurement that could take advantage of the RPS Adjustment if the procurement is associated with an entity’s RPS obligation, rather than part of a VRE procurement. This will provide equal treatment for RPS procurement and VRE procurement.

Note that SMUD is not recommending application of the VRE to renewables that are not eligible for the RPS – SMUD agrees with the ARB policy of reserving the VRE adjustment for only those renewables that are RPS-eligible. Rather, SMUD is requesting greater equivalency between the VRE provisions and the RPS, allowing both directly delivered and RPS adjustment provisions in the VRE context to lead to GHG reductions through allowance retirement from the VRE, just as both of these pathways are accepted in the RPS. (SMUD 2)

> **Response:** ARB staff declines to make the modifications suggested by the commenter. Staff does not agree the allowance retirement under VRE should include the procurement of electricity that is not able to be directly delivered to

California. If modifications to the Regulation were made would result in additional allowance retirement for the procurement of renewable electricity generation located outside of California. ARB acknowledges some generators, although located outside of the state, result in the electricity delivered to California, which directly sinks in California. The Regulation include provisions for these generators with the ability to directly deliver electricity to California through allowance retirement under VRE, and through the provisions to report the emissions from these generators as zero emissions.

E-1.3. Comment: The following changes would allow resources that would normally count for the state's RPS to also be fully viable for voluntary program procurement by a covered Cap-and-Trade entity, without incurring a compliance obligation or challenging the GHG benefits expected from voluntary renewable procurement.

95841.1(a) Program Requirements: The end-user, or VRE participant acting on behalf of the end-user, must meet the requirements of this section. Generation must be new and not have served load prior to July 1, 2005. Allowance retirement for purposes of voluntary renewable electricity will begin in 2014 for 2013 generation. Voluntary renewable electricity must be directly delivered to California or associated with a transaction that uses the RPS adjustment. RECs, if created, must be retired within the year for which VRE retirements are requested.

95852(b)(4)(B) The RECs associated with the electricity claimed for the RPS adjustment must be placed in a ~~the~~ retirement subaccount of the entity party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25 and either designated as retired for the purpose of compliance with the California RPS program; or designated as retired for purposes of a voluntary green pricing program operated by a covered entity ~~used to comply with California RPS requirements~~ during the same year ~~in~~ for which the RPS adjustment is claimed. (SMUD 2)

Response: ARB declines to make the suggested modifications. The purpose of the RPS adjustment is to acknowledge the utility's high cost of meeting RPS. ARB does not agree with the commenter that the RPS adjustment should be extended to allow for an adjustment to a compliance obligation for electricity that was procured to meet a utility's voluntary green pricing program.

E-2. Imported Electricity

Reporting REC Serial Numbers for Electricity Reported as Delivered From a Specified Source

E-2.1. Multiple Comments: Section 95852(b)(3)(D) of the Regulation has been revised to require REC serial numbers to be reported instead of requiring the RECs to be retired in order to claim renewable specified source imports. SCPPA commends the ARB on this change. Reporting REC serial numbers avoids the problem of double-counting

RECs without restricting a covered entity's flexibility as to when to retire the REC under the Renewable Portfolio Standard ("RPS"). (SCPPA 1)

Comment: Regarding the change to the criterion for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emissions factor at Sec. 95852(b)(3)(D), from "RECs must be retired" to "REC serial numbers must be reported," this change appears to be appropriate provided that 1) the importer is not itself delivering to load, and … (CRS 1)

Response: Thank you for the support.

E-2.2. Multiple Comments: In a clarification regarding importation of electricity with associated RECs, new language requires the reporting of associated serial numbers, and repeals the prior requirement to retire associated RECs. This makes sense when an entity is attempting to claim an RPS Adjustment, and is an improvement over the prior requirement for same-year retirement. Indeed, we suspect that the intent of the change is to clarify the RPS Adjustment requirements, and we support this goal.
The problem comes, however, when power is imported by an entity that is not eligible for or intending to claim an associated RPS adjustment. First, that entity may not own the associated RECs; indeed, it may not even be aware that associated RECs have been created. In such situations, it has no contractual right to obtain REC serial numbers, even if aware of their existence. Furthermore, the associated RECs may not necessarily be sold to an entity that intends to use them to satisfy a California requirement. For this reason, it is neither logical nor appropriate to require any and all importers to report associated REC serial numbers. Therefore, we strongly recommend adjusting the language in the proposed amendment to make clear that the requirement to report a REC serial number only applies to an entity that applies for an RPS adjustment for the associated imported power. (MS)

Comment: WPTF appreciates the modification to section 95852(b)(3)(D) to require reporting of the serial numbers of associated Renewable Energy Credits (RECS) in conjunction with direct delivery of renewable energy instead of retirement of those REC. We understand from guidance issued in relation to the Mandatory Reporting Regulation in February of this year[81] as well as revised definition of renewable energy credit (311), the term REC when used in this regulation refers only to renewable energy credits generated from eligible renewable resources under the California RPS program. Thus, in the case that when electricity is delivered from a resource that is eligible under in other state renewable energy programs or in the voluntary market but that is not a California RPS eligible renewable resource, it is not necessary for the importer of that electricity to report the associated RECS in order to claim the specified emission factor for that resource. WPTF supports this approach, but requests that staff confirm whether our interpretation is correct. (WPTF 1)

Comment: Requirements for Direct Delivery of Renewable Electricity.
PGE appreciates the proposed modifications to both the Mandatory Reporting

[81] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/specified_source_guidance.pdf

Regulation and the Cap and Trade Regulation to require reporting of the serial numbers of associated Renewable Energy Credits (RECs) in conjunction with direct delivery of renewable energy instead of retirement of those RECs. PGE requests that staff confirm that when electricity is delivered from a resource that is eligible in other state renewable energy programs or in the voluntary market but is not a California RPS-eligible renewable resource, it is not necessary for the importer of that electricity to report the associated RECs in order to claim the specified emission factor for that resource. (PGEC)

Comment: Regarding the change to the criterion for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emissions factor at Sec. 95852(b)(3)(D), from "RECs must be retired" to "REC serial numbers must be reported," this change appears to be appropriate provided that 1) the importer is not itself delivering to load, and … (CRS 1)

> **Response:** Thank you for the support. In response to the request that reporting of REC serial numbers only apply to an entity that reports electricity eligible for an RPS adjustment the regulatory requirement has been clarified to require the reporting of a REC serial number, if the REC was created, and the requirement for REC retirement has been removed, for electricity that meets the Cap-and-Trade and MRR requirements for claims to a specified source. For claims to a specified source, direct delivery requirements, pursuant to MRR, will have been met and either the importer or the utility will have a direct relationship to the facility, and will have access to the REC serial numbers. Otherwise, the importer will need to modify contracts to include obtaining the REC serial numbers.
>
> The purpose of the modified provision is to allow for public monitoring for double counting of the zero emissions, while not requiring the REC to be retired. Reporting the REC serial number under MRR allows for the access to information that the underlying electricity for that REC was reported as zero emissions, under California's MRR. ARB staff will post the REC serial numbers on its website so that others can determine whether a REC they are considering purchasing contains all of the attributes they intend.
>
> On the request to make a clarification as to whether REC serial numbers only need to be reported if the facility is California RPS eligible, the Cap-and-Trade Regulation requires if RECs are created the serial numbers must be reported to MRR. The Cap-and-Trade Regulation does not differentiate whether the resource is RPS eligible or not.

REC Retirement and Double Counting Emissions

E-2.3. Multiple Comments: 2) the REC stays in state and the electricity is not wheeled out of state as zero emissions electricity. If the importer is delivering directly to end users, including for the RPS, then retirement of the REC should be required to prevent double counting. If the REC is traded out of state to be used in a different system by either the importer, an in-state LSE, or other entity after the REC has been reported by the importer to avoid a compliance obligation, then there is double counting. Only in the case that the importer is not delivering to load and simply using the REC to prove that the electricity was delivered into the state without emissions (avoiding compliance obligations) and when the REC is exclusively traded and used in state is "reporting" sufficient. The in-state LSE isn't regulated for imports, so there wouldn't be double counting of the REC under the cap-and-trade in this case. For our comments on the RPS adjustment section of the regulation (Sec. 95852(b)(4)), see our comments further below.

- Please clarify how double counting will be avoided if the REC is sold out of state or power is wheeled out of state as zero emissions after "reporting" by the importer per Sec. 95852(b)(3)(D). How will ARB track the REC to make sure it stays in state and, in the case that the power is wheeled out of state, how will ARB prevent double counting?
- We suggest that the language of the Sec. 95852(b)(3)(D) be amended further to include the underlined text: "If RECs were created for the electricity generated and reported pursuant to MRR, then the REC serial numbers must be reported and verified pursuant to MRR <u>and shown to be</u> <u>used in California.</u>"
- Please also clarify when this reporting will occur, and when the serial numbers will be posted publically. We suggest that public posting of serial numbers occur (or that these serial numbers be otherwise made publically available) in as close to real time as possible. If there is a time lag, there may be several other parties that transact the REC before it is made known that it only has GHG value if used within California. (CRS 1)

Comment: REMA's comments specifically address Sec. 95852(b)(3)(D) of the September 2013 regulatory draft and its potential implications of double counting RECs. As ARB is aware, once RECs are double counted, they are meaningless for compliance with federal mandates, corporate sustainability goals, or for sale to willing buyers (of which there are many). Revising the Sec. 95852(b)(3)(D) to prevent double counting necessitates that ARB consider the following three pillars:

i. ARB should not allow null power imports to claim a specified emissions rate of zero emissions. The REC must travel with the specified electricity when imported. To allow otherwise is to allow double counting of environmental attributes.

ii. If the electricity importer is an RPS-obligated load serving entity (LSE), then REC retirement must be demonstrated.

iii. If the electricity importer is not an RPS-obligated LSE, then reporting of the REC is satisfactory so long as a subsequent party in the contract chain does not sell the REC to an out-of-state RPS or sell the power out-of-state as zero emissions. This would require, essentially, that the benefit stays within the state of California.

We encourage the ARB staff to consider the recommendations above and incorporate them into the state's strategies to promote GHG reductions, increase renewable energy, and avoid double counting. Doing so will ensure that out-of-state RECs are properly reported to prevent double counting and healthy compliance and voluntary REC markets (in and outside California) are maintained. REMA would like to thank the ARB again for allowing us to play a substantive role in its rulemaking process and hope to work closely together as this issue further develops. (REMA)

Response: The purpose of the modified provision is to allow for public monitoring for double counting of the zero emissions, while not requiring the REC to be retired. Reporting the REC serial number under MRR allows for the access to information that the underlying electricity for that REC was reported as zero emissions, under California's MRR. ARB staff will post the REC serial numbers on its website so that others can determine whether a REC they are considering purchasing contains all of the attributes they intend. ARB staff acknowledges the issue surrounding the timing of the posting of the serial numbers. The reporting deadline for electricity importers is specified in MRR as June 1. Serial numbers will be posted after verification as close to real time as possible to minimize any time lag.

One commenter suggests ARB staff include an additional requirement to prevent the re-sale of a REC, once the underlying electricity has been imported to California, and reported by the importer as coming from a zero emission specified source facility. ARB staff does not have jurisdiction over actions that entities take with the RECs. As such, ARB staff does not agree this modification is needed.

RPS Adjustment REC Retirement Requirements

E-2.4. Multiple Comments: We support changes to Sec. 95852(b)(4). We strongly encourage ARB to adopt changes to Sec. 95825(b)(4)(B) as proposed, and not to remove the requirement for REC retirement included in the proposed changes in favor of "reporting of REC serial numbers." Compliance with the CEC's requirements for RPS verification, including REC retirement, is the only way to prove that electricity claimed for the RPS adjustment was used for the RPS. If ARB were to change this section to remove the requirement for retirement in favor of reporting, as has been recommended by several commenters during this comment period, ARB would still need to check with the CEC to ensure retirement, but in this case there would be a significant time differential between reporting for ARB and verification by the CEC. There could in fact be multiple years between the year of RPS adjustment claim and the CEC's verification, and if it was found by the CEC that there was no retirement, it would be several years after the RPS adjustment claim was made. For these reasons, we again strongly recommend that the proposed changes to Sec. 95825(b)(4)(B) be adopted, including the requirement for REC retirement pursuant to PUC 399.25 (CRS 1)

Comment: Concerns over double counting could be additionally alleviated by ARB's adoption of Sec. 95825(b)(4)(b) as proposed. REC retirements for RPS verification would allow the California Energy Commission (CEC) to prove that electricity claimed for the RPS adjustment was indeed used for the RPS. Moving from REC retirement to “reporting” could instigate delays in reporting between ARB and the CEC, thus unnecessarily complicating the process and risking environmental claims.

On these issues, REMA supports the comments of the Center for Resource Solutions (CRS), as its guidance on double counting represents broadly accepted practices for the voluntary market; its recommendations and analyses are the norm and are reflected in federal programs, regional energy registries, and building performance standards. We encourage the ARB staff to consider the recommendations above and incorporate them into the state’s strategies to promote GHG reductions, increase renewable energy, and avoid double counting. Doing so will ensure that out-of-state RECs are properly reported to prevent double counting and healthy compliance and voluntary REC markets (in and outside California) are maintained. REMA would like to thank the ARB again for allowing us to play a substantive role in its rulemaking process and hope to work closely together as this issue further develops. (REMA)

Comment: We support changes to Sec. 95852(b)(4) (CRS 1)

> **Response:** Thank you for the support. ARB staff acknowledges the importance of requiring REC retirement due to the program allowances under RPS, which allow RECs to be transferred or sold up to 36 months before they must be retired to meet compliance requirements under RPS. If ARB staff did not require the REC to be retired, or allowed for a delay in retirement, it could result in a covered entity receiving an adjustment to a compliance obligation due to a California Utility’s RPS requirements, when the adjustment was not warranted, because the utility sold or traded the REC. This could occur when a California utility realizes it is already on target to meet the RPS goals, and then sells the REC to another out-of-state utility to meet the RPS goals of that other state, after the California utility’s compliance obligation was either directly or indirectly adjusted, due to the RPS adjustment.

E-2.5. Multiple Comments: At the ARB’s July 18th Workshop, SCE again raised the issue of REC retirement for the RPS adjustment because the proposed regulation language remained unclear. SCE was pleased that the ARB clarified that the regulations allow the RPS adjustment for out-of-state renewable energy that is not imported into California, as long as the corresponding RECs are deposited in the Western Renewable Energy Generation Information System (“WREGIS”) “retirement sub- account” in the year they were generated, even though the actual retirement of such RECs for RPS compliance purposes may occur later (within the RPS compliance window set by the California Energy Commission). This is an important clarification because the ARB’s language previously suggested that in order to claim the RPS adjustment, the retirement for compliance with the RPS program must also occur during the same year in which the RECs were created. SCE greatly appreciates this clarity and urges the ARB to make changes in its final regulations reflecting the clarification provided by Staff. Specifically, SCE suggests the following change to Section 95852(b)(4)(B) of the cap-and-trade regulation:

The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.13 and designated as retired for the purpose of compliance with the California RPS program used to comply with the California RPS requirements during the same year in for which the RPS adjustment is claimed (and during the year in which those RECs were created). The RECs must be designated as retired for the purpose of compliance with the California RPS program on a schedule consistent with the rules governing that program. (SCE 1)

Comment: WPTF remains concerned that the provisions related to the RPS adjustment are not consistent with RPS program requirements. We have three concerns. First, while we appreciate CARBs attempt to address RPS program inconsistency through the modification of Section 95852(b)(4)(B) to allow RECs to be retired during the same year for which the RPS adjustment is claimed, this is still problematic for many importers. As proposed, it would force an importer of firming and shaping electricity to carry a carbon obligation until such a time as the REC is retired in accordance with RPS program rules.[82] To avoid carrying this carbon obligation, the RPS obligated entity would be forced to retire the REC early. This inconsistency is discriminatory and eliminates the flexibility provided under California statute to support short---term REC procurement contracts to meet RPS compliance targets. Under RPS program rules, once retired, RECs acquired pursuant to short---term RPS contracts cannot be carried over for future compliance.

Rather than require retirement of associated RECS, the regulation should instead require that the RECs have been appropriately matched to the imported substitute power. The RPS program requires that, for both portfolio content category one and category two, RECs generated by the eligible renewable resource must be matched to specific NERC e---tags to demonstrate either direct delivery in the former case, or delivery of substitute power in the latter.2 The Western Renewable Energy Generation Information System (WREGIS) provides a function that allows users to match specific RECs to specific NERC e---tags for scheduling of power. This matching can only be done by the entity with title to the REC as it is imported into California, and cannot be changed. LSEs must then provide this information in the form a “WREGIS NERC e---tag Summary Report” to the California Public Utilities Commission or the California Energy Commission to demonstrate that delivery requirements for procurement categories one and two have been met. This same report can be used by CARB to ensure that claims to renewable energy and the RPS adjustment are valid. If staff remains concerned about the unlikely possibility that RECs associated with the RPS adjustment will be resold, we would suggest that CARB also require that the procuring RPS---obligated entity to submit an attestation that the associated RECs will be used for category 2 RPS compliance.

Second, the language of the main paragraph of 95852(b)(4) assumes that the entity claiming the RPS adjustment will either be importing or procuring renewable energy.

[82] The RPS program requires RECs be retired within 36 months of generation.

The first case will never occur, as that would be considered a direct delivery of renewable energy and ineligible for the RPS adjustment. The second case would occur if the importer is the entity subject to the RPS. However, in many cases the entity that needs to claim the RPS Adjustment will only be importing substitute power on behalf of an entity subject to the RPS. Under RPS program rules, the importing entity is not required to have any contract to procure the renewable electricity or associated RECs. In addition, there are instances where the importing entity has a "Corporate Association" with the RPS obligated entity, but there is no contract in place for the transfer of power. Finally, the current language is not sufficiently clear with respect to whether the various references to 'electricity' refer to the imported substitute electricity (i.e. the firming and shaping power) for which the RPS adjustment is needed, or to the electricity generated by the eligible renewable resource. Because of this ambiguity, the language suggests that the contract for substitute electricity must be the same contract as the contract for procurement of the RECs. This is not the case – RPS program rules only require that the contract for substitute electricity be entered into no earlier than the time the renewable electricity is purchased and prior to the initial date of generation of the renewable electricity. We believe the intent of and requirements for claiming the RPS adjustment would be clearer if the regulation were to explicitly and correctly characterize the link between the importation of 'substitute energy' in association with renewable electricity that is procured by an entity subject to the RPS, but is not directly delivered.

Recommendation: WPTF recommends the addition of a new definition of the RPS adjustment, and modifications to section 95852(b)(4) to address these concerns:

(NEW) "RPS Adjustment" means a deduction from the compliance obligation of an electricity importer that is an entity subject to the RPS or its designated counter-party, associated with the procurement pursuant to California Public Utilities Code 399.16 (b)(2) by the entity subject to the RPS program of electricity that is generated by an eligible renewable resource, but not directly delivered to California.

(4) RPS adjustment. Delivery of e~~E~~lectricity associated with the procurement by an entity subject to the RPS of electricity ~~imported or procured by an electricity importer~~ from an eligible renewable energy resource reported pursuant to MRR must meet the following conditions to be included in the calculation of the RPS adjustment:

(A) The electricity importer must ~~have~~ either:

1. Be an entity subject to the California RPS with o~~O~~wnership or contract rights to ~~procure the electricity and~~ the RECs associated with the electricity generated by the eligible renewable energy resource, or have a corporate association with that entity, as verified pursuant to the MRR;

2. Have a contract to import ~~procure~~ electricity on behalf of ~~and the associated RECs on behalf of~~ an California entity subject to the California RPS that has ownership or contract rights to the ~~electricity and associated~~ RECs associated with the electricity generated by the eligible renewable energy resource, as verified pursuant to MRR.

(B) Within 36 months of creation, t~~T~~he RECs associated with the electricity generated by the eligible renewable resource and claimed for the RPS adjustment must be placed in the retirement subaccount of the entity subject to the RPS ~~party to the contract~~ in 95852(b)(4)(A) or (B), in the accounting system established by the CEC pursuant to PUC 399.13 and designated as retired for the purpose of compliance with the California RPS program ~~during the same year in for which the RPS adjustment is claimed~~. RECs claimed for the RPS Adjustment must not be resold by the entity subject to the RPS, or used for a purpose other than that entity's compliance with the RPS.

(B bis) The electricity importer must be able to provide evidence that the electricity delivered was matched with the eligible renewable resource.

(C) The quantity of emissions included in the RPS adjustment is calculated as the product of the default emission factor for unspecified sources, pursuant to MRR, and the quantity (MWh) of ~~reported~~ electricity generated by the eligible renewable resource ~~(MWh)~~ and procured by the entity subject to the RPS. ~~that meets the requirements of this section, 95852(b)(4).~~

(D) No RPS adjustment may be claimed for an eligible renewable energy resource when its electricity is directly delivered. (WPTF 1)

Comment: The current regulatory provisions do not permit use of the RPS adjustment by importers of substitute electricity that do not have ownership or contractual rights to the associated RECs. From conversations with staff, it appears that this is intentional based on staff expectation that retail providers will compensate importers of substitute energy for the carbon costs of that electricity, and that the retail providers will be able to recoup this additional cost by taking the RPS adjustment. While we agree with the intent of this approach – that the benefit of the RPS adjustment accrues to the retail provider, we note that it will not work for many existing contracts and for many retail providers. First, there are existing RPS contracts in place under which the retail provider's counter-party does not take title to the associated RECS, but is responsible for importing firming and shaping electricity and the counter-party is expected to use the RPS adjustment to cover the carbon cost (rather than the retail provider paying for the importer's carbon cost). These contracts would have to be re--□negotiated if the importer is not able to take the RPS adjustment.

Second, we note that many small retail providers do not have a compliance obligation under the cap and trade program because they do not own in--□state generation and are not first jurisdictional deliverers of electricity. Under the current regulation, these retail providers would not be able to take the RPS adjustment since they would have no emission obligation against which to apply the RPS adjustment. Yet these retail providers are subject to the RPS and will incur increased costs due to the carbon price embedded in their electricity purchases.

In order to address this problem, it is critical for CARB to provide a mechanism to enable importers of firming and shaping power pursuant to a retail provider's RPS procurement to claim the RPS adjustment. We therefore propose that staff modify the regulation to allow the RPS adjustment to be taken either by the retail provider, or another entity designated by that retail provider to use the RPS adjustment on its behalf.

Attestation and reporting and verification of REC retirement: In our previous comments, WPTF proposed that, instead of requiring that RECs associated with the RPS adjustment be retired in order for the RPS adjustment to be used, the regulation should require an attestation from the retail provider that the RECs reported in association with the RPS adjustment would be retired for that entity's RPS compliance. To facilitate staff consideration of this proposal, we provide additional recommendation on the language for such an attestation, as well as how the retirement of associated RECs could be reported and verified.

- As part of its annual report, each retail provider wishing to use the RPS adjustment would be required to submit an attestation that states: "I certify under penalty of perjury that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity] and that [name of entity] shall retire all RECs reported herein in association with the RPS adjustment for RPS compliance within 36 months of generation."
- Each retail provider would have the option to designate other entities (i.e. importers of incremental power on the retail provider's behalf) that may use the RPS adjustment on behalf of that retail provider. In order to use this option, the retail provider must identify the other entity, the other entity's designated quantity of RPS Adjustment and the RPS project ID of the resource from which the renewable energy was procured.
- CARB staff would provide verifiers with a list of entities authorized by retail providers to use the RPS adjustment, and the associated RPS project IDs
- Other entities that are authorized by retail providers to use the RPS adjustment on the retail provider's behalf must enter the RPS project ID on the NERC tag for the delivered electricity, consistent with RPS program rules.
- CARB should develop a template for reporting by retail providers of the serial numbers and vintages of RECs reported in association with the RPS Adjustment, including those for which another entity has been authorized to use the RPS adjustment. (We note that the MRR already requires reporting of REC serial numbers, but no template has been provided.) Reporting of the vintage of RECs would enable CARB staff and verifiers to determine the deadline for retirement in accordance with RPS program rules. For example, a February 2012 vintage REC must be retired by February 2015.

- In its annual report, each retail provider must include information on RECs claimed for the RPS adjustment for the previous reporting year, and provide an update on the status (retired or non---retired) of previously reported RECs that were not retired at the time the RPS adjustment was claimed.
- As part of the verification of retail providers annual reports under the MRR, verifiers would spot---check reported REC retirement. Retail providers can document REC retirement by providing the verifier with a copy of their WREGIS retirement account holdings.
- In the case that another entity has been authorized by a retail provider to use the RPS adjustment, verifiers would check that the entity can document that NERC tags contain the appropriate RPS project ID. (WPTF 2)

Comment: Noble Americas Energy Solutions LLC ("Noble Solutions") has previously commented on Section 95852(b)(4) of the Cap-and-Trade regulation dealing with the RPS Adjustment.[83] The "same year rule" expressed in Section 95852(b)(4)(B) deprives Noble Solutions and others similarly situated of the benefit of a key feature of the RPS law. Under the terms of Public Utilities Code Section 399.21(a)(6), Renewable Energy Certificates ("RECs") have a three-year "shelf life" before they must be retired to demonstrate compliance with the RPS program.[84] This provides retail sellers with a measure of flexibility in building an RPS portfolio that satisfies the complex "Content Category" requirements[85] of the RPS law.
The RPS Adjustment is a mechanism that recognizes that an electricity import associated with "substitute energy" (Category 2) RPS contract[86] should not bear a carbon liability. The documentation supporting a Category 2 transaction links each MWh of the import schedule with a MWh of generation from an eligible renewable resource. This documentation is aggregated and submitted to the California Public Utilities Commission and the California Energy Commission as the "WREGIS-NERC e-Tag Summary Report" in connection with an entity's RPS compliance showing. This Report permanently links each REC with its corresponding hourly import schedule.

The "WREGIS-NERC e-Tag Summary Report" represents an ironclad audit trail that insures that each Category 2 REC procured is matched with an E-Tag for California RPS reporting purposes. The Category 2 RECs can be used in any compliance period, so long as the three-year term is observed. Although the RECs are not required to be retired in the same year as a Category 2 transaction occurs, the substitute energy must be scheduled in the same calendar year as the generation from the RPS-eligible facility.[87] But the "same year rule" expressed in Section 95852(b)(4) of the Cap-and-

[83] See Comments of Noble America Energy Solutions LLC, submitted to the CARB website on August 2, 2013, and incorporated herein by reference.
[84] PU Code §699.21(a)(6) reads as follows: "A renewable energy credit shall not be eligible for compliance with a renewables portfolio standard procurement requirement unless it is retired in the tracking system established pursuant to subdivision (c) of Section 399.25 by the retail seller or local publicly owned electric utility within 36 months from the initial date of generation of the associated electricity."
[85] See PU Code §699.16(c)
[86] See PU Code §699.16(b)(2).
[87] See D. 11-12-052, Ordering Paragraph 2: "A retail seller claiming that procurement for compliance with the California renewables portfolio standard from a contract or ownership agreement signed, or utility-owned generation in commercial operation, on or after June 1, 2010 counts in the portfolio content category described in new Pub. Util. Code §

Trade regulation unfairly imposes a carbon liability on Category 2 RECs that are not retired in the same year the transaction occurs. The "same calendar year" scheduling requirement specified in D. 11-12-052 should satisfy the policy objectives expressed in the "same year rule" of Section 95852(b)(4), but without the unnecessary requirement to retire the RECs in that same year. There is a straightforward fix Section 95852(b)(4). The "WREGIS- NERC e-Tag Summary Report" should provide CARB staff with adequate evidence that the RPS Adjustment RECs have been matched to a schedule in the same calendar year that the RECs were created.

Noble Solutions proposes that Section 95852(b)(4)(B) be amended to remove the "same year" rule, to acknowledge the three-year shelf life of RECs guaranteed by the RPS statute, and to explicitly prohibit the use of RECs claimed for the RPS adjustment for any use other than compliance with the RPS program by the party that claims the RPS adjustment.[88] In its August 2, 2013 comments, Noble Solutions proposed amendments to Section 95852(b)(4)(B) that incorporated each of these elements. The Western Power Trading Forum ("WPTF") has produced proposed amendments to the RPS Adjustment language that Noble Solutions supports. CARB should adopt amendments to the RPS Adjustment language that harmonizes the Cap-and-Trade regulation with state law governing RPS compliance. Noble Solutions appreciates the opportunity to comment on the proposed Cap-and-Trade amendments, and urges CARB to change Section 95852(b)(4)(B) as proposed herein. (NOBLE 1)

Comment: SCPPA's preferred position continues to be that the ARB should not require RECs to be retired to claim the RPS Adjustment. REC retirement is a crucial part of the RPS program administered by the California Energy Commission. To avoid interfering with that program and to avoid making it more difficult for utilities to meet its challenging goals, no other agencies should require RECs to be retired. The ARB should adopt the same approach to RPS Adjustment RECs as it proposes for specified source RECs: reporting rather than retirement.

However, if this solution cannot be adopted, minor additional changes to sections 95852(b)(4)(A) and (B) should be made to allow for the full variety of transactions that currently take place in relation to electricity eligible to be counted towards the RPS Adjustment. For example, the importer of the electricity substituting for the renewable energy may or may not be the entity that holds title to the RECs and may or may not be the entity that is subject to the RPS program.

> **Recommendation:** SCPPA's proposed changes to sections 95852(b)(4)(A) and (B) (accepting the changes proposed in the September 4, 2013, amendments) are set out below:

399.16(b)(2), must provide information to the Director of Energy Division sufficient to demonstrate that the generation from that facility is firmed and shaped with substitute electricity scheduled into a California balancing authority ***within the same calendar year*** as the generation from the facility eligible for the California renewables portfolio standard…" [***emphasis*** added}

[88] CARB could also require an attestation to the effect that RECs claimed for the RPS Adjustment will not to be sold or used for compliance in any other jurisdiction.

RPS adjustment. Electricity procured by an electricity importer from an eligible renewable energy resource reported pursuant to MRR must meet the following conditions to be included in the calculation of the RPS adjustment:
(A) The electricity importer that imports electricity in substitution for the electricity from the eligible renewable energy resource must have:

1. Ownership or contract rights to procure the electricity or substituted electricity and the associated RECs generated by the eligible renewable energy resource; or;

2. A contract to importprocure electricity and the associated RECs on behalf of an entity subject to the California RPS that has ownership or contract rights to the electricity or substituted electricity and associated RECs generated by the eligible renewable energy resource, as verified pursuant to MRR

(B) The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity subject to the California RPS party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.13 and designated as retired for the purpose of compliance with the California RPS program during the same year for which the RPS adjustment is claimed. (SCPPA 1)

Comment: PG&E suggests ARB clarity the intent of revisions to Section 95852(b)(4)(A) concerning the Renewable Portfolio Standard (RPS) Adjustment. Specifically, the RPS adjustment is available to electricity importers to reduce overall compliance obligation for RPS-eligible electricity generated outside of California that is not directly delivered to the state. The draft Regulation should clarify that an electricity importer is not restricted from re-selling the underlying electricity associated with the eligible renewable energy resource. Section 95852(b)(4)(A) should be amended as follows:

The electricity importer must have either: I. Ownership or contract rights to procure the electricity and the associated RECs generated by the eligible renewable energy resource provided that the electricity importer may resell the underlying electricity generated by the eligible renewable energy resource; or... (PGE 2)

Comment: The Regulation Should be Revised to Strike the Retirement Requirement Associated with the RPS Adjustment. The RPS Adjustment is a necessary element to the Regulation, and M-S-R appreciates its inclusion therein. However, in order to keep from disadvantaging entities subject to compliance obligations under both the State's GHG reduction and RPS programs, it is necessary for the Regulation to accurately reflect the RPS mandates imposed on load serving entities. Accordingly, M-S-R encourages the Board to direct staff to draft 15-day revisions to the Proposed Amendments clarifying section 95852(b)(4)(B) of the Regulation. Specifically, the Regulation should not place constraints on the ability of covered entities subject to the States' RPS laws to retire a renewable energy credit (REC) in order to utilize the RPS Adjustment.

The RPS mandate imposes significant renewable procurement obligations on the State's electrical distribution utilities, including restrictions on the type of renewable resources that can be procured and the timing for retiring RECs, all of which contribute the achieving the overall objectives defined in AB 32. The Regulation must take those constraints into account, and recognize the important impact that the RPS program has on covered entities that are also electric utilities required to comply with the RPS. In the 2011 FSOR[89], Staff noted that the "RPS adjustment provision accomplishes the purpose of reducing a deliverer's compliance obligation by accounting for renewable imports that staff previously addressed through the 'replacement electricity' requirements."[7] However, the proposed revision, while intending to clarify the original intent, fails to do so. Indeed, while the ISOR states that the proposed revision "is necessary to provide specific direction on what actually has to happen to the REC to be able to take the RPS adjustment,"[8] it does not fully acknowledge the fact that the RPS program is separately administered and tracked by other state agencies, and the REC retirement requirement is not necessary within the context of the Program. Covered entities subject to both mandates need to have the maximum flexibility within those programs. Requiring entities to retire RECs in the Cap-and-Trade program under time restraints that are not required by the RPS program will diminish the flexibility that was recognized by the RPS program authors.

The Proposed Amendments would revise 95852(b)(4) to allow the RPS Adjustment to be utilized by a covered entity as long as the REC is retired (as that term is used within the context of the California RPS program) "during the same calendar year **for** which the RPS adjustment is claimed." While M-S-R prefers to strike the provisions that require the REC to be retired within the language of the Regulation, M-S-R supports the proposed revision to the extent that it removes the requirement that the REC be retired "the same year **in** which" and replaces it with the text referenced above. The requirement to retire the REC *in the same year* the adjustment is claimed does not recognize that the electricity may be imported during a different year than when the associated REC is retired for compliance with the RPS program. The difficulties of matching electricity imports to REC retirement within a single calendar year are complicated by the fact that the RPS program has multi-year compliance periods through 2020, and RECs can be retired at anytime within 36 months of being generated. Requiring a REC to be retired in the same year the electricity is generated is also problematic given the fact that REC itself is not issued by WREGIS at the same time the underlying electricity is generated. Therefore, attempts to "annualize" the REC retirement requirement could dissociate the RPS Adjustment from the electricity import. M-S-R understands that the proposed changes to section 95852(b)(4) are intended to allow the RPS Adjustment to be claimed at the time the REC is retired without regard to the year in which the underlying electricity was imported/generated. While it is preferable for all matters regarding retirement of RECs to be addressed solely within the RPS program and not in the Regulation, this revision is helpful, as long as it can be

[89] California Air Resources Board. Final Statement of Reasons. October 2011. http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

reconciled with the current Mandatory Reporting Regulation (MRR). The MRR requires compliance entities to report emissions for all imports that occurred within the previous calendar year for purposes of calculating the entity's compliance obligation. This is also reflected in section 95852(b)(1)(B) of the Regulation that addresses how emissions with a compliance obligation are calculated and which reflects data reported under applicable provisions of the MRR. The Regulation needs to be consistent with the RPS program and workable within the construct of the processes employed by WREGIS for the issuance of RECs. Stakeholders need to know that the Regulation properly reflects the RPS program constraints and accurately acknowledges the associated complexities of the requirements set forth therein. If not clarified, it is possible that inadvertent restrictions on reporting the RPS Adjustment could hinder the ability of utilities that are covered entities under the Cap-and-Trade regulation *and* subject the State's RPS mandate to maximize their resource commitments in meeting the stringent requirements of both programs. To that end, M-S-R urges clarification to the Regulation that clarifies that the RPS adjustment is not intended to be associated with any specific electricity import. (MSR 1)

Comment: RPS Adjustment: Covered entities subject to the State's renewable portfolio standard mandates should not be required to retire RECs in order to utilize the RPS Adjustment. NCPA appreciates CARB's recognition of the interaction between the State's renewable energy mandate (RPS program) and the Cap-and-Trade program, both of which play critical roles in California's green-energy future. In order to fully reconcile these two programs, the Proposed Amendments should reflect the covered entities' obligations under the RPS program requirements, as those requirements are set forth in Public Utilities Code Section 399.11, et seq., and implemented by the California Public Utilities Commission (CPUC) and California Energy Commission (CEC). Accordingly, NCPA urges the Board to direct staff to propose amendments to the provisions of section 95852(b)(4)(B) to clarify the rules governing when the RPS Adjustment may be claimed, in light of the fact that the associated renewable energy credit (REC) may not be retired in the same year that the electricity is generated and imported under the RPS program.

As NCPA understands it, CARB is seeking to ensure that the RECs associated with renewable energy be placed into WREGIS so that they may be tracked without the risk of double counting. RECs generated by WREGIS, however, do not have to be retired within a year of generation, and it is important that the Regulation reflect this distinction. Since CARB first adopted the Regulation, the CPUC has moved forward with defining the RPS program requirements for CPUC-jurisdictional entities, and the CEC has adopted both the Seventh Edition of the RPS Eligibility Guidebook[90] and the RPS Enforcement Regulations for POUs.[91] Under the RPS program, RECs used to meet the RPS program mandates may be retired anytime within 36 months of generation.[92]

[90] Renewable Portfolio Standard Eligibility Guidebook, 7th Edition (RPS Guidebook); http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-CMF.pdf.
[91] Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (POU Enforcement Procedures) http://www.energy.ca.gov/2013publications/CEC-300-2013-002/CEC-300-2013-002- CMF.pdf.
[92] *See* Public Utilities Code section 399.21(a)(6), POU Enforcement Procedures, section 3202, and RPS Guidebook, Section V.C at p. 91.

NCPA urges CARB to look closely at the provisions of the RPS programs, including the RPS Enforcement Regulation, and particularly, to recognize that there are significant undesirable consequences and adverse impacts associated with constraining the ability of electric utilities to fully utilize the value of their RECs. NCPA urges the Board to direct amendments that strike the retirement requirement altogether. The Regulation should be amended to address the retirement requirements that are mandated under the State's RPS program, and not assigned an arbitrary deadline under the Cap-and-Trade Program. (NCPA 1)

Comment: Powerex understands the importance of the RPS Adjustment provisions as a key component of the Program as it relates to electricity markets. In Powerex's view, the focus of these provisions should be to ensure alignment with California's RPS program while maintaining accurate GHG emission accounting. Powerex is concerned that the provisions as proposed do not achieve the necessary alignment. Powerex's primary concern is specific to the proposed amendments to CTR § 95852(b)(4)(A) that would require the electricity importer to have title to the RECs associated with the eligible renewable resource in order to claim the RPS Adjustment. This requirement is not consistent with the rules governing the RPS program in which it is an accepted practice for the importer of the substitute electricity to import on behalf of an RPS regulated entity and to not have title to these RECs. In this case, it is common for the California entity subject to the California RPS, on whose behalf the importer is importing the substitute electricity, to retain title to the associated RECs. Many firming and shaping deals were contracted for with these requirements in mind, and on the assumption that the carbon costs would accrue to the importer of the substitute electricity since the California Public Utilities Commission's Decision on Product Content Categories, issued December 15, 2011, which would recoup these costs by claiming the RPS Adjustment. ARB's proposed amendment would require these existing contracts to be renegotiated, and unnecessarily narrow the contract structure flexibility for prospective firming and shaping deals.

Rather than proposing specific edits to the RPS Adjustment, Powerex supports the comments proposed by the Western Power Trading Forum in both of its sets of comments on ARB's Proposed Amendments to the CTR, dated October 16 and 23, 2013. (POWEREX 1)

Comment: And then lastly, with regards to what staff brought up during the presentation with the RPS adjustments, from an accounting perspective, it makes sense for the credit for the RPS adjustment to be taken in the same year as those -- that electricity was imported. When you're doing the report and you're reporting the import, the credit should be tied to that same year. But unfortunately, with the REC requirement that the RECs aren't going to be retired for two to three years down the road, if that credit is tied to REC retirement, the credit is going to be -- it's going to be disjointed. So you report the emissions in one year, and you claim credit in years down the road. That's really not the best way to do it from an accounting perspective. So we actually would encourage ARB to consider an alternative way to enable entities to claim that

RPS adjustment credit in the same year that you're actually reporting the electricity. So that way from an inventory perspective it makes a lot more sense. (LADWP 2)

Comment: Fourth, there is a new requirement that renewable energy credits or RECs must be retired in order to claim an RPS adjustment. The CEC and the CPUC administer the RPS program. The CEC and the CPUC have established rules governing the retirement of RECs for POUs and IOUs respectfully. The ARB should not be developing REC retirement rules that may be at odds with CEC or CPUC rules and which make it more difficult for utilities to meet their RPS goals. The ARB should adopt the same approach for the RPS adjustment RECs as for specified source RECs, namely, require the RECs serial numbers to be reported without requiring that the RECs be retired in the same year for which the RPS adjustment is claimed. (SCPPA 2)

Comment: LADWP appreciates CARB's efforts in working with electric utility entities to clarify the timing with respect to an entity claiming an RPS adjustment such that electric utility entities will not be required to prematurely retire their REGs under the California Energy Commission's Renewable Portfolio Standard (CEC RPS) Program. LADWP also supports CARB's amendments to require REC serial numbers to be reported instead of requiring the REGs to be retired to claim renewable specified imports. LADWP recommends that CARB require that REC serial numbers be reported under the RPS adjustment provision consistent with its approach to renewable specified imports so to not inadvertently interfere with electric utility entities' implementation of the CEC's RPS Program. (LADWP 1)

> **Response:** The purpose of the RPS adjustment is to provide an adjustment to a compliance obligation for the procurement of renewable electricity that can't be directly delivered to California. This adjustment recognizes the resulting compliance obligation for the replacement electricity, and the utility's costs associated with meeting the RPS. The Cap-and-Trade Regulation requires that the renewable electricity was procured to meet a utility's RPS obligation. If the importer is not a utility, then the importer must demonstrate a relationship with the utility, and between the utility and the eligible electricity or the importer and the eligible electricity. This relationship is demonstrated contractually, pursuant to MRR. The contractual relationship is important because this is where entities will resolve the compliance cost of this Regulation. ARB staff clarifies for the commenter the provisions do not <u>require</u> the importer to have title to the RECs. The term "procure" in section 95952(b)(4) merely means to <u>secure</u> the power and RECs on behalf of the utility, it does not require the purchase and title. However, if the importer is procuring the electricity and RECs on behalf of the California utility, then the importer will be transferring the RECs to the utility so the utility can use the RECs to meet its RPS compliance requirement.
>
> The clarification in section 95852(b)(4)(B) was to specifically state what action must be taken to provide evidence the REC has been retired. The REC must be retired for the reporting entity to be eligible to take the RPS adjustment. Some commenters suggest allowing entities to take the adjustment in the current

reporting period with the promise the REC will be retired in the future. ARB staff does not agree that reporting of REC serial numbers with a future commitment to retire RECs provides environmental integrity under the Cap-and-Trade Program as there is no mechanism in the Cap-and-Trade Regulation or MRR to verify the future retirement for an adjustment to a current compliance obligation. And there is no mechanism to retroactively adjust a compliance obligation if a utility did not retire the REC to meet RPS as promised. The regulation does not place any requirements on the entity to retire a REC in a shorter timeframe than allowed under RPS. The utility does not need to retire the RECs until it is necessary to satisfy its RPS obligation.

The commenters suggest matching the RECs to imported substitute power using the NERC e-tag functionality, rather than requiring the retirement of the REC. However, this suggestion would not prevent the REC from being transferred or sold after taking the adjustment to the compliance obligation. This suggestion does not resolve the potential for double counting of the REC's environmental attributes, which the retirement prevents.

One commenter further requests ARB staff require the RPS obligated entity submit an attestation stating the associated RECs will be used for category two RPS compliance. However, the covered entity under Cap-and-Trade is not always the RPS obligated entity and thus ARB has no regulatory jurisdiction to require them to submit an attestation. One commenter also submitted additional comments to suggest the utility submit an attestation and include a statement regarding which importers are eligible to take the adjustment, on their behalf, and that the utility itself attest it will retire the REC. However, the utility is not always the covered entity, and as such ARB does not always have jurisdiction to require the submittal of the attestation.

A commenter states there is uncertainty as to whether the provision applies to the substitute electricity, or the RPS eligible electricity. Another commenter requests a clarification the RPS adjustment is not intended to be associated with any specific electricity import. The RPS adjustment is not tied to the substitute power delivered in place of the eligible renewable electricity. The adjustment is based on the MWh designated in the contract for the purchase of the RPS eligible generation. There are no provisions within MRR that require the substitute electricity to be reported as associated with the eligible renewable electricity.

Another commenter suggests modifications that would allow retail providers to assign their RPS adjustment to another entity designated by that retail provider. The Cap-and-Trade Regulation does not contain provisions for assigning any part of an entity's compliance obligation to another entity, nor does it allow for the transfer of any adjustments between covered entities. The compliance obligation is the sole responsibility of the covered entity and any adjustments can only be claimed by the eligible entity. Transfers would unnecessarily complicate accounting for ARB and the covered entity.

A commenter suggests adding language to allow the importer to sell off the underlying renewable electricity. The provision only requires that the electricity and RECs be procured. ARB does not have any jurisdiction under this Regulation to state the importer is allowed to, or required to, sell off the electricity. The disposition of the electricity that is not able to be delivered to California is immaterial to the ability to claim the RPS adjustment.

Energy Imbalance Market

E-2.6. Comment: SCE appreciates that the EIM-related amendments included in the Proposed Regulation Order are broad enough to accommodate some potential modifications to the CAISO's proposed EIM design. However, there are still many EIM-related issues and processes that could considerably alter the EIM design before the Federal Energy Regulatory Commission ("FERC") approves a final EIM design. The ARB should be aware that its EIM-related language might require future alteration depending on the outcome of the EIM Proposal approval process. (SCE 1)

Response: ARB staff appreciates the comment and explanation provided, however, staff declines to make requested changes as the current language is sufficient given that the EIM market design has not been finalized through FERC approval. ARB staff believes the proposed language provides implementation flexibility for when the EIM market design is finalized. However, if warranted, ARB staff can always propose future amendments to address specific EIM design elements.

Qualified Export Adjustment

E-2.7. Comment: PG&E recommends that the current Qualified Exports (QE) adjustment calculation be amended to enable it to achieve its intended purpose of allowing a reduction in the compliance obligations of importers who simultaneously import and export electricity. The current calculation results in a QE adjustment equal to zero if there is any zero-emissions generation within an hour. For example, assume PG&E imports I00 MWh in an hour and exported I00 MWh in that same hour. If the imported electricity was 99 MWh of unspecified electricity and 1 MWh of solar, and the exported electricity was all unspecified, PG&E could not claim any QE adjustment, as the QE adjustment would be zero.

Recommendation: PG&E recommends changing section 95852(b)(5)(A)(2) to: "The lowest non-zero emission factor of any portion of the qualified exports or corresponding imports for the hour."

This amendment would be administratively simple to implement and would result in entities being able to use the QE adjustment as intended. (PGE 2)

Response: This comment is outside the scope of the proposed regulatory amendments, as ARB staff did not propose any amendments to this section. ARB staff notes the comment and is dedicated to monitoring reported data to determine whether future amendments to this provision are necessary.

E-3. Resource Shuffling

General Resource Shuffling Comments

E-3.1. Multiple Comments: The California Air Resources Board ("ARB") is responsible for minimizing leakage under the State's comprehensive climate policy, AB 32. Its task is perhaps most complex in the electricity sector, which is organized, regulated, and operated across state lines, and thus readily subject to a form of leakage called resource shuffling. This paper evaluates ARB's approach to regulating resource shuffling, critiques the implications of the current policy trajectory, and offers a proposed rule structure that attempts to reconcile multiple stakeholder interests in an environmentally robust and economically coherent framework.

Conceptually, resource shuffling occurs when a covered entity receives credit for emissions reductions that have not actually taken place. For example, if a California utility swaps its contract for 100 MWh of coal-fired electricity for a Nevada utility's contract for 100 MWh of natural gas-fired electricity, the California utility will be able to report a reduction in emissions, even though no reduction in physical emissions has taken place. In a nutshell, resource shuffling is what happens when a covered entity successfully "offshores" its greenhouse gas liability to an unregulated party.

ARB has previously identified a strong prohibition against resource shuffling as a top priority in its policy development process. The State's carbon market regulations flatly banned resource shuffling, but arguably did not define the prohibited practice in sufficient detail. In response to stakeholder concerns, ARB adopted an interim policy in the form of a staff guidance document. This guidance identifies a series of "safe harbor" provisions. (CULLENWARD 1)

Comment: The History of ARB's Resource Shuffling Rule. ARB has paid close attention to resource shuffling for many years, and has spent considerable time engaging stakeholders over the best way to address the issue in the California carbon market. During the development of its carbon market regulations in August 2011, for example, ARB identified three different practices that it would seek to ban:

- Cherry picking: replacing power that has an unspecified emissions factor with power that has a specified, lower emissions factor.
- Facility swapping: replacing power that has a high emissions factor with power that has a lower emissions factor.
- Laundering: replacing power that has a high emissions factor with power that has an unspecified emissions factor.

ARB continued to express this intention through May 2012, listing all three prohibited practices in a workshop document.[93] In addition, ARB indicated that it intended to exempt two new categories of activity from the definition: changes in electricity

[93] California Air Resources Board, Compliance Obligations of First Deliverers of Electricity, Staff Presentation at Electricity Technical Meeting (Aug. 26, 2011), available at: http://www.arb.ca.gov/cc/capandtrade/meetings/082011/cap-trade-presentation.pdf.

deliveries effected pursuant to state or federal law, and deliveries of emergency power.[94]

In September 2012, ARB issued its complete carbon market regulations. These regulations formally defined resource shuffling as follows:

"'Resource Shuffling' means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid."[95]

Using this formal definition, the regulations prohibit resource shuffling as a violation of the carbon market rules.[96] In addition, the regulations also require all first deliverers of electricity to submit formal attestations to ARB, with the attesting agent subject to penalty of perjury.[97] Although the regulations created a broad prohibition against resource shuffling, none of the detailed considerations found in prior workshop documents made their way into the final regulations.

Many stakeholders expressed concerns in response to the final regulations. Perhaps most prominently, Commissioner Phillip Moeller of the Federal Energy Regulatory Commissioner issued a public letter to California Governor Jerry Brown. In his letter, Commissioner Moeller asserted that ARB failed to clearly define resource shuffling. He argued that this failure, along with the associated attestation requirement, creates significant and undesirable market uncertainty. As a result, Commissioner Moeller asked California to suspend the resource shuffling prohibition until ARB clarifies the associated compliance and enforcement regime.[98]

ARB Chairwoman Mary Nichols responded publicly to Commissioner Moeller's letter, acknowledging the need for formal rulemaking to clarify the types of transactions that would fall under (or avoid) the resource shuffling prohibition. In addition, Chairwoman Nichols agreed to suspend the attestation requirement during the first 18 months of the program.[99] Notably, however, Chairwoman Nichols' letter made no indication that ARB intended to suspend or weaken the underlying prohibition on resource shuffling.
Over the following weeks, ARB's approach to resource shuffling evolved rapidly.

As ARB moves to conduct a formal rulemaking addressing resource shuffling in the fall of 2013, the Board should take a close look at the resource shuffling policy and design new ways to strengthen the rule while decreasing market uncertainty and avoiding potential conflicts with federal jurisdiction over regulation of wholesale electricity and energy futures markets. (CULLENWARD 1)

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[94] California Air Resources Board, Cap-and-Trade Program and Electricity Workshop, Staff Presentation at a Public Meeting to Discuss Compliance Requirements for First Deliverers of Electricity (May 4, 2012), available at:http://www.arb.ca.gov/cc/capandtrade/meetings/050412/may4electricityppt.pdf.

[95] *Id*.

[96] Cal. Code Regs., tit. 17, § 95802(a)(250).

[97] *Id*. §§ 95852(b)(A)-(B).

[98] Letter from Phillip Moeller to Edmund Brown (Aug. 6, 2012), available at: http://www.ferc.gov/about/com-mem/moeller/moeller-08-06-12.pdf

[99] Letter from Mary Nichols to Phillip Moeller (Aug. 16, 2012), available at: http://www.arb.ca.gov/newsrel/images/2012/response.pdf.

Response: The initial Cap-and-Trade Regulation, when it became effective on January 1, 2012, defined and prohibited resource shuffling, and required First Deliverers of electricity to submit attestations that they had not engaged in resource shuffling. During 2012, many stakeholders expressed concerns that the attestation requirement and other provisions of the resource shuffling prohibition could have negative effects on electricity markets and system reliability unless modified for greater specificity and clarity. A letter from FERC Commissioner Moeller to Governor Brown expressed the commissioner's concern about "potential disruption to California's electricity market"[100] that could arise from the regulation's approach were it not amended.

To address these concerns, after numerous stakeholder meetings and consultation with Federal and State energy and regulatory agencies and the California Independent System Operator (CAISO), ARB staff moved to suspend the attestation requirement during the first 18 months of the Cap-and-Trade program.

In October 2012, Board Resolution 12-51 directed staff, in consultation with the California Independent System Operator (CAISO), the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and stakeholders, to refine the definition of resource shuffling and to identify situations that ARB staff would not consider resource shuffling based on the proposal in Attachment A of Resolution 12-51. ARB staff was further directed to publish regulatory guidance consistent with Attachment A prior to the November 14, 2012 allowance auction and to return to the Board with proposed regulatory amendments consistent with Attachment A. ARB staff published guidance in early November 2012 that listed 13 transaction types that do not constitute resource shuffling. These 13 transaction types are informally known as "safe harbors." The guidance also identified two activities involving substitutions of lower emission electricity for electricity from high emission power plants that are not compliant with California's Emissions Performance Standard as resource shuffling[101].

The terms cherry picking, facility swapping, and laundering are useful concepts for understanding various activities that may be, but are not necessarily, resource shuffling. For example, the commenter defines cherry picking as replacing power that has an unspecified emission factor with power that has a lower emission

[100] Letter from Chairman Mary Nichols to Commissioner Moeller, FERC, August 16, 2012.

[101] The Emission Performance Standards, in regulations adopted by the CEC and the CPUC pursuant to SB 1368, prohibits California utilities from renewing long-term contracts with, or ownership arrangements in, power plants with emission rates greater than 1,100 pounds of CO2 per MWh, and limits significant investments in these facilities that would prolong their continue operation. As of February 28, 2014, the CEC regulation is available at: http://weblinks.westlaw.com/result/default.aspx?db=CA-ADC-WEB&docname=PRT%28ID49AB5A0D44E11DEA95CA4428EC25FA0%29+%26+BEG-DATE%28%3C%3D02%2F27%2F2014%29+%26+END-DATE%28%3E%3D02%2F27%2F2014%29+%25+CI%28REFS+%28DISP+%2F2+TABLE%29+%28MISC+%2F2+TABLE%29%29&findtype=l&fn=_top&jh=Article+1.+Provisions+Applicable+to+Powerplants+10+Mw+and+Larger+%28Refs+%26+Annos%29&jl=1&jo=20%2BCA%2BADC%2B%25c2%25a7%2B2900&ordoc=ID49A8E90D44E11DEA95CA4428EC25FA0&pbc=DA010192&rlt=CLID_FQRLT5929239717272&rp=%2FSearch%2Fdefault.wl&rs=WEBL14.01&service=Find&spa=CCR-1000&sr=SB&vr=2.0, and the CPUC decision at: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=435395

factor. In fact, it has always been the practice in California to purchase surplus hydroelectricity when it is plentiful and cheaper than fossil electricity. This is not resource shuffling, but instead is an economically driven choice that allows fossil generating units to run less. While ARB staff used these concepts in discussing resource shuffling prior to developing a regulatory approach, it was never the intent to indiscriminately prohibit all activity that may fall under the definitions.

ARB staff will continue to closely monitor any activity that appears to constitute resource shuffling to ensure enforcement of the prohibition and any activity that may entail leakage, and will take any steps necessary to prevent electricity sector emissions leakage to the extent feasible.

E-3.2. Comment: Brookfield appreciates the opportunity to submit comments on the proposed changes to the California Greenhouse Gas Cap-and-Trade Regulation (the "Cap-and-Trade Regulation"). Our comments are directed specifically at the language proposed for resource shuffling.

Brookfield supports the modifications proposed by CARB to the resource shuffling language in Section 95852 of the Cap-and-Trade Regulation to eliminate the attestation requirement as well as the addition of the safe harbors and specific examples that provide more clarity regarding the definition of resource shuffling. (BEM)

Response: ARB staff appreciates the commenter's support of the elimination of the resource shuffling attestation, modifications to the definitions, and of the safe harbors.

E-3.3. Comment: Portland General Electric (PGEC) applauds ARB in removing the resource shuffling attestation and incorporating the guidance documents into the Cap and Trade Regulation to provide some clarity on what would not constitute resource shuffling. However, PGEC encourages that ARB host a future workshop on this matter to explicitly provide examples of what would constitute resource shuffling so that stakeholders can engage in an educated discussion on how ARB intends to monitor, define and provide concrete examples of what ARB considers to be resource shuffling. (PGEC)

Response: ARB staff appreciates the commenter's support for the proposed amendments regarding resource shuffling. Although the commenter's request for a workshop does not address the proposed amendments, we note that ARB staff has held multiple workshops during the public process leading to the consideration of the Regulation that provided ample opportunities for ARB staff to provide examples of resource shuffling, and for stakeholders to discuss the issue and provide input. ARB staff will consider the commenter's request for a future workshop.

E-3.4. Comment: And finally, I'd like to speak to the issue of resource shuffling. We certainly don't share the concern by the gentleman from U.C. Berkeley about the potential adverse effects of the resource shuffling prohibitions. With you we do agree there is some remaining ambiguity and ask the Board reconsider its decision to not provide advisory opinions on this issue and provide stakeholders with a little bit more certainty on a question of resource shuffling provision by allowing for advisory opinions if stakeholders bring questions to the ARB. (TID 2)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Cap-and-Trade Regulation. ARB staff has committed to work with entities that hold long-term contracts or ownership shares in facilities that do not meet the EPS to address their transition towards divestment in order to ensure that the steps taken do not constitute resource shuffling.

E-3.5. Comment: On behalf of the Natural Resources Defense Council, and our more than 250,000 members and activists in California, we appreciate the opportunity to comment on staffs proposed amendments to the cap-and-trade program for consideration at the October 25thBoard hearing. These comments address only staff's proposal regarding resource shuffling. NRDC submitted separate comments on other aspects of the proposed amendments on October 16, 2013.

We appreciate staffs continued commitment to refine key aspects of the cap-and-trade program through an open and public process. Over the past few years, staff has held multiple public workshops to discuss the resource shuffling provisions and issued regulatory guidance documents to put stakeholders on notice for the current proposed amendments.

We also appreciate the challenge ARB faces in designing a rule that effectively prohibits resources shuffling, a form of leakage, within the limits of its jurisdictional authority. Pricing carbon creates an obvious market incentive to shuffle given the 'lack of comparable emission reduction requirements in other states that export power to California. We are optimistic that landscape will begin to change under EPA's existing source standards for power plants, however, which will apply in every state. We also recognize the tremendous impact the package of power-sector policies developed under AB 32 is having throughout the West by reducing both the demand for electricity and the carbon-intensity of electricity. (NRDC 2)

> **Response:** ARB staff thanks the commenter for their general support of the Cap-and-Trade program. ARB staff believes that the combined effect of the Cap-and-Trade Regulation, other California regulations that support AB 32, and the USEPA's regulations are already having a large effect in reducing emissions throughout the West, particularly at high emission coal power plants.

E-3.6. Comment: At Sec. 95852(b)(2)(A), for clarity, we suggest taking the language from Sec. 95852(b)(2)(B)— "substitutions of high with low" instead of "substitutions of low for high." Currently, the two sections are written differently and somewhat unclearly. (CRS 1)

Response: The commenter's request is not clear because section 95852(b)(2)(B) does not contain the quoted language "substitutions of high with low." Section 95852(b)(2)(A) is clear in stating that the listed "substitutions of electricity deliveries from a lower emission resource for electricity deliveries from a higher emission resource" are not resource shuffling. Section 95852(b)(2)(B) is focused on certain "prohibited substitutions of electricity of electricity deliveries from a higher emission resource with electricity deliveries from a lower emission resource" and again ARB staff believes that the regulatory language is clear.

Safe Harbors, General

E-3.7. Comment: SCE thanks the ARB for incorporating resource shuffling safe harbors into the Proposed Regulation Order. SCE believes that these safe harbors provide appropriate clarity to the industry in determining whether substitutions of electricity deliveries from a lower emission resource for electricity deliveries from a higher emission resource would constitute resource shuffling. (SCE 1)

Comment: Powerex welcomes the incorporation into the Regulation of the list of thirteen activities that ARB recognizes as not constituting resource shuffling, designated by ARB as "safe harbors" to the prohibition on resource shuffling. The safe harbors originally were set forth in Attachment A to Board Resolution 12-51 and later were incorporated into guidance promulgated by ARB in consultation with other state agencies, CAISO and stakeholders. (See ISOR at 30-31.) It is appropriate that these safe harbors be codified in the Regulation, thereby providing clearer and more lasting regulatory certainty than the guidance previously provided. (POWEREX)

Response: ARB staff thanks the commenters for the support.

E-3.8. Multiple Comments: 3.1 ARB's Safe Harbors Are So Broad as to Overwhelm the Prohibition on Resource Shuffling. A number of the safe harbor provisions in the Staff Guidance document are so broad that most electricity transactions can be structured to fit within their boundaries. As a result, the safe harbors permit market participants to engage in activities that cause massive, widespread leakage. We review each safe harbor in turn, using the paragraph number that corresponds to the listing in the Staff Guidance.[102]

Although we have policy objections to many of the safe harbors, the worst offenders are #6 and #8, which offer nearly unlimited potential for leakage. We are also extremely concerned about the potential for leakage from early divestment from out-of-state coal power, currently possible under safe harbors #2, #7, and #9. We quantify these leakage risks in Section 4.

Across the board, ARB could improve the quality of its approach by carefully delineating the requirements of each safe harbor; this is especially important for determining what

[102] California Air Resources Board, supra note 18, § A.4.

ARB means by referring to electricity deliveries that are "necessitated" by some other condition. Below, we review each safe harbor provision in order. (CULLENWARD 1)

Comment: Staff guidance identifies a series of "safe harbor" provisions. Meeting any of these provisions guarantees that a covered entity does not face legal liability for any possible resource shuffling. Although these safe harbors are not yet formalized in final regulations, ARB has just proposed amendments to the cap-and-trade regulations that would adopt them.

This paper analyzes the effect of ARB's current policy and its anticipated adoption in formal rulemaking later this year. In brief, we find that the safe harbor provisions set out in ARB's guidance document (and codified in its July 2013 discussion draft amendments) are so broad as to completely swallow the prohibition on resource shuffling. We find that almost all transactions can be structured to fit into several of the broadest provisions. On the basis of this finding alone, we believe ARB must reconsider its position in the upcoming rulemaking. (CULLENWARD 1)

Comment: A number of the safe harbor provisions are written so broadly, however, that we are concerned most electricity deliveries can be structured to fit within their scope. For example, in safe harbor two, what constitutes a delivery "made for the purpose of compliance with state or federal laws and regulations" would seem to encompass a wide range of transactions and possible interpretations. Many safe harbors also hinge on whether electricity deliveries were "necessitated" by some other condition (e.g., "electricity deliveries that are necessitated by termination of a contract," in safe harbor eight), which leaves ARB in the nearly impossible position of attempting to discern the intent or motivation behind a particular electricity delivery. (NRDC 3)

Comment: 6. Conclusions. We review ARB's approach to banning resource shuffling and find that the safe harbors developed in the Staff Guidance and codified in the July 2013 draft amendments are so broad as to overwhelm the rule. We find that almost all transactions can be structured to fit into several of the broadest provisions. (CULLENWARD 1)

> **Response:** The safe harbors specify which activities are not considered resource shuffling, including: changes in electricity deliveries that are required by law or regulation, electricity needed due to emergency situations, or electricity needed because an electricity deliverer has more than enough electricity to meet demand and therefore must reduce electricity delivered from some of the resources to which it has rights. Other safe harbors cover situations over which an electricity deliverer has no control, and most deliveries resulting from short term transactions such as those involved in CAISO's energy markets which are generally entered into without knowledge of the generation resource that will be tapped to supply the need.
>
> ARB staff developed the approach to the resource shuffling definition and provisions, including prohibited activities and safe harbors, after thorough

discussion with federal and state regulators, electricity importers and utilities, and the EMAC, in order to minimize emissions leakage to the extent feasible, as required by AB 32. ARB staff does not agree that the safe harbors are so broad as to swallow the prohibition on resource shuffling, or that almost all transactions can be structured to fit into them, because the safe harbors are carefully crafted for specific types of transactions as discussed in more detail in response to comments below about individual safe harbors under the heading *Safe Harbors*.

Safe harbors are required to facilitate transactions to occur that are needed to meet California's overall GHG emission reduction policies that work together with the Cap-and-Trade Program, to avoid conflict with other laws and regulations, and to avoid significant disruption of federally-regulated Western electricity markets that could negatively impact system reliability. Policies that work together with the Cap-and-Trade Program to reduce California's electricity-related emissions include the California's Renewable Portfolio Standard and Emission Performance Standards, federal criteria pollutant regulations (particularly those aimed at reducing regional haze), and Washington and Nevada laws that force the retirement of high emission coal power. The safe harbors for short term transactions are needed to allow for normal operation of electricity markets, in which trades are made very rapidly to reliably meet load, and provenance of each particular delivery is frequently unknown at the time of the transaction.

ARB staff has responded to comments related to specific safe harbor provisions under the subheadings for each specific safe harbor.

E-3.9. Comment: Over the following weeks, ARB's approach to resource shuffling evolved rapidly. On the eve of the state's first carbon market auction in November 2012, ARB directed its staff to prepare additional guidance documents employing a "safe harbor" approach.[103]

In response to stakeholder concerns, ARB adopted an interim policy in the form of a staff guidance document. This guidance identifies a series of "safe harbor" provisions. These safe harbors are activities that ARB does not consider to fall under the formal regulatory definition of resource shuffling, which remains in effect. A few weeks later, ARB staff released an update to its regulatory guidance documents, including each of the safe harbors identified in the Board Resolution (hereinafter the "Staff Guidance").[104] Although informal guidance does not have the same force of law as a statute or formal regulation, the guidance gives a picture of how ARB intends to interpret its regulations. This particular guidance is also, we argue, a reversal of ARB's prior stance on resource shuffling. As we discuss in Section 3, the current safe harbor approach is so permissive that the exemptions completely overwhelm the rule.

[103] California Air Resources Board, Resolution 12-51 (Oct. 18, 2012), available at: http://www.arb.ca.gov/cc/capandtrade/final-resolution-october-2012.pdf. See also Resolution 12-51, Attachment A, available at: http://www.arb.ca.gov/cc/capandtrade/attachmenta.pdf (specifying individual safe harbors).

[104] California Air Resources Board, Cap-and-Trade Regulation Instructional Guidance, Appendix A: What Is Resource Shuffling? Available at http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf (hereinafter the "Staff Guidance").

On July 18, 2013, ARB released draft amendments to its cap-and-trade regulations that codify the safe harbor approach proposed in the Staff Guidance.[105] While the draft regulations contain some changes—notably, new language that re-states the basic definition of resource shuffling[106]—the proposal is essentially identical to the Staff Guidance.

Most importantly for the purposes of this analysis, none of the safe harbors proposed by ARB in its draft regulations is substantially different than what the Staff Guidance proposed, nor has the basic logic of the Board's approached changed.[107] For convenience, our analysis here refers to current ARB policy by reference to the Staff Guidance document. Because the text of the proposed regulations are indistinguishable from the Staff Guidance document, however, our criticisms and suggestions apply equally well to the draft language provided by ARB on July 18, 2013.

3.2 The Structure of ARB's Safe Harbor Approach Is Too Permissive. By providing a list of safe harbor provisions, ARB presumably intends to create a more flexible regulatory regime that responds to stakeholder concerns. Unfortunately, the approach is too blunt as currently envisioned, as must be reformed.

Specifically, the November 2012 Staff Guidance document includes affirmative definitions of what constitutes resource shuffling. These definitions are provided in addition to the long list of safe harbors that exempt certain activities. The Board's proactive efforts here are largely wasted, however, as the Staff Guidance clearly indicates that any transaction falling into a safe harbor is completely exempt from liability.[108] Because the safe harbors are extremely broad, and because the Staff Guidance does not offer a coherent framework for resolving when a trading behavior may qualify for a safe harbor, this structural approach to the regulation is far too permissive.

There is nothing necessarily wrong about a rule structure that offers a reliable liability shield for qualifying activities. Indeed, many stakeholders would presumably place a high value on this outcome. Nevertheless, that approach requires explicit treatment about when a covered entity may claim a safe harbor. By failing to consider the potential for covered entities to include qualifying safe harbor transactions as part of a plan, scheme, or artifice to receive credit for emissions reductions that have not occurred, the

105 California Air Resources Board, California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Discussion Draft July 2013, available at: http://www.arb.ca.gov/cc/capandtrade/meetings/071813/ct_reg_2013_discussion_draft.pdf.

106 Id. § 95802(a)(252). Specifically, ARB proposed the following language: "Resource Shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A).

107 Id. (exempting certain safe harbors from the basic definition of resource shuffling); id. § 95852(b)(2) (codifying the Staff Guidance language as formal safe harbors).

108 California Air Resources Board, supra note 18, § A.5 ("Resource shuffling involves substitution . . .when such substitution does not qualify under the 'safe harbors' listed above.").

Staff Guidance permits malicious trading activity to take advantage of the generous safe harbor provisions in situations that it presumably did not mean to provide them.
As currently written, the Staff Guidance offers no assistance in determining when a single “activity” should be treated as part of a set of “activities” for the purpose of evaluating the resource shuffling rule framework. We believe that the Staff Guidance would permit a covered entity to tack on a qualifying safe harbor activity to an otherwise invalid activity or set of activities, and claim a liability shield on the overall transaction. As a result, the current structure broadens the safe harbor approach far beyond any reasonable outcome.

Unless either ARB either (1) reforms the language indicating that safe harbor provision are completely dominant over the affirmative definitions of resource shuffling, or (2) provides explicit limitations about when a set of activities can be integrated together for the purpose of applying safe harbors, the Staff Guidance can be easily exploited by parties who wish to avoid the basic prohibition on resource shuffling. We address both possibilities in Section 5.

Several of the proposed safe harbor provisions are so broad that almost any electricity sector transaction could be structured to fit within them, effectively negating the prohibition on resource shuffling. (CULLENWARD 1)

> **Response:** ARB staff disagrees that “the current safe harbor provisions are so permissive that the exemptions overwhelm the rule.” The safe harbors are carefully crafted to exempt market activities that are necessary for reliable functioning of the electricity markets and to harmonize the Cap-and-Trade Regulation with other California laws, regulations and policies that also address GHG emissions, among other purposes, as discussed in more detail elsewhere. The proposed amendment to the definition of resource shuffling has been modified to more clearly define what activities are considered resource shuffling. The proposed amendments to section 95852(b)(2)(B), which specifically prohibits resource shuffling associated with high emission power from resources that are not compliant with California’s Emissions Performance Standard (EPS), will effectively prevent shuffling associated with these coal power plants. ARB staff will enforce the resource shuffling prohibition, with a strong focus on ensuring that power from non-EPS compliant facilities is not shuffled. ARB staff notes that before the development of the proposed regulatory approach, potential coal resource shuffling was considered to fall under the conceptual categories of facility swapping or laundering, although these categories also include activities that may reduce overall WECC emissions.
>
> The proposed resource shuffling provisions are designed so that very specific transaction types are allowed to balance the need for a reliable electricity markets and the need to minimize emissions leakage, within the complexities of overlapping federal and state regulations, and the structure of electricity markets. The proposed amendments make it clear when a single activity should be recognized as part of a set of activities that is resource shuffling. This occurs

when one activity, namely delivery of power to California from a specified resource or unspecified resources, is part of a “plan, scheme, or artifice” that may include a variety of activities. For example, if entities enter into a contract to purchase power knowing that a compliance obligation will be avoided, then such actions would be considered resource shuffling, and both entities could be actively participating in the resource shuffling. This can be true regardless of whether or not one or more of the set of activities in the plan appears to fall within a safe harbor.

Safe harbor provisions are not dominant over the prohibited activities of for resource shuffling in section 95852(b)(2)(B). For example, safe harbor 10 may not be applied for short term transactions and contracts for electricity deliveries based on economic decisions including implicit and explicit GHG costs and congestion costs, if they are linked to the selling, or assigning of a contract for power from EPS non-compliant resources. Experience to date reveals that utilities with contracts with EPS non-compliant resources have consulted closely with ARB staff, providing very specific confidential information about potential contract and transactions, to ensure that their disposition of power from such resources does not constitute shuffling. Utilities continue to report that they will rely on these resources until their contracts end, or until they completely divest themselves of the facility ownership shares or contracts. ARB staff provide additional response on this topic in our discussion of safe harbors 9 and 10 and under the headings *Coal Leakage Analysis and Methodology* and *Definition of Resource Shuffling* below.

Safe Harbor 1

E-3.10. Comment: 1. “Electricity deliveries that are caused by the procurement of electricity eligible to be counted towards and purchased for Renewable Portfolio Standard (RPS) compliance in California.”

This provision appears to exempt any transaction involving the delivery of qualified renewable electricity to the grid. Thus, any strategy that results in leakage but involves renewable electricity would qualify for a safe harbor. This exemption would permit both cherry picking and facility swapping, as defined by ARB in prior workshop documents. For example, a utility that seeks to purchase qualifying renewable electricity could replace its unspecified imports (cherry picking) or specified imports from coal-fired or natural gas-fired sources (facility swapping) . (CULLENWARD 1)

Response: This safe harbor is necessary to harmonize this Regulation with the RPS. California’s RPS is one of the most important among the suite of measures complementary to the Cap-and-Trade Regulation that are all necessary to meet the GHG emissions reduction goals of AB 32. ARB staff expects that most if not all generation for RPS purposes, and the delivery of that electricity, will result in reductions in emissions on a net basis throughout the western states.

E-3.11. Comment: Change Proposed RPS "Safe Harbor". The proposed amendments would create a "safe harbor" from allegations of resource shuffling for: "Electricity deliveries that are caused by the procurement of electricity eligible to be counted towards and purchased for Renewable Portfolio Standard (RPS) compliance in California." AEPCO supports this safe harbor. However, AEPCO believes it should also apply to entities that deliver power to electric distribution utilities that are **exempt** from the RPS, but whose allowance allocation was calculated on the assumption that those entities would be required to meet the renewable energy targets embodied in California's RPS.

For example, certain electric distribution utilities (*e.g.*, electric cooperatives) are exempt from the requirements of the RPS. However, these entities' annual allowance allocations — which are to be used for protecting ratepayers from dramatic increases in electricity prices that could be caused by the cap-and-trade program—were determined using a formula that assumed that these entities would have to comply with the RPS, thereby lowering the allocations they might otherwise receive. *See* Appendix A to the ISOR for the 2010 Proposed Amendments to the Cap and Trade Regulation.

The RPS safe harbor correctly provides relief from the resource shuffling rules to those utilities that have an RPS obligation. However, the safe harbor currently does not permit RPS-exempt entities to reduce their compliance obligation to match their allowance allocation by substituting purchases of additional renewable energy for deliveries of higher-emitting electricity. As discussed above, it is possible that under the regulation as written, an RPS-exempt entity that purchases up to 33% renewable energy would be deemed to be resource shuffling, even though the entity was merely doing what ARB staff assumed it would do when ARB calculated that entity's allocation.

> **Recommendation:** *ARB should clarify that the RPS safe harbor also applies to the procurement of RPS-eligible renewable energy by the small number of RPS-exempt load-serving entities*. In the alternative, ARB should modify these entities' allowance allocations to remedy ARB's incorrect assumption that these entities would be subject to the RPS. AEPCO proposes adding the underlined text below:
>
> Section 95852(b)(2)(A). The following substitutions of electricity deliveries from a lower emission resource for electricity deliveries from a higher emission resource shall not constitute resource shuffling:
>
> (1) Electricity deliveries that are caused by the procurement of electricity eligible to be counted towards and purchased for Renewable Portfolio Standard (RPS) compliance in California <u>or, in the case of a first deliverer that delivers electricity to an electric distribution utility that is exempt from complying with the California RPS, deliveries of electricity that would otherwise be eligible for compliance with the California RPS.</u> (AEPCO)

Response: ARB staff does not believe that a change to this provision is necessary because there is no emissions leakage associated with procuring electricity from new renewable resources that help an EDU that is exempt from the California RPS to increase its percentage of renewable electricity. Because this does not result in emissions leakage, there is no concern for resource shuffling.

Safe Harbor 2

E-3.12. Comment: 2. "Electricity deliveries made for the purpose of compliance with state or federal laws and regulations, including the Emission Performance Standard (EPS) rules established by CEC and the CPUC pursuant to Senate Bill 1368."
Like the Renewable Portfolio Standard exemption above, this provision could exempt any transaction that relates to compliance with any state or federal law. What constitutes a delivery "made for the purpose of compliance" is too vague and permits covered entities to claim an extremely broad interpretation of this safe harbor.
Under such an interpretation, any transaction that includes a regulatory compliance feature would potentially be eligible for a safe harbor, even if it resulted in obvious and intentional leakage. For example, consider a utility that is bound to purchase electricity from a number of qualifying facilities, and claims that in response, it must shed its contract with a coal plant in order to comply with the requirement that it accept the qualifying facilities' power. The resulting transactions could be described as a compliance strategy, but also result in leakage. Such a broad interpretation would permit cherry picking and facility swapping, as defined by ARB in prior workshop documents. (CULLENWARD 1)

Response: First Deliverers of electricity must comply with state and federal laws and regulations and, in many cases, compliance may require them to substitute electricity with particular emissions attributes for electricity with different emissions attributes. Activities undertaken to comply with other laws and regulations should not be considered resource shuffling under the Cap-and-Trade Regulation. ARB staff disagrees that this provision is too vague. Electricity deliveries covered under this safe harbor are instances in which it is necessary for a First Deliverer to substitute electricity for other electricity with a different emission factor in order to comply with other laws and regulations. The hypothetical transactions introduced in the last paragraph might or might not result in resource shuffling, and would be looked at on a case-by-case basis by ARB staff. ARB staff will consider all resource shuffling provisions when evaluating whether specific actions constitute resource shuffling and take appropriate action.

E-3.13. Comment: Resource shuffling "safe harbors" should include activities to comply with rules, orders, or decisions issued by a governmental authority. Complying with rules, orders, or decisions issued by a governmental authority such as Least Cost Dispatch (LCD) requirements does not appear to qualify as resource shuffling based on the draft amended regulations. However, clear language in the Regulation is needed to affirm this interpretation.

First, PG&E recommends revisions to the draft regulations to clarify that activities consistent with PG&E's legal and regulatory requirements fall under the "safe harbors" and would not be considered resource shuffling. PG&E's proposed revisions are necessary because PG&E is required to meet its electric load obligations consistent with the CPUC LCD requirements.[109]

PG&E economically dispatches its resources, subject to regulatory, legal, operational, contractual, and financial requirements. To meet its LCD requirements, PG&E is required to dispatch resources or purchase energy with the lowest incremental cost. Accordingly, PG&E recommends changing Section 95852(b)(2)(A)(2) by adding the underlined text:

"Electricity deliveries made for the purpose of compliance with state or federal laws and regulations, including the Emission Performance Standard (EPS) rules established by CEC and the CPUC pursuant to public utilities code section 8340 et. seq<u>. or other rules, orders, or decisions by a state or federal governmental authority.</u>" (PGE 2)

> **Response:** Activities required as part of compliance with binding orders or decisions, and with governmental rules, would not be deemed resource shuffling if it can be demonstrated to ARB staff that the activities were necessary for such compliance. If it can be demonstrated it would fall under safe harbor 2 as the decisions to carry out these activities would not be undertaken as a plan, scheme, or artifice to reduce compliance obligation through substitutions of electricity deliveries. However, it is not uncommon for there to be apparent conflicts between multiple sets of requirements. For example, although least cost dispatch is required by more than one authority and in various jurisdictions and various venues, this does not necessarily override other requirements such as compliance with the RPS, or taking electricity from "must-run" resources. Likewise, there may be occasions when ARB's provisions to prevent resource shuffling take precedence over other requirements which themselves are not all-encompassing, therefore any potential resource shuffling would be reviewed by ARB staff on a case-by-case basis.

Safe Harbor 3

E-3.14. Comment: 3: "Electricity deliveries made for the purpose of compliance with requirements related to maintaining reliable grid operations, such as North American Electric Reliability Corporation (NERC) Reliability Standards, and Reliability Coordinator directives, including the provision of electricity between balancing authorities or load-serving entities when required to alleviate emergency grid conditions."

[109] CPUC Decisions mandate that PG&E dispatch its portfolio of existing resources, allocated California Department of Water Resources contracts, and market purchase to meet its electric load obligation in a least-cost manner. See CPUC Decisions 02-10-062, 02-12-069, 02-12-074, 03-06-076, 04-07-028 and 05-01-054.]

Absent minor reforms, covered entities could abuse this provision, tacking a qualifying safe harbor on to transactions that have no relationship to reliability standards. Specifically, it is possible to conceive of a malicious strategy that is designed to create or take advantage of grid reliability standards to enable resource shuffling. Although arguably a more remote concern than some of the broader loopholes we identify here—though in light of the trading behavior of companies like Enron during the California Electricity Crisis in 2000, perhaps not implausible—it is easily resolved without harming safety or reliability policy motivations. We propose a solution to this problem in Section 5.1. (CULLENWARD 1)

> **Response:** It is not clear exactly what the commenter means by "tacking a qualifying safe harbor on to transactions that have no relationship to reliability standards." However, if an entity is a party to multiple transactions, that together constitute resource shuffling, the fact that one of those transactions is protected by a safe harbor does not mean that ARB staff would not enforce the prohibition against that entity. This safe harbor provision is intended to provide assurance to market participants that when they must make transactions to comply with reliability standards or requirements, such activity will not be deemed resource shuffling. It would not be reasonable for the regulation to deem as resource shuffling transaction activity needed to prevent blackouts, grid failure or other dangerous consequences that can result in the absence of grid reliability.

Safe Harbor 4

E-3.15. Comment: 4: "Electricity deliveries made for the purpose of compliance with either a judicially approved settlement of litigation or a settlement of a transaction dispute pursuant to the dispute resolution terms and conditions of a contract for reasons other than reducing GHG compliance obligations."

The most compelling case for a safe harbor covering settlements is the argument that a flat prohibition on resource shuffling could result in a legal Catch-22 for a covered entity that is party to a settlement negotiation. If a judicial order in a settlement process would result in a covered entity receiving credit for emissions reductions that have not taken place, then that entity would be unable to reconcile the outcome of the settlement and the requirements of the carbon market regulations.

For example, imagine a dispute over a California's utility's contracts with out-of-state renewable and natural gas-fired power plants. Presume the California utility is, per the terms of the settlement, required to exit the gas contracts and take more of the renewable energy, while its out-of-state counterparty takes the reverse arrangement. As a result, the California utility will report lower emissions, despite a corresponding increase in out-of-state emissions. The California utility will be stuck in a bind: through good faith negotiations, the judicially approved dispute process placed the utility in violation of the basic prohibition on resource shuffling. This seems decidedly unfair to the utility, justifying the outcome provided by this safe harbor provision.

In our view, however, there is no reason a covered entity should be able to pursue or achieve resource shuffling through a settlement negotiation. On the other hand, it would not be efficient for a judge to have to anticipate the resource shuffling implications of proposed settlements. (CULLENWARD 1)

> **Response:** ARB staff agrees that, to avoid creating a legal "Catch 22", this safe harbor is necessary. ARB staff also agrees that a covered entity should not be able to pursue resource shuffling through settlement negotiation, and for that reason we have included the phrase "for reasons other than reducing GHG compliance obligations" to qualify and clarify this safe harbor.

Safe Harbor 5

E-3.16. Comment: 5: "Electricity deliveries that are necessitated by the retirement of resources."

Retirement is the clearest way to avoid leakage. Although this safe harbor is not necessary (because it is implied by the definition of leakage), it is a helpful restatement of the fundamental policy. (CULLENWARD 1)

> **Response:** Thank you for the support. ARB staff believes this provision is necessary because other stakeholders have requested that additional clarity be added to the resources shuffling provisions for these types of electricity deliveries.

E-3.17. Multiple Comments: LADWP recommends that Safe Harbor #5 be clarified to include electricity deliveries in the situation where a utility ramps down a higher emissions source and ramps up a lower emissions source. In this case, emissions reductions have occurred and thus should not be considered Resource Shuffling.

> **Recommendation:** Thus, LADWP recommends the following minor language change to Safe Harbor #5:
>
> (5) Electricity deliveries that substitute for power previously supplied by a specified source that has been retired <u>or has reduced its output</u>. (LADWP 1)

Comment: SCPPA commends the ARB on the changes to the resource shuffling provisions in section 95852(b)(2) of the Regulation. The revised provisions are consistent with the resource shuffling guidance developed by the ARB in 2012 after extensive consultation with electric sector stakeholders. However, it would be helpful to clarify that it is not resource shuffling if a high-emitting generator has been ramped down, reducing its power output and emissions, and the power is replaced with power from a low-emitting generator. This clarification can be made in "safe harbor" five, in section 95852(b)(2)(A)(5).

Recommendation: SCPPA's proposed change is the addition of the underlined text below:

(5) Electricity deliveries that substitute for power previously supplied by a specified source that has been retired <u>or that has reduced its output</u>. (SCPPA 1)

Response: ARB staff agrees that resource shuffling does not occur when a First Deliverer that controls multiple resources ramps down a high emissions source and ramps up a lower emissions source. However, we decline to make the requested change because ARB staff believes it would create an ambiguity. ARB staff believes that if the change requested by the commenters were made, it would be possible to reduce output from a high emissions source by a few percent, and then sell off all of the rest of the high emission power and replace it with low emission power, resulting in emissions leakage and resource shuffling. The more limited example in which ramping up a low emissions source substitutes for the same amount of ramping down a high emissions source is neither emissions leakage nor resource shuffling, but represents a desired outcome of the regulation.

Safe Harbor 6

E-3.18. Comment: 6: "Electricity deliveries that are necessitated by termination of a contract or divestiture of resources for reasons other than reducing GHG compliance obligation."

From our perspective, this is the second most problematic provision for two reasons. First, the requirement that the contract termination or divestiture is motivated by reasons other than reducing a compliance obligation is overbroad and vague. Under this provision, it appears that any party could elect to engage in resource shuffling, so long as it could make a colorable argument that it was motivated by something other than the resource shuffling implications of its actions.

Second, it is not clear which deliveries would be "necessitated" by contract termination or divestiture. Is replacing power deliveries from canceled contracts or divested interests necessary? After all, unilateral or mutually agreeable decisions to terminate or divest are not always necessary; but if these decisions create necessity, does that mean that parties can elect their way into necessity?

For example, consider a long-term contract between a California utility and an out-of-state coal power plant. Suppose the utility and power plant agree that the utility's long-term interests are best served by it investing more in generation assets the utility owns, rather than contracting with third party providers; as a result, they agree to terminate the contract on mutually agreeable terms. In this instance, the utility might claim that it was not motivated by GHG compliance obligations, and that, as a result of its contract termination, it would be necessary to acquire new renewable or natural gas supplies. In turn, the coal power plant might be able sell its power to other customers (e.g., those who were previously buying the natural gas or renewable power that was subsequently sold to the California utility). Under this safe harbor provision, the utility would appear to be able to avoid the prohibition on resource shuffling, despite the fact that resource shuffling would have actually occurred. Most importantly, the qualifying rationale—the utility's preference for ownership assets—could be replaced with any conceivably plausible business purpose.

Without specifying any standard for how ARB would review a party's purported motivations, and by permitting such a broad range of potential motivations to satisfy the safe harbor, this provision is readily subject to gaming by market participants. It is not clear that an enforcement action could proceed against an apparently misleading but colorable excuse under this safe harbor, even if ARB had the resources to show that GHG compliance motivations were significant while all alternative explanations were not.

The implications are particularly significant for out-of-state coal power interests, as we analyze in detail in Section 4. (CULLENWARD 1)

> **Response:** This provision is needed to clarify the difference between terminating a contract or divesting of a resource for legitimate business reasons, and doing so for the purpose of reducing GHG compliance obligations. It is not reasonable for ARB staff to attempt to control how First Deliverers terminate contracts when such termination benefits the First Deliverer and/or the ratepayers of a First Deliverer, unless such decisions are made as part of a plan, scheme, or artifice to engage in prohibited activity for the purpose of reducing compliance obligation.
>
> For the coal power plant example presented by the commenter, the transaction would be subject to the prohibitions of section 95852(b)(2)(B) and ARB staff would determine whether or not resource shuffling occurred based on all provisions in this section of the Regulation.

Safe Harbor 7

E-3.19. Comment: 7: "Electricity deliveries that are necessitated by early termination of a contract for, or full or partial divestiture of, resources subject to the EPS rules." This safe harbor provision appears to add little more than its predecessor, except that it specifically exempts a subset of termination or divestiture conditions that would already be covered under the previous safe harbor. Again, the implications for leakage from out-of-state are particularly severe. (CULLENWARD 1)

> **Response:** State policy, coordinated among several agencies including ARB, recognizes the benefit of encouraging California utilities to comply early with the EPS rules, including by terminating contracts or divesting of these resources. Therefore, this provision is needed to ensure that entities can divest of EPS-non-compliant resources early to fully comply with the intent of SB 1368. This

provision allows a California utility to transfer its share of a non-EPS-compliant facility (for example, newer, cleaner individual coal generation units) to an out–of-state utility under an arrangement that makes it possible for the out-of-state utility to shut down other units, resulting in significant, real GHG emissions reductions in the western states.

Safe Harbor 8

E-3.20. Comment: 8: "Electricity deliveries that are necessitated by expiration of a contract."

This is by far the most dangerous safe harbor, providing nearly unlimited potential for manipulation. The provision creates strong economic incentives to write short-term contracts or elective expiration provisions into their electricity contracts, providing a complete liability waiver for any subsequent activity. Surely ARB does not intend to provide an unlimited safe harbor, but the fact remains that this provision can be exploited to achieve nearly any end.

As with many other provisions, the breadth of the safe harbor turns on what is meant by "necessitated," a term that is especially confusing in the context of a complex market operated in real time. Exactly which electricity deliveries are "necessitated" by a contract's expiration: may a first deliverer of electricity substitute any power it wishes? (CULLENWARD 1)

Response: The operation of the western electricity markets involves many types of contracts of all lengths and kinds, with new types evolving to meet evolving needs. For the market to function reliably, it is necessary for a First Deliverer to be able to choose how to meet electricity needs for time scales from five minutes to many years based on what is available at a specific time in the market, or from owned or controlled resources, if any. If, when a contract expires, an entity needs to purchase electricity through new contracts, it would not be feasible or reasonable for ARB staff to categorically deem new choices as resource shuffling. This is not an unlimited safe harbor; it applies to cases in which a contract expires, and other activity is needed by the same or a different First Deliverer to meet system and end-user electricity needs. When a contract expires, utilities that must meet end-user needs, and marketers that help make this possible, will usually need to enter new contracts to keep the system functioning. The concept of substitution does not generally apply in these cases. Instead, there is an ending of a contract, and then the First Deliverer takes new actions as needed. Nonetheless, if there are electricity deliveries that occur after contract expiration meet the definition of resource shuffling, then those deliveries will not be included in this safe harbor.

Safe Harbors 9 & 10

E-3.21. Comment: 9: "Electricity deliveries pursuant to contracts for short term delivery of electricity with terms of no more than 12 months, for either specified or unspecified power, linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electrical Distribution Utility has a contract, or in which a California Electrical Distribution Utility has an ownership share, and based on economic decisions including congestion costs but excluding implicit and explicit GHG costs. In evaluating these short-term deliveries of electricity, ARB will consider the levels of past sales and purchases from similar resources of electricity, among other factors, to judge whether the activity is resource shuffling."

Carefully parsing this safe harbor shows that ARB intends to permit any short-term sales of high emission power contracts, especially from out-of-state coal power, if market participants can make a colorable economic argument about the desirability of the transaction without reference to compliance costs.

It is not clear under what circumstances the State could challenge a party claiming a safe harbor here, as to do so would require the State to analyze the entire economic decision-making framework and show that under no circumstances was the decision plausible without the inclusion of implicit or explicit greenhouse gas costs. Imagine trying to bring an enforcement action to prove a negative: the State would have to show that the first deliverer could only have been motivated by the avoided compliance costs, a complex inquiry in the context of interstate electricity markets. We are not convinced this safe harbor is narrowly tailored in such a way as to fairly balance the public's interest in minimizing leakage. (CULLENWARD 1)

> **Response:** ARB staff worked with the stakeholder community to carefully tailor this safe harbor to allow for specific types of electricity deliveries that are linked to selling off power from a non-EPS-compliant power plant. In general, such linked deliveries are prohibited under section 95852(b)(2)(B). However, congestion costs or other costs that are not GHG costs may result in a California EDU deciding to sell off power from such a power plant to minimize costs for ratepayers. This safe harbor allows for activity that would have been undertaken in the past, even without GHG compliance costs, to minimize costs.

E-3.22. Comment: 10: "Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months, or resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time market, for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under paragraphs 11, 12 or 13 below."

In contrast to our objections to the short-term exemptions for contracts arising from power plants that do not meet the EPS, we believe this safe harbor is more sensible. Although we cannot specifically justify why a 12-month limit is the right time horizon, permitting short term trading from EPS-compliant resources makes sense. The requirement that such trading clears the CAISO market seems like a reasonable way of assuring the economic integrity of affected transactions, increasing market certainty without undermining the environmental integrity of the carbon market. (CULLENWARD 1)

> **Response:** Thank you for the support. ARB staff chose to use a 12-month limit because typically in resource planning, utilities use transactions of up to 12 months to be able to respond to changing forecasts of weather (or other factors effecting load) and resource availability.

E-3.23. Comment: Additionally, WPTF requests that CARB clarify the following four aspects of the proposed language and staff comments made during the July 18 workshop and in the ISOR:

1. In response to a question regarding safe harbor 9 (i.e., proposed Section 95852(b)(2)(A)(9), as well as discussion of 95852 (b)(2)(B), CARB staff indicated that they would consider historic procurement patterns in determining whether an entity has engaged in resource shuffling. We ask staff to provide additional explanation regarding how this would work. If CARB intends to use some sort of procurement ‘baseline’ as a standard against which future procurement would be compared, then this should also be stated clearly in the regulation.

2. We are also concerned about a statement made by CARB staff that indicated that incorrect reporting of electricity under the Mandatory Reporting Regulation could be considered resource shuffling. This statement appears to be inconsistent with staff explanations provided to date indicating that resource shuffling is a cap and trade violation and involves the delivery of electricity – not the reporting of those deliveries. WPTF considers that a reporting error should be considered a reporting violation only – not resource shuffling. We believe that staff misspoke on this issue and request clarification.

3. Further, the explanation provided in the staff Initial Statement of Reasons (ISOR) regarding section 95852(b)(2)(A)(10) seems to contradict the regulatory language. Whereas the regulation provides a safe harbor for imports of electricity pursuant to short term transactions or contract or imports resulting from bids that clear the CAISO, the language of the ISOR suggest that the import must be pursuant to a short-term transaction or contract and result from a bid that clears the markets run by the California Independent System Operator (CAISO). This explanation changes the meaning of safe-harbor 10 and increases uncertainty. Modify the explanation of safe harbor 10 provided in Final Statement of Reasons to be consistent with the regulation.

4. Finally, we again ask CARB to provide an explanation to electricity deliverers as to how resource shuffling will be identified, as CARB has stated that this would not be a task of verifiers. In particular, we would like to understand how CARB will determine whether an electricity delivery is linked to the selling off or assigning of a contract from a high emission resource under contract to a California utility. We are concerned about the possibility that a first deliverer of power could be considered to have resource shuffled due to a procuring utility's sell off of high emission power, without the importing entity's knowledge of the sell off. (WPTF 1)

Response: Section 95852(b)(2)(A)(9) states that in evaluating short term deliveries linked to the selling off of power from non-EPS compliant power plants and based on economic decisions including congestion costs but excluding implicit and explicit GHG costs, "ARB staff will consider the levels of past sales and purchases from similar resources of electricity, among other factors, to judge whether that activity is resource shuffling." In this context, such consideration of historical sales and purchases is explicit for the linked transactions that are the subject of this safe harbor. This language was included to provide greater clarity for situations in which these linked deliveries may occur when high-emission power is sold off, not to avoid a compliance obligation, but in consideration of other reasons such as transmission constraints or congestion costs. Generally speaking, if ARB staff has cause to suspect resource shuffling, ARB staff will investigate and request all available data that would pertain to the determination of whether or not any particular transaction constitutes resource shuffling. Therefore, it is not possible to say in advance when historical procurement patterns would or would not be used in any particular potential investigation.

While incorrect reporting constitutes a violation of MRR, incorrect reporting in and of itself is not considered resource shuffling. However, if transactions underlying reporting are part of a resource shuffling plan, scheme, or artifice, and the accompanying reporting of the transactions are part of such activity, the combined activities could put a First Deliverer in violation of MRR reporting provisions and the Cap-and-trade Regulation's resource shuffling prohibition.

On the commenter's third concern ARB staff does not believe that language in the ISOR contradicts the regulatory language. The rationale provided in the ISOR for safe harbor 10 focuses only on CAISO markets; however, safe harbor 10 covers more than just CAISO market transactions, including short term transactions in general that are based on economic decisions including implicit and explicit GHG costs and congestion cost, if not linked to prohibited activities. This safe harbor specifically calls out CAISO market transactions to provide greater clarity for this important subcategory of transactions under safe harbor 10.

Finally the commenter asks how ARB staff will determine resource shuffling, in particular if a transaction is linked to the selling off of power from an EPS-non-compliant power plant. ARB staff monitor the electricity markets and deliveries of imported electricity to California, and if activities suggest resource shuffling, ARB staff would seek evidence of a plan, scheme or artifice to shuffle. ARB staff would use this monitoring data to investigate the possibility of resource shuffling.

E-3.24. Comment: Resource shuffling "safe harbors" should include activities resulting from participating in energy imbalance markets. Participating in the California Independent System Operator (CAISO) and PacifiCorp Energy Imbalance Market (EIM) or similar markets do not appear to qualify as resource shuffling based on the draft amended regulations. PG&E recommends that revisions that it recommended for safe harbor two should be accompanied by conforming changes shown in the first underlined section of "safe harbor" 10 below. PG&E also states that revisions to "safe harbor" 10 are also necessary to clarify that participation in an Energy Imbalance Market (EIM) does not constitute resource shuffling. The EIM involves an automated system over which participants cannot exercise control. To ensure ARB's intent is clearly communicated to all EIM participants.

Recommendation: PG&E recommends the following additions (underlined) to "safe harbor" 10:

Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months <u>or any transaction made for the purpose of complying with rules, orders or decisions by a state or federal governmental authority</u> or resulting from an economic bid, self-schedule, <u>award or similar mechanism</u> that clears the CAISO <u>or other</u> day-ahead or real-time market <u>or is generated in EIM or similar automated market,</u> for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under paragraphs 11, 12 or 13 below.

Finally, section 95852(b)(2)(A)(9) and (10) reference short-term contracts for deliveries of electricity with terms of no more than 12 months. However, it is possible for an entity to sign a contract with terms greater than 12 months, but with actual deliveries of 12 months or less.

Recommendation: To clarify that these transactions would not qualify as resource shuffling PG&E recommends the following change to Section 95852(b)(2)(A)(9) and (10): Electricity deliveries pursuant to contracts for short term delivery of electricity with terms of for no more than 12 months <u>in total</u>. (PGE 2)

Response: Activities required as part of compliance with binding orders or decisions, and with governmental rules, would not be deemed resource shuffling if it can be demonstrated to ARB staff that the activities were necessary for such compliance. If it can be demonstrated such an activity falls under safe harbors 9 or 10, because the decisions to carry out these activities would not be undertaken as a plan, scheme, or artifice to reduce compliance obligation through substitutions of electricity deliveries, then the activity would not be resource shuffling. However, it is not uncommon for there to be apparent conflicts between multiple sets of requirements. For example, although least cost dispatch is required by more than one authority and in various jurisdictions and various venues, this does not necessarily override other requirements such as compliance with the RPS, or taking electricity from “must-run” resources. Likewise, there may be occasions when ARB’s provisions to prevent resource shuffling take precedence over other requirements which themselves are not all-encompassing; therefore, any potential resource shuffling would be reviewed by ARB on a case-by-case basis. Therefore we decline to incorporate the commenter’s proposed language regarding transactions made to comply with rules, orders or decisions into safe harbor 10.

EIM transactions are by definition very short term transactions that represent the optimized economic dispatch of EIM participating resources through an automated process outside of any first deliver’s control. Therefore, the provisions of safe harbor 10, and the definition of resource shuffling, precludes EIM dispatch from being deemed resource shuffling and it is not necessary to make the changes requested.

The commenter requests that ARB staff make changes in proposed safe harbors nine and 10 to state that these safe harbors cover transactions for time periods that together sum to less than 12 months. Staff intent in providing safe harbors for short term transactions as specified in sections 95852(b)(2)(A)(9) and (10) was to recognize the differences between short term transaction decisions which generally have different dynamics and exigencies than longer term contracting for electricity that could supply demand that is known in advance by load serving entities and is dealt with through longer term planning processes. Some contracts, for example for peak power delivered under five year contracts for electricity during only certain times during the day or year, have more in common with other contracts with terms longer than a year, and less in common with the transactions ARB intended to address with safe harbors nine and 10. If ARB staff were to make the changes that the commenter proposes, the safe harbors would be expanded to the degree that transactions that clearly fit the definition of resource shuffling would be removed from potential enforcement, resulting in increased preventable leakage.

ARB staff also clarifies that a term of no more than 12 months means that the time from the beginning date to the ending date of deliveries under the contract must be no more than 12 months.

E-3.25. Comment: LADWP recommends that the term "CAISO" be struck from Safe Harbor #10 to apply to those transaction types that may occur in other balancing authorities, not just the CAISO. As stated previously, balancing authorities such as CAISO and LADWP function the same as the responsible entities that integrate resource plans ahead of time, maintain load-interchange-generation balance within their respective Balancing Authority Areas, and support Interconnection frequency in real time. (LADWP 1)

> **Response:** Safe harbor 10 applies generally to short-term transactions based on economic decisions including implicit and explicit GHG costs and congestion costs, unless linked to selling off power from an EPS non-compliant power plant under contract to a California utility. This is true regardless of whether a transaction occurs in CAISO, LADWP, or other balancing authority areas that may include portions of both California and other states. However, in the context of this provision CAISO and LADWP are not treated the same, even though they are both balancing authorities. LADWP is a load serving entity that does not operate a market; in contrast, CAISO is a market making entity that does not serve load, but facilitates transactions to serve load of utilities in its own and other balancing authorities. The language in safe harbor 10 is specific to CAISO because, as an independent system operator (ISO), CAISO's markets facilitate transaction types that cannot take place outside of an ISO.

E-3.26. Comment: However, the ARB should further modify Safe Harbor #10 to explicitly clarify that selling utility-owned power from a high-GHG resource that was first bid into the California Independent Systems Operator ("CAISO") markets to serve that utility's own load, but that was not scheduled through CAISO due to least-cost dispatch, would not be considered resource shuffling.

> **Recommendation:** SCE requests adding the underlined text below to Safe Harbor #10:
>
> 10. Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months, or resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time market, for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under paragraphs 11, 12 or 13 below. Selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, would not constitute resource shuffling if such power was first bid into the CAISO day-ahead or real-

time markets at the unit cost including GHG but did not clear the market and was subsequently sold outside of California. (SCE 1)

Response: ARB staff declines to make the requested modification. An electricity distribution utility has the option to schedule electricity from a power plant with which it has a long-term contract or ownership share as a zero bid transaction, in which case it will be delivered to supply the utilities load. Selling off high emission power and replacing it with lower emission power due to the reason provided by SCE is a form of resource shuffling. ARB staff's general understanding is that, utilities need to keep costs as low as possible for their ratepayers, and it is CPUC's job to ensure that they act in ratepayer interest to keep costs low. However, there are many instances where utilities have to do other actions that may result in higher ratepayer costs – the RPS requirements, or some energy efficiency programs, are examples. Staff believes that the policy need to accurately account for GHG emissions and reductions in emissions is important.

E-3.27. Comment: 2. Powerex Welcomes ARB's Proposed Codification of the Resource Shuffling "Safe Harbors" into the Regulation, But Safe Harbor No. 10 Requires Clarification. Safe Harbor No. 10, set forth in proposed section 95852(b)(2)(A)(10), is of particular importance. It provides as follows:

> Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months, or resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time market, for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under paragraphs 11, 12 or 13 below.

Frankly, however, this language is not a model of clarity. Powerex understands that Safe Harbor No. 10 is intended to apply to "short-term transactions and contracts for delivery of electricity with terms of no more than 12 months." Powerex interprets the word "term" within this context to refer to the actual electricity delivery period into California that is specified in the contract. It does not refer either to (a) the timeframe of the contract itself (*i.e.*, the time between the execution date and the end of deliveries under the contract), as the contract could, for example, be a forward contract executed several months in advance of the commencement of deliveries, or to (b) the contracting, scheduling or generating activities within the portfolio of the supplier. (*See, e.g.,* footnote 4, *supra*.) Powerex requests that ARB confirm that this interpretation is correct. (POWEREX 1)

Response: A "term of no more than 12 months" means that the time from the beginning date to the ending date of deliveries under the contract must be no more than 12 months. ARB staff intent in providing safe harbors for short term transactions as specified in sections 95852(b)(2)(A)(9) and (10) was to recognize the differences between short term transaction decisions which generally have different dynamics and exigencies than longer term contracting for electricity that could supply demand that is known in advance by load serving entities and is dealt with through longer term planning processes. Forward contracts that begin within a few months of the time in which they are agreed to, and are for a total term of no more than 12 months, are included in safe harbor 10. ARB staff also clarifies that a term of no more than 12 months means that the time from the beginning date to the ending date of deliveries under the contract must be no more than 12 months.

E-3.28. Comment: 3) The safe harbors defined for short-term trading activity contain vague language that creates too much uncertainty to be effective.
V. New proposed additions to the safe harbor language in 95852 (b)(2)(A)(9) for electricity imported under short-term contracts is problematic and should be deleted. In order for the markets to function efficiently there must be a clear safe harbor defined for short-term trading activities. The language designated below that is proposed to be added to section 95852 (b)(2)(A)(9) is ambiguous, problematic, and opens up an unknown range of possibilities that could deem a short-term transaction as part of a resource shuffling scheme. It is unclear how sales of other similar resources would be compared to or even be relevant towards evaluating a specific market transaction as part of a resource shuffling scheme. Even worse is the addition of the wording "other factors" that will be unknown and cannot be controlled by the First Deliverer. We propose this language be deleted from the proposed regulation:

> In evaluating these short term deliveries of electricity, ARB will consider the levels of past sales and purchases from similar resources of electricity, among other factors, to judge whether the activity is resource shuffling.

VI. CARB must define in the regulation what comprises a linked activity as it is used in Section 95852 (B)(2)(a)(10).

Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months are included as a safe harbor unless, as the regulation states, "such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share…."

CARB must be clear in the regulation as to what comprises a linked activity for this safe harbor to be of any value. Again, this raises concern as to whether the linked activities referenced herein are activities performed by the First Deliverers themselves or by another entity. The ambiguous reference to linked activities could potentially expose a First Deliverer to risks that are beyond its control and continued concerns regarding liability for resource shuffling due to another parties' actions.

VIII. Conclusion. The development of resource shuffling language that provides sufficient clarity to provide market certainty continues to be a challenge. The more ambiguous and broad the language remains the larger the burden that will be placed on CARB to resolve market uncertainties as well as increased exposure to legal challenges. (BEM 1)

> **Response**: ARB staff disagrees that the safe harbors for short term trading activity (safe harbors nine and 10) contain vague language that creates too much uncertainty to be effective. Both safe harbors nine and 10 are carefully worded to address very specific situations. The language to which Brookfield objects specifically affects short term transactions that are linked to the selling off of high-emission power and based on economic decisions that include congestion costs but exclude implicit and explicit GHG costs. This language provides additional clarity to entities engaging in these particular transaction types, and deleting this language would only increase uncertainty.
>
> ARB staff believes it is unnecessary for staff to define a linked activity in these provisions. A complete reading of ARB's treatment of resource shuffling begins with the definition which states that resource shuffling is a "plan, scheme, or artifice" designed to reduce compliance obligation. A linked activity would be linked through such planning activities intended to reduce the First Deliverer's compliance obligation through a prohibited substitution of low emission for high emission power.

Safe Harbors 11-13

E-3.29. Multiple Comments: 11: "Electricity deliveries that are necessitated by operational emergencies or transmission or distribution constraints, including constraints caused by the inability to obtain or retain transmission rights, transmission curtailments or outages, or emergencies."

Unless a covered entity conspires to abuse this provision, it is entirely appropriate in our view. We anticipate this possibility in our proposal in Section 5, which attempts to provide reliable safe harbors while preserving the possibility of enforcement where evidence explicitly indicates malicious intent. (CULLENWARD 1)

Comment: 12: "Electricity deliveries that are necessitated because a First Deliverer has surplus electricity (more than enough to meet demand) as a result of the First Deliverer being required to take electricity from specific generating units (e.g., electricity contracts with "must-take" or "must-run" provisions.)"

Again, unless a covered entity conspires to abuse this provision, it is entirely appropriate in our view. We address this possibility in our proposal in Section 5. (CULLENWARD 1)

Comment: 13: “Deliveries of electricity that are required to make up for transmission losses associated with electricity deliveries in California.” Again, unless a covered entity conspires to abuse this provision, it is entirely appropriate in our view. We address this possibility in our proposal in Section 5. (CULLENWARD 1)

Response: Thank you for the support.

Additional Safe Harbor Provisions

E-3.30. Comment: C. New Safe Harbor for Greenfield Zero-Emission Facilities. ARB should consider adding an additional safe harbor for the substitution of zero-emitting electricity from new, greenfield facilities for higher-emitting electricity. Unlike the “facility-swapping” that is possible among existing facilities, there is no basis for assuming that the addition of a new zero-emission facility to the grid will cause an offsetting increase in GHGs elsewhere in the western interconnect. Rather, the addition of new renewable generation to the grid displaces other existing generation (typically marginal fossil-fuel generation) or meets wholly new demand. Therefore, the substitution of power from a new greenfield zero-emission sources such as a wind farm or solar facility for higher-emitting power should not be considered resource shuffling, because it is not associated with leakage. However, ARB’s current and proposed resource shuffling regulations could be interpreted to prohibit such transactions because such transactions could be viewed as plans or schemes “to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce [an] emissions compliance obligation.”
Absent an amendment, uncertainty about the scope of the “resource shuffling” prohibition will discourage investment in new zero-emitting generation sources, which can reduce overall emissions throughout the Western interconnect without leakage.
Proposed solution: ARB should add an additional safe harbor under section 95852(b)(2)(A) for “substitutions of zero-emission electricity from new greenfield sources that replaces deliveries of higher- emission electricity from existing sources.” Alternatively, ARB should clarify in guidance that such substitutions do not meet the criteria for resource shuffling or leakage because they do not cause an offsetting increase in emissions outside the state (see our comments about this requirement in section I.A above). (AEPCO)

Response: ARB staff agrees with the commenter that addition of new zero-emission facilities will not cause leakage; therefore, there is no resource shuffling and this does not need to be added into the Regulation.

E-3.31. Comment: Proposed Changes to the Resource Shuffling Definition – Increased Emissions Due to Demand Growth. According to ARB, the prohibition on resource shuffling is intended to forestall schemes in which a first deliverer *appears* to reduce its emissions while in actuality continuing to emit at the same rate as before. *See* ISOR at 30. One of the prime examples of resource shuffling is “facility swapping” in which a first deliverer with one customer in California and another outside the state conspires to send high-emitting power that was previously going to the in-state customer to the out-of-state customer, while simultaneously delivering low- emitting power that was previously going to the out-of-state customer to the California customer.

However, it is possible that a situation could arise in which a first deliverer would attempt to reduce its overall emissions (*e.g.*, by fuel switching from coal to natural gas, or by delivering new, additional zero-carbon energy while reducing deliveries of high-emitting electricity) but the first deliverer's overall emissions would nevertheless go up on a year-over-year basis due to increased demand for electricity from outside the state. Accordingly, there is a risk that the first deliverer would be accused of resource shuffling due to the appearance of an "offsetting increase in emissions", even though the first deliverer did not plan or scheme to "facility swap" or resource shuffle. However, this situation does not constitute "leakage" because the increase in emissions out of state is due to an *exogenous* increase in electricity demand and not an attempt to avoid California's greenhouse gas rules.

Proposed solution: ARB's regulations do not adequately address this example, which could affect nearly every covered entity that sells to customers outside of California. Therefore, ARB should clarify that such a situation would not constitute resource shuffling. In particular, ARB should clarify that a "plan, scheme, or artifice" does not cover substitution scenarios in which an increase in emissions outside of California is caused by an increase in out-of-state electricity demand.

ARB should either clarify this point in future regulatory guidance, or the agency should include an additional safe harbor to make clear that substitutions that are *not designed* to lead to increases in emissions outside of California are not resource shuffling. (AEPCO)

> **Response:** ARB staff agrees with the commenter that an increase in a First Deliverer's total emissions due to increasing demand outside of California is not considered leakage, and would not fit under the basic definition of resources shuffling as a "plan, scheme, or artifice" to reduce compliance obligations; therefore, there is no resource shuffling and this does not need to be added into the Regulation.

Leakage

E-3.32. Multiple Comments: I am writing to raise serious concerns regarding the Board's proposed amendments to the rules on resource shuffling in § 95852(b)(2) of the September 4, 2013 Proposed Regulation Order. Please find my detailed comments in the attached San Jose Mercury News OpEd[110] and Stanford Law School working paper[111].

[110] Danny Cullenward, "Don't Let Accounting Tricks Dominate the California Carbon Market."San Jose Mercury News OpEd (October 22, 2013), available at: http://www.mercurynews.com/opinion/ci_24354840/danny-cullenward-dont-let-accountingtricks-dominate-carbon?source=rss

[111] Danny Cullenward and David Weiskopf (2013), Resource Shuffling and the California Carbon Market. Stanford Law School Environmental and Natural Resources Law & Policy Working Paper, available at: http://www.law.stanford.edu/organizations/programs-andcenters/environmental-and-natural-resources-law-policy-program-enrlp

In brief, I am concerned that the proposed exemptions to the prohibition on resource shuffling would violate the Board's obligation to minimize leakage under California Health & Safety Code § 38562(b)(8). As a number of studies have recently shown, a strong rule on resource shuffling is required to avoid substantial leakage in the electricity sector.[112] (CULLENWARD 1)

Comment: This policy trajectory does not satisfy the statutory requirement that ARB minimize leakage in its carbon market regulations. The current approach is also economically unjustified in light of the fact that ARB has already provided free allocations to utilities on the basis of their future greenhouse gas emissions and expected compliance costs. We believe that a decision to permit significant leakage through resource shuffling undermines the economic and environmental integrity of what has already become the most important carbon market in the world, and call on ARB to revise its approach. (CULLENWARD 1)

Comment: 2.1 California Law Requires ARB to Minimize Leakage. ARB is required by law to minimize leakage in its design of the cap-and-trade program for greenhouse gases. Under AB 32, leakage is defined as “a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.” Cal. Health & Safety Code § 38505(j). Resource shuffling creates leakage because an entity that engages in this activity reports emissions reductions that are matched by an increase in emissions outside the state. Recognizing that leakage undermines the purpose and efficacy of state climate policy, the California legislature required the Air Resources Board to “minimize leakage.” *Id*. § 38562(b)(8). This requirement is more than an aspiration. ARB must minimize leakage “to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit.” *Id*. § 38562(b). Thus, ARB may not adopt a regulation that fails to minimize leakage when alternatives that reduce leakage further are available and feasible.

Because the legal requirement to minimize leakage is clear, ARB would open itself to litigation risk from environmental advocates and climate policy opponents of any persuasion if it adopts a policy that does not minimize leakage. Equally important, any decision by ARB that facilitates large amounts of leakage undermines the goals and purpose of the state’s climate policy. As a result, ARB needs to maintain a focus on minimizing leakage as it proceeds to fully define resource shuffling in a new rulemaking. I strongly urge the Board and Staff to consider the significant implications of a weak rule on resource shuffling and modify its approach to fully address the leakage problem. Thank you for your consideration. (CULLENWARD)

Comment: One last word. The statute under AB 32 requires this Board to minimize leakage in the design of the market-based regulations. I cannot see how a vague and broad set of safe harbors that essentially would upend the prohibition on resource

[112] For example, see James Bushnell, Yihsu Chen, and Matthew Zaragoza-Watkins (2013), Downstream Regulation of CO2 Emissions in California’s Electricity Sector. Energy Institute @ Haas Working Paper #236, available at: http://ei.haas.berkeley.edu/pdf/working_papers/WP236.pdf

shuffling would be consistent with that. And I urge you to -- strongly urge -- you to revisit the recommendation before you. (CULLENWARD 2)

Comment: Save Our Peninsula Committee opposes the proposed amendment. I refer to research work undertaken by Danny Cullenwood and David Weiskopt in a recent Stanford Law School working paper. The paper shows that the Board's exemptions will permit rampant resource shuffling, which could result in leakage that exceeds the cumulative mitigation required under the cap-and-trade market through 2020. (ROSENTHAL)

Comment: The Air Resources Board vote to amend the successful carbon market regulations may create adverse leakage problems. Leakage solution: Allow any and all trading in the electricity sector - but if a trade results in leakage, the party divesting from a high-emitting resource must retain the liability for the emissions that leak out of California's market. Do not allow any leaks to occur in the carbon market regulations! (KBONE)

> **Response:** ARB staff must balance the requirement to minimize leakage, with the requirement of HSC section 38562(a) to adopt measures that "achieve the maximum technologically feasible and cost effective reductions" in GHG emissions, and with the requirements set forth in HSC sections 38562(b)(1-9), including "to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit" minimize leakage and also accomplish the other goals set forth in this section.
>
> ARB staff has developed the resource shuffling provisions taking into account other federal and state laws, federally mandated market structures, existing electricity market structures under federal authority, and the need for reliability of the interstate electricity grid, which is needed to ensure that the Cap-and-Trade Regulation works in concert with existing regulatory and market structures. ARB's Regulatory provisions must also remain within the limits of California's jurisdictional reach.
>
> In 2012, FERC Commissioner Moeller, in a letter to Governor Brown, expressed extreme concern about "potential disruption to California's electricity market" that could arise from the Regulation's approach was it not amended. Based on the input from FERC and stakeholders that participate in the complex electricity markets, ARB staff crafted the proposed resource shuffling provisions to clarify the resource shuffling prohibition, and to avoid market disruption. This approach, first described in guidance, is now incorporated into the proposed amendments. ARB staff believes that proposed amendments minimize leakage "to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit." Staff believes that it has taken the best approach to balance the many competing needs, including minimizing leakage, in a practical manner given the realities and complexities of the overlapping regulatory regimes and electricity markets.

E-3.33. Multiple Comments: But the scope of potential leakage resulting from unchecked resource shuffling in California's carbon market is significant if the proposed amendments are adopted without further modification. (NRDC 3)

Comment: Analysis: Safe Harbors. Several respected economists have recently noted the potential for significant leakage from resource shuffling. For example, Professor Bushnell of UC-Davis and colleagues recently modeled the leakage risks associated with not having a rule on resource shuffling. Simulating future generation across the grid managed by the Western Electricity Coordinating Council (the western interconnect), they find that emissions increases outside of California largely counteract the in-state reductions under a variety of scenarios[113].

Five distinguished economists who work on (or for) ARB's Emissions Market Assessment Committee ("EMAC") echoed these concerns in a draft report produced under contract with ARB.[114] They suggest that a permissive prohibition on resource shuffling could result in a range of cumulative 120 to 360 million metric tons CO2e, presuming that leakage from out-of-state coal power is not permitted.[115] Furthermore, the authors acknowledge that the lack of an effective prohibition on resource shuffling could result in as much leakage as 428.3 million metric tons CO2e.[116]

Although top economists have identified the clear potential for leakage from a weak rule on resource shuffling, no public assessment to date scrutinizes the actual regulatory framework ARB has adopted. Here, we evaluate that structure and connect our concerns to the published work on the potential for significant leakage.
In light of these conclusions, we urge the EMAC to revisit the problem of resource shuffling, focusing on the text of current regulations, current ARB guidance documents, and proposed modifications to both. These efforts are particularly important in light of the EMAC's role as a public advisory body to ARB: as part of its stakeholder engagement mandate, the EMAC is expected to "review stakeholder concerns and prioritize them for economic analysis."[117] Our findings suggest the EMAC members' draft lower and upper bound estimates for leakage in the electricity sector should be revised significantly upwards. The concerns we express also call attention to the need for independent economists to suggest solutions. (CULLENWARD 1)

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113 Bushnell, J., Y. Chen, and M. Zaragoza-Watkins, M., Downstream Regulation of CO2 Emissions in California's Electricity Sector, Energy Institute @ Haas Working Paper #236 (January 2013), available at http://ei.haas.berkeley.edu/pdf/working_papers/WP236.pdf.

114 Pursuant to an agreement between ARB and the University of California Energy Institute, the EMAC provides expert analysis and advice to ARB on market design, operation, and monitoring issues. See California Air Resources Board, Emissions Market Assessment Committee webpage, available at http://www.arb.ca.gov/cc/capandtrade/emissionsmarketassessment/emissionsmarketassessment.htm.

115 Bailey, E.M., S. Borenstein, J. Bushnell, F.A. Wolak, and M. Zaragoza-Watkins, Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market (March 12, 2013), § 5, draft white paper available at http://www.stanford.edu/group/fwolak/cgibin/sites/default/files/files/BBBWZ_POWER_final(1).pdf. Note that although the authors are affiliated with the EMAC, the draft report does not represent ARB's official position on any issues.

116 *Id.*

117 See California Air Resources Board, Emissions Market Assessment Committee webpage, supra note 38.

Response: The economic analyses referenced by the commenter create ranges of worst case possibilities. The models used by members of the EMAC simulate least cost dispatch with simplified transmission path limitations, but assume virtually no other limitations except for particular model runs that assume that California utilities will continue to purchase power until the ending dates of contracts or ownership agreements with EPS non-compliant out-of-state power plants. The default assumption is that that all high emission power possible will be imported to California whenever the relatively unlimited models indicate that such imports would be part of an overall minimization of simplistically modeled costs.

The models in question do not account for 'must-run' generation, the limitations on dispatchability that vary plant-by-plant, variable costs to operate at variable levels of output to the extent possible for each power plant, the requirements of RPS programs throughout the Western states, or the effects of Canadian greenhouse gas programs such as British Columbia's carbon tax. These models also do not account for the past and ongoing effects of increasingly stringent federal policies regulating criteria pollutants. On May 30, 2012, the Environmental Protection Agency (EPA) issued a final action revising rules that pertain to how certain states can meet specific requirements of the agency's regional haze program. The rule requires that source-specific best available retrofit technology (BART) be installed in the western states, typically on a facility basis. EPA has also agreed that the retirement of certain units within a facility may reduce the regional haze pollutants sufficiently that other units at the facility may continue to operate with retrofit technologies that are less costly than BART. As a result, coal units in western coal plants, including some in which California utilities have contracts, have been retired, and western states and utilities are planning for additional coal unit retirements significantly reducing GHG and criteria pollutant emissions. Because the models do not consider the interaction of the Cap-and-Trade Regulation and the limitations imposed by other regulations laws, and rules of multiple jurisdictions, they do not accurately estimate the potential for leakage.

Free Allowances and Leakage

E-3.34. Comment: Working paper section 2.2 ARB's Decision to Allocate Free Allowances to Utilities Encourages Leakage, Absent a Strong Prohibition on Resource Shuffling. The statutory requirement to minimize leakage is especially important in light of ARB's commitment to provide free allowances to electric utilities for ratepayer benefit. Free allocations provide an additional incentive for leakage in the electricity sector, and unless the definition of resource shuffling clearly prohibits anticipated forms of leakage, it will therefore be doubly vulnerable to exploitation by actors in the electricity sector. In particular, utilities could use a weak resource shuffling rule to (1) reduce compliance obligations via leakage, and (2) overcompensate their customers or shareholders by relying on ex ante allocation schedules determined on the basis of their relatively high

historical emissions[118]. Thus, a commitment to free allocations to utilities recommends additional safeguards against leakage in the definition of resource shuffling.
Although these requirements force utilities to demonstrate that the direct use of carbon revenue benefits ratepayers, it is possible that investor-owned utilities could develop creative accounting strategies to shift the balance of ratepayer and shareholder benefits through other means. Presumably both ARB and the California Public Utilities Commission will monitor this possibility; however, we note that the current CPUC Order establishing the framework for acceptable utility treatment of carbon allowance revenue prioritizes customer compensation for the rate impacts of the cap-and-trade system above a per capita rebate of the revenues. See CPUC, Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities, Decision 12-12-033 in Rulemaking 11-03-012, at 205-206. Notably, implementation of that Order will depend on the extent to which utilities are able to avoid compliance costs by relying on a weak resource shuffling rule. A weak rule will significantly mitigate rate impacts by enabling leakage. As a result, the CPUC will need to monitor the outcome of the resource shuffling policy to appropriately implement its Order.

While we do not accuse any utility of acting in bad faith, it is reasonable to consider the full range of regulatory incentives. Our point is that an argument that the restricted use of allocation revenues resolves any concern about the distribution of costs and benefits under AB 32 is facile. Any such argument ignores the complex relationship between utilities and their regulators. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it addresses allocation to utilities; therefore no response is required. Allocation of free allowances to utilities provides an economic incentive for utilities to reduce GHG emissions through activities that are neither leakage nor resource shuffling. ARB staff's enforcement of the prohibition on resource shuffling will prevent and deter utilities from seeking to reduce costs by resource shuffling.

E-3.35. Comment: Working Paper 2.2.1 ARB Provides Free Allocations to Covered Entities. ARB has already spent considerable time evaluating leakage in the context of regulated industrial activities. See, e.g., ARB Cap-and-Trade Technical Workshop to

[118] Investor-owned electric utilities are required to use all proceeds from initial allocations exclusively to benefit their ratepayers. Cal. Code Regs., tit. 17, § 95892(d). Utilities must also report their use of associated revenues to ARB, demonstrating compliance with this restriction. Id. § 95892(e). Although these requirements force utilities to demonstrate that the direct use of carbon revenue benefits ratepayers, it is possible that investor-owned utilities could develop creative accounting strategies to shift the balance of ratepayer and shareholder benefits through other means. Presumably both ARB and the California Public Utilities Commission will monitor this possibility; however, we note that the current CPUC Order establishing the framework for acceptable utility treatment of carbon allowance revenue prioritizes customer compensation for the rate impacts of the cap-and-trade system above a per capita rebate of the revenues. See CPUC, Decision Adopting Cap-and-Trade Greenhouse Gas Allowance Revenue Allocation Methodology for the Investor-Owned Electric Utilities, Decision 12-12-033 in Rulemaking 11-03-012, at 205-206. Notably, implementation of that Order will depend on the extent to which utilities are able to avoid compliance costs by relying on a weak resource-shuffling rule. A weak rule will significantly mitigate rate impacts by enabling leakage. As a result, the CPUC will need to monitor the outcome of the resource shuffling policy to appropriately implement its Order. While we do not accuse any utility of acting in bad faith, it is reasonable to consider the full range of regulatory incentives. Our point is that an argument that the restricted use of allocation revenues resolves any concern about the distribution of costs and benefits under AB 32 is facile. Any such argument ignores the complex relationship between utilities and their regulators.

Discuss Emissions Leakage (July 30, 2012). As a result of detailed negotiations, the Board decided to adopt a policy of freely allocating a certain amount of allowances to industrial entities and electric utilities.

For industry, ARB adopted a schedule of allowance allocations designed to preferentially compensate emissions-intensive industries that are exposed to interstate trade.[119] The allowance distribution is based on a calculated baseline emissions factor multiplied by a predetermined decline in annual free allowances, adjusted by an industry assistance factor.[120] Because the industry allowance allocation incorporates a baseline emissions factor for each industry, it is targeted to address each industry's leakage risks while rewarding individual participants who are more efficient than their competitors. ARB also specified an emissions allocations schedule for electric utilities. The process begins with an allocation of a fixed quantity of allowances to the entire utility sector.[121] The allocation begins with 97.7 mmtCO2 worth of allowances, discounted by a declining annual factor.[122] Once the annual cap has been determined, each utility gets a pre-determined share of the sector-wide allocation, with shares varying by utility and by year.[123]

In total, the allocation to utilities over 2013 through 2020 is 716 mmtCO2.[124] At the most recent auction settlement price of $14.00 per metric ton[125]; this is equivalent to a transfer of over $10 billion in property rights to utility stakeholders. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it addresses allocation to utilities; therefore no response is required.

E-3.36. Comment: 2.2.2 The Decision to Provide Free Allocations to Electric Utilities Increases the Risk of Leakage, Unless ARB Also Adopts a Strong Definition of Resource Shuffling. As a tool to reduce leakage, free allocation makes most sense in the context of covered entities in the industrial sector, which could potentially shut down, relocate, or lose out as their competitors in uncovered jurisdictions expand. This would be a textbook example of leakage, and thus, the free allocation process for industry—which preferentially compensates those industries above other covered entities—is reasonably related to the legal requirement to minimize leakage.[126]
Outside of the case of industrial entities, however, there is very little risk that the carbon price signal would cause utility customers to leave the state. The cost of purchasing electricity and natural gas is a small part of residential and commercial consumers'

119 Cal. Code Regs., tit. 17, § 95870(e), Table 8-1 (categorizing industries by leakage risk and specifying a corresponding "Industry Assistance Factor").
120 Id. § 95891.
121 Id. § 95870(d).
122 Id. § 95891, Table 9-2.
123 Id. § 95892, Table 9-3.
124 Calculated by multiplying the initial utility sector allocation of 97.7 mmtCO2e by the annual cap adjustment factors, and summing each product for each year 2013 through 2020. See id. §§ 95891-2.
125 California Air Resources Board, Quarterly Auction 3 Summary Results Report (June 5, 2013 update), available at http://www.arb.ca.gov/cc/capandtrade/auction/may-2013/updated_may_results.pdf. The settlement price for 2013 vintage allowances was $14.00.
126 We do not comment on the desirability of this policy decision—we merely note that it plausibly relates to addressing a possible source of leakage.

overall budgets, so these customers are unlikely to leave the state in response to modest price increases arising from the carbon market. This is not to say that utility customers are indifferent to rising prices. Instead, free allocations to electric utilities should be seen as part of the political process of generating compromise on climate policy and balancing costs between affected parties. Accordingly, ARB requires that utilities apply the value of free allocations "exclusively for the benefit of retail ratepayers . . . consistent with the goals of AB 32."[127]

Because there is no significant risk of leakage from residential and commercial electricity users, ARB's policy to give free allocations to utilities cannot be justified as a mechanism to minimize leakage. Instead, that decision remains subject to the statutory requirement to minimize leakage, as ARB recognized in its final rulemaking for the carbon market in September 2012. Therefore, the interactions between the free allowance schedule for utilities and other aspects of the cap-and-trade regulations must result in the lowest feasible amount of expected leakage.

Unfortunately, recent ARB documents provide clear and compelling incentives to increase leakage from the electricity sector. We document our concerns with the current policy trajectory in more detail in Sections 3 and 4; although the issues we identify are problematic enough in isolation, they must also be understood in the context of the incentives ARB has already provided to covered entities via free allowances.

ARB's predetermined schedule of free allowances amplifies the incentive to resource shuffle above and beyond the general incentive to do so under any state-based climate policy. For example, if a utility successfully divests from a coal power interest without shutting down the underlying facility, that utility will reduce its compliance obligations—despite the obvious leakage that results—and its customers will enjoy the benefits of an allocations schedule that was determined on the basis of legacy coal emissions. Any opportunity to shed compliance obligations under a weak definition of resource shuffling creates an undue windfall for electric utilities' customers: one that will come at the expense of the economic, environmental, and legal integrity of the market.

Fundamentally, any regulation that weakens the original prohibition on resource shuffling is inconsistent with the allocation schedule ARB finalized for utilities. As ARB staff publicly explained, the primary metric for determining a utility's allowance schedule is its expected compliance costs under AB 32.[128] ARB staff carefully calculated expected compliance costs based on utility projections, assigning initial allocations sufficient to fully compensate each utility for these costs.[129]

Although ARB considered two additional incentives for energy efficiency and early compliance actions, the compliance cost compensation accounted for 94% of the

127 Id. § 95892(d)(3). See also California Public Utilities Commission, supra note 22.
128 California Air Resources Board, Appendix A: Staff Proposal for Allocating Allowances to the Electric Sector (July 2011), available at: http://www.arb.ca.gov/cc/capandtrade/allowanceallocation/allowanceallocation.htm.
129 Id. at 5 ("Under this proposal, the complete annual expected cost burden for each utility is initially allocated.").

allocation schedule.[130] This allocation method makes sense only in the context of a strong rule prohibiting resource shuffling. Any rule that permits utilities to divest from their highest emitting resources without concern for leakage is completely inconsistent with the allocation schedule for utilities.

For these reasons, ARB must adopt a strong definition for resource shuffling that prohibits all reasonably anticipated forms of leakage from covered entities. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it addresses allocation to utilities; therefore no response is required. The commenter states that “the decision to provide free allocations to electric utilities increases the risk of leakage, unless ARB also adopts a strong definition of resource shuffling.” ARB staff disagrees that the definition of resource shuffling is not strong enough to prevent resource shuffling. Since the comments related to allocation to utilities are outside the scope of this rulemaking no response is required to the comments dealing with that topic.

Other State Policies and Resource Shuffling

E-3.37. Comment: 2.3 Other State Electricity Policies Create or Enable Perverse Incentives to Engage in Resource Shuffling. In addition to evaluating the interaction between the definition of resource shuffling and the allowance allocation schedule, ARB must also pay close attention to the interaction with existing policies in the electricity sector. Crucially, California’s emissions performance standard (EPS - known as SB 1368) permits California utilities to divest their ownership interests in non-compliant (i.e., coal-fired) facilities, even when that permission conflicts with the statutory requirement to minimize leakage. In retrospect, this is not surprising: SB 1368 was designed to prohibit California utilities from making new investments in proposed coal power plants, not to prevent leakage of greenhouse gas emissions. As a result, compliance with SB 1368 does not demonstrate compliance with AB 32’s requirement that ARB’s regulations minimize leakage.

Similarly, the State’s Renewable Portfolio Standard (“RPS”) encourages the increased production of renewable electricity without concern for the attendant leakage risks. Unlike SB 1368, which prohibits certain kinds of new investments, the RPS places an affirmative requirement on utilities to increase their investment in renewable energy. As with SB 1368, however, the purpose of the policy is not entirely consistent with the goals of AB 32. Quite the opposite: blanket permission to replace fossil fuel resources with renewable energy that qualifies under the RPS would constitute a textbook case of facility swapping, one of the types of resource shuffling ARB has previously identified. As a result, compliance with the RPS does not demonstrate compliance with AB 32’s requirement that ARB’s regulations minimize leakage.

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[130] Id. (“Under this proposal nearly 94% of allowances are allocated to defray expected costs.”). In addition, we note that the methodology ARB employed is almost identical to our own estimations in Section 4, with both sets of calculations relying on utilities’ submissions of Form S-2 to the California Energy Commission. Id. at 3; id. at 5, note 10.

In both cases, ARB needs to anticipate the economic incentives and legal requirements created by the overlapping policy structures in its formal definition of resource shuffling. As we discuss in Section 3, utilities can use compliance with either SB 1368 or the RPS to actively pursue activities that constitute resource shuffling. Thus, ARB's regulations should anticipate and resolve these risks. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Regulation. The resource shuffling provisions in the Cap-and-Trade Regulation are designed to work in concert with other state electricity and greenhouse gas pollution reduction policies, programs, laws, and regulations. The resource shuffling provisions in this regulation cannot hinder entities from meeting obligations in other programs.
>
> Federal regulations to control regional haze by reducing criteria pollutant emissions from coal power plants work together with California's Cap-and-Trade program and EPS rules in their effect on coal power plants.

FERC, CFTC, and Resource Shuffling

E-3.38. Comment: 2.4 ARB Must Be Careful to Avoid Conflict with Federal Authority. In addition to satisfying the legal requirements of AB 32, ARB must also pay close attention to the boundary between state and federal authority. In particular, ARB must be careful to ensure that its regulations do not conflict with the enabling statutes of the Federal Energy Regulatory Commission ("FERC") and the Commodities Futures Trading Commission ("CFTC").

2.4.1 The Federal Energy Regulatory Commission.
We begin by analyzing the relationship between ARB's cap-and-trade regulation and the Federal Power Act. The Federal Power Act provides that FERC shall have jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce." 16 U.S.C. § 824(b)(1). The Act did not displace all state regulation of electric energy systems, however, and extends FERC's authority "only to those matters which are not subject to regulation by the States." Id. § 824(a). Nevertheless, the Supreme Court has described the language reserving unspecified powers as a "mere policy declaration" that "cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose." New York v. FERC, 535 U.S. 1, 22 (2002) (quotations omitted). Thus, an argument that Section 824(a) reserves to the states any aspect of federal power that can be justified under Section 824(b) will fail.

The judicial standard for determining whether a federal law preempts a state law or regulation depends on the nature of the challenge. When a state law or regulation is allegedly in conflict with federal power, courts generally start with the "assumption that the historic police powers of the States were not to be superseded . . . unless that was the clear and manifest purpose of Congress." Id. at 17-28 (quotations omitted). In contrast, when a federal agency acts to preempt state law, the inquiry does include a presumption against preemption, though a reviewing court must nevertheless establish that the agency is "acting within the scope of its congressionally delegated authority." Id. at 18 (quotations omitted).

For example, in New York, the Supreme Court ruled that FERC Order 888 was promulgated under FERC's explicit authority to regulate "transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce." Id. at 18-19 (citing 16 U.S.C. § 824(b)). Specifically, the Court held that FERC has clear statutory authority to assert jurisdiction over two separate activities: (1) trans- mitting electric energy in interstate commerce, and (2) selling wholesale electric energy in interstate commerce. Id. at 19-20. While FERC's authority to regulate electric sales is limited to wholesale transactions, its authority to regulate transmission of electric energy is not. Id. at 20; see also 16 U.S.C. § 824(d) (defining "wholesale" as the "sale of electric energy to any person for resale"). As a result, the Court found that Order 888 fell under the explicit authority Congress granted to FERC in Section 824(b), and was thus a valid exercise of federal authority.

Although New York upholds FERC's authority to regulate interstate transmission of electric power, it should not be read to indicate that any state law impacting interstate transmission of electric power is necessarily preempted. A reviewing court will likely consider the purpose, nature, and effect of a state law that allegedly conflicts with FERC's authority. In the case of resource shuffling regulations under AB 32, any judicial review of a future challenge is likely to turn on the scope, specificity, and rationale behind ARB's policy structure.

2.4.2 Clear, Mechanistic Rules that Operate in Harmony with FERC's Authority Under the Federal Power Act Will Reduce the Risk of Litigation Over ARB's Resource Shuffling Regulations.

As discussed above, the judicial standard that would apply to any future preemption challenge to ARB's rules on resource shuffling will depend on how the court constructs the facts of the case, as well as any relevant federal agency's opinion.[131] To the extent a court views ARB's regulations as conflicting with FERC's, or infringing upon FERC's clear authority to regulate interstate transmission of electric energy, the more likely ARB would be to lose. For this reason, the challenger will seek to show that ARB's rules conflict with FERC's established authority to regulate interstate transmission of electric energy.

In contrast, ARB will need to portray a harmonious relationship between state and federal law; even if a reviewing court were to find some potential for conflict, ARB would want to argue that the conflict does not arise under the scope of FERC's

[131] Of course, if FERC were to issue regulations that it intended to preempt State authority in this area, the legal standard would be significantly more deferential to FERC, which would need only show that these hypothetical regulations fall within its explicit power to regulate interstate transmission of electric energy. See 16 U.S.C. § 824(b).

congressionally delegated authority. Therefore, ARB will want to argue that the Federal Power Act was never intended to preempt state authority to enact reasonable environmental policy. To succeed with this argument, ARB will want to show that its resource shuffling regulations are narrowly designed to achieve a legitimate environmental purpose. The less that its regulatory approach requires it to actively monitor and police complex market transactions—which are the traditional roles of a price regulator, like FERC—the more likely ARB is to succeed with this argument.
As a result, we believe ARB could reduce its preemption risk by reforming its resource shuffling regulations. In its current policy approach, most of which is codified with loose language through informal guidance, ARB risks creating the impression that its enforcement regime could conflict with FERC's authority over interstate transmission of electric energy. One way to mitigate that risk would be to design a regulatory system that operates mechanistically, with clear, objective liabilities and exemptions. If challenged, ARB could then more readily demonstrate that its regulatory system is narrowly designed to manage the environmental attributes of the electricity industry, with only incidental impacts on interstate transmission of electricity or wholesale power markets. In turn, this position would enable ARB to more confidently assert its authority as a compliment, rather than a potentially conflicting parallel, to FERC's jurisdiction.
With this motivation in mind, the reforms we propose in Section 5 are designed to provide a clear rule structure that requires minimal oversight from ARB. By carefully and explicitly defining covered entities' liabilities and compliance options, the rule structure would reduce the need for ARB to remain actively involved in market oversight. In turn, ARB's reduced involvement in the interpretation of the regulatory structure would lower the litigation risk from a preemption challenge.

2.4.3 The Commodities Futures Trading Commission. While the potential for conflicting with federal laws is most apparent in the context of FERC's authority over interstate transmission of electric power, a recent case highlights the need for ARB to consider the CFTC's jurisdiction as well. See Hunter v. FERC, 711 F.3d 155 (D.C. Cir. 2013).

In Hunter, the D.C. Circuit concluded that FERC lacked jurisdiction to conduct enforcement actions in the financial market for natural gas contracts. Id. at 156. Although the Energy Policy Act of 2005 provided FERC with the authority to regulate deception either directly or indirectly affecting natural gas ratepayers, the court concluded that the Commodity Exchange Act's language prohibited FERC from asserting authority that Congress exclusively vested in the CFTC. Specifically, the court noted that Congress gave the CFTC "exclusive jurisdiction . . . with respect to accounts, agreements[,] . . . and transactions involving contracts of sale of a commodity for future delivery, traded or executed" on a CFTC-regulated exchange. Id. at 158 (quoting 15 U.S.C. § 717t-2(c)). Because the subsequent authority provided to FERC in the Energy Policy Act of 2005 explicitly did not repeal or modify the CFTC's existing authority, the court found that FERC lacked the authority to regulate financial market activities, even though financial market activities had a direct impact on the manipulation of physical market activities that are appropriately within FERC's jurisdiction.

Although Hunter directly addressed FERC's authority to regulate natural gas markets, it has the potential to affect FERC's electricity market authority, too. Extending the reasoning in Hunter suggests that a reviewing court might take a similar position with respect to FERC's ability to regulate financial markets in the electricity industry. On the other hand, electricity markets are more complex than natural gas markets, as the distinction between physical and financial markets is simpler in the natural gas industry. In contrast, key electricity markets—such as financial transmission rights, or the real time and day-ahead markets operated by Regional Transmission Operators and Independent System Operators—involve a mixture of physical and financial attributes.[132] Nevertheless, if the ruling in Hunter were subsequently applied to FERC's authority in the context of electricity markets, ARB would need to be careful to harmonize its regulations with respect to the CFTC's jurisdiction. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it addresses federal and state regulatory authority and not specific amendments to the Regulation; therefore no response is required. ARB staff continues to work closely with FERC and with CFTC to ensure that the Cap-and-Trade Regulation harmonizes with these agencies' regulatory authority.

Proposed Alternate Regulatory Approaches

E-3.39. Comment: Although we are critical of the current policy approach, we recognize that ARB faces a difficult task in its upcoming rulemaking. To contribute constructively to the discussion, we offer a fully developed proposal for the upcoming regulation that, in our opinion, embraces multiple stakeholder goals while addressing the concerns we raise here. The proposed rule would:

- Specify the elements of resource shuffling the State must prove in an enforcement action, providing clarity to regulated entities and regulators alike;
- Explicitly retain regulators' ability to bring enforcement actions despite the presence of a safe harbor under extremely limited circumstances in which a regulated entity knowingly exploits a safe harbor to construct trades that game the basic prohibition;
- Close the broadest loopholes, including the safe harbors that would exempt divestment of legacy coal assets from the ban on resource shuffling; and,
- Establish a "reverse offset" option, through which any party may elect to retain the emissions liability in any transaction while divesting from the other attributes of the underlying contract. In return, the electing party would be deemed not to have engaged in resource shuffling.

We describe each element of the proposed rule in detail, but want to highlight the reverse offset here because it is a new concept that potentially resolves the tension between the goals of minimizing leakage and encouraging divestment from coal.

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[132] See Patrick Dougherty, Vincenzo Franco, and David Yaffe, D.C. Circuit Holds CFTC has Exclusive Jurisdiction Over Natural Gas Futures Contracts, Finds FERC Lacked Authority to Impose $30 Million Civil Penalty. Van Ness Feldman, LLP News Alert (March 18, 2013), available at http://www.vnf.com/news-alerts-818.html.

Elsewhere, ARB has taken a conservative view of carbon offsets, requiring exacting standards for projects or protocols that seek to generate credits for reductions taken outside of AB 32 that regulated entities could use to comply with their legal obligations under AB 32. We believe this conservative approach is the correct way to allow for offsets, and argue that the same approach should be adopted here.

In simplest terms, a weak rule on resource shuffling permits a regulated entity to selectively trade its high-emitting resources for low-emitting resources available on the Western interconnect. From an economic perspective, this looks very much like a near-zero price offset option that ignores additionality. With minimal transaction costs under the current regulatory guidance, parties can re-arrange their contract or ownership interests, reporting reduced emissions—yet actual emissions do not change, as the underlying power plants continue to operate as if nothing had changed. There can be no doubt that ARB would reject a carbon offset protocol with these features; we suggest there is no reason ARB should approach resource shuffling with a lower level of concern.

As a means of addressing this weakness, we propose a mechanism that we call a "reverse offset" because its economic logic mirrors that of a conventional offset. In a conventional offset, covered entities pay entities outside of the AB 32 cap for emissions reductions that occur outside of the system but are counted for compliance within the system. Under the reverse offset, entities within the AB 32 system transfer ownership interests in an electricity contract or power plant to an entity outside of AB 32, but retain the liability for emissions from that contract or facility. Conceptually, the emissions accounting at the state border is reversed: in a conventional offset, in-state entities pay to earn credit for imported emissions reductions; in a reverse offset, in-state entities pay to export emissions liability to unregulated parties.

In economic terms, the reverse offset corrects for the leakage that would otherwise arise in the transaction, pricing the avoided leakage at a market rates. This provision guarantees the environmental integrity of the carbon market and provides the most accurate price signal for compliance costs: the cost of obtaining the needed allowances on the open market. It also preserves the option of divesting away from legacy coal assets. Admittedly, it raises the cost of divestment, but again, it does so by pricing the externality at exactly the market price of the California system. Moreover, because utility stakeholders have already been fully compensated for these expected costs through the allocations process, it is a fair and reasonable burden to bear.

Finally, we believe our suggested reforms streamline the regulatory structure for resource shuffling, reducing the likelihood that a reviewing court would strike the policy down on preemption grounds. By narrowly tailoring a clear set of rules that can be applied mechanistically, ARB would act to mitigate any challenger's perception that the resource shuffling rules conflict with federal authority to regulate electricity markets. (CULLENWARD 1)

Response: The commenter offers an alternate regulatory approach to the proposal for resource shuffling set forth by ARB staff, which is very different to the approach in the proposed amendments. The approach included in the 45-day amendments represents the culmination of a multi-year and multi-agency public process that balances minimizing leakage, preventing harm to western electricity markets, and working in harmony with other parts of California's GHG emissions reductions laws, regulations, and policies. The commenters' proposed regulatory approach, which has not been the subject of a public process, cannot be substituted for our fully developed and vetted approach. Instead, it represents only a single, or limited, point of view. ARB staff believes that the proposed alternative regulatory approach would confuse market participants and jeopardize the reliability of markets and the public process.

E-3.40. Comment: My co-author David Weiskopf and I also provide a fully developed alternative regulatory structure that implements a new, market-based mechanism. Our proposal would greatly reduce the potential for leakage related to resource shuffling while permitting covered entities to engage in a range of transactions that would have been impossible under the existing regulations. Of course, additional refinements with input from key stakeholders would only improve the approach we describe; the point is that it is both feasible and desirable for the Board to investigate a different approach to resource shuffling in order to minimize leakage.

5. We appreciate that ARB faces a difficult task in designing a prohibition on resource shuffling that minimizes leakage, creates market certainty, works in harmony with existing state energy policies, and treats in-state and out-of-state electricity providers equally.

Although this is a tall order, we believe it is possible and offer a fully developed proposal that strikes a different balance. Our proposed solution can be found in the appendices to this report. Appendix I presents a draft regulatory text that is compared against the current text of the Staff Guidance document, showing the deletions and additions we propose. We also present our proposed regulatory text in its original form in Appendix II.[133] Notably, our proposal focuses on minimizing leakage, but also provides a number of provisions to increase market certainty and compliance flexibility for covered entities. Our reforms fall into three categories:

- **Clarifying the logic of the compliance regime.** Whatever one believes about the appropriate mix of safe harbors, the basic structure of the regulatory system for resource shuffling is unclear. We expand upon the elements of compliance and enforcement, specifying under which conditions covered entities may safely rely on safe harbor provisions to avoid liability. By providing specific requirements for each element, our proposal increases regulatory certainty.

[133] Although our proposal is written to expand upon the definition of resource shuffling in Cal. Code Regs., tit. 17, § 95802(a)(252), it is easily adapted to the formatting ARB proposed in its July 2013 draft regulations. Specifically, our Section A could remain with the main definition in §95802(a)(252), while our Sections B through D could be moved to the location where ARB has placed its safe harbor language, § 95852(b)(2).

- **Closing overbroad safe harbors.** Based on the concerns expressed in Section 3, we eliminate the broadest safe harbors. Additional closures are possible due to the compliance flexibility options we introduce.
- **Increasing compliance flexibility.** A strong prohibition on resource shuffling creates the possibility of a legal catch-22, in which a covered entity is required to do something that is also prohibited as resource shuffling. We introduce a flexible compliance mechanism that allows covered entities to elect to remain responsible for any leakage. This option allows us to close some of the more complex safe harbors that address conflicts between AB 32 and other state energy policies, especially those related to coal power.

We evaluate how our proposal achieves each of these goals in the next sub-sections. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Regulation. The commenters' proposed regulatory approach, which has not been the subject of a public process, cannot be substituted for ARB staff's fully developed and vetted approach. Instead, it represents only a single, or limited, point of view. ARB staff believes that the proposed alternative regulatory approach would confuse market participants and jeopardize the reliability of markets and the public process.

E-3.41. Comment: 5.1 Section (A) Clarifies the Compliance Regime. [*The commenter's section A below is from the working paper Appendix II.*]

A. General definition

"Resource shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.

(i) A plan, scheme, or artifice may consist of either (1) a single transaction, or (2) an integrated series of transactions that are reasonably related to a covered entity receiving credit based on emissions reductions that have not occurred.

(ii) For the purpose of establishing liability under this definition, an integrated series of transactions does not include any transaction that is necessitated by a safety concern or emergency condition, unless an entity that is party to the integrated series of transactions intended to create, manipulate, or exploit the safety concern or emergency condition as part of a plan, scheme, or artifice to receive credit for emissions reductions that have not occurred.

(iii) Any integrated series of transactions that includes an activity that qualifies as a safe harbor under subsection (B) below does not constitute resource shuffling, unless either of the following conditions hold:

   a. The purported safe harbor activity is not reasonably related to any otherwise valid purpose of the other activities in the integrated series of transactions. In order to establish the existence of resource shuffling despite the presence of a valid safe harbor, any party brining an enforcement action or other legal claim bears the burden of establishing that the valid safe harbor is not reasonably related to an integrated series of transactions that would independently constitute resource shuffling; or,

b. The integrated series of transactions involves the intentional rearrangement of a transaction that exceeds the leakage threshold specified in subsection (B)(xv) into multiple transactions that qualify for the safe harbor in subsection (B)(xv). In order to satisfy the safe harbor conditions specified in subsection (B)(xv), a party against whom an enforcement action or other legal claim has been brought must establish a valid purpose to the re-arrangement of the larger transaction for which the total leakage exceeds the threshold in subsection (B)(xv). Receiving credit based on emissions reductions that have not occurred is not a valid purpose, nor is any economic benefit that follows from such credit.
c. Without limiting other means of establishing a plan, scheme, or artifice under this section, the plain meaning or reasonably expected effects of (1) a contract or (2) a series of contracts that are part of an integrated series of transactions establishes that the parties to that contract or series of contracts intentionally engaged in a plan to undertake the activities specified therein, and knowingly intended any consequences that a person with relevant subject matter expertise would reasonably expect to follow from those activities. Furthermore, the actions of and evidence related to the mental state of agents who have authority to act on behalf of covered entities will constitute the actions of or evidence related to the mental state of that entity.

[*The commenter's section A below is from the commenter's Appendix I.*]

A. General definition

"Resource shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid.

d. A plan, scheme, or artifice may consist of either (1) a single transaction, or (2) an integrated series of transactions that are reasonably related to a covered entity receiving credit based on emissions reductions that have not occurred.

e. For the purpose of establishing liability under this definition, an integrated series of transactions does not include any transaction that is necessitated by a safety concern or emergency condition, unless an entity that is party to the integrated series of transactions intended to create, manipulate, or exploit the safety concern or emergency condition as part of a plan, scheme, or artifice to receive credit for emissions reductions that have not occurred.

f. Any integrated series of transactions that includes an activity that qualifies as a safe harbor under subsection (B) below does not constitute resource shuffling, unless either of the following conditions hold:

i. The purported safe harbor activity is not reasonably related to any otherwise-valid purpose of the other activities in the integrated series of transactions. In order to establish the existence of resource shuffling despite the presence of a valid safe harbor, any party brining an enforcement action or other legal claim bears the burden of establishing that the valid safe harbor is not reasonably related to an integrated series of transactions that would independently constitute resource shuffling; or,

ii. The integrated series of transactions involves the intentional re-arrangement of a transaction that exceeds the leakage threshold specified in subsection (B)(xv) into multiple transactions that qualify for the safe harbor in subsection (B)(xv). In order to satisfy the safe harbor conditions specified in subsection (B)(xv), a party against whom an enforcement action or other legal claim has been brought must establish a valid purpose to the re-arrangement of the larger transaction for which the total leakage exceeds the threshold in subsection (B)(xv). Receiving credit based on emissions reductions that have not occurred is not a valid purpose, nor is any economic benefit that follows from such credit.

g. Without limiting other means of establishing a plan, scheme, or artifice under this section, the plain meaning or reasonably expected effects of (1) a contract or (2) a series of contracts that are part of an integrated series of transactions establishes that the parties to that contract or series of con- tracts intentionally engaged in a plan to undertake the activities specified therein, and knowingly intended any consequences that a person with relevant subject matter expertise would reasonably expect to follow from those activities. Furthermore, the actions of and evidence related to the mental state of agents who have authority to act on behalf of covered entities will constitute the actions of or evidence related to the mental state of that entity.

Fundamentally, we believe that the relationship between safe harbors and the underlying prohibition on resource shuffling must be clarified. The first element of our proposal is designed to provide this clarity while working with whatever mixture of policy goals ARB ultimately adopts in a revised rulemaking. In addition, the rule structure should encompass the possibility that multiple transactions constitute a pattern of resource shuffling. Section (A) of our proposal implements these goals:

- Section (A)(i). We begin by expanding the definition of a “plan, scheme, or artifice” to encompass either single or multiple transactions, which we call an “integrated series of transactions.” In order to be considered part of an integrated series of transactions, each transactional step must be “reasonably” related to the goal of “receiving credit based on emissions reductions that have not occurred.” Our goal here is to maintain the terminology ARB has already selected in its original regulations, clarifying the scope of the prohibition and providing clear metrics for how stakeholders, regulators, and courts should construct the definition.

- Section (A)(ii). Next, we exempt electricity deliveries due to safety or reliability concerns from being included in any analysis of integrated series of transactions. This provision provides a liability shield to any covered entity that responds to safety or reliability concerns. The only possible liability would occur if the entity “intended to create, manipulate, or exploit” these situations. By including intention as a required element of liability here, the provision provides a broad liability shield that can only be overcome with specific evidence of wrongdoing.

Section (A)(iii). This paragraph is a crucial addition to the text, as it constructs the relationship between the liability shield of the safe harbors and the underlying prohibition on resource shuffling. It also specifies the burden of proof in an enforcement action. The net effect of these construction principles is to provide a reliable means for covered entities to establish and rely upon safe harbors, increasing market certainty and clarifying enforcement authority.

- Section (A)(i). We begin by expanding the definition of a “plan, scheme, or artifice” to encompass either single or multiple transactions, which we call an “integrated series of transactions.” In order to be considered part of an integrated series of transactions, each transactional step must be “reasonably” related to the goal of “receiving credit based on emissions reductions that have not occurred.” Our goal here is to maintain the terminology ARB has already selected in its original regulations, clarifying the scope of the prohibition and providing clear metrics for how stakeholders, regulators, and courts should construct the definition.
- Section (A)(ii). Next, we exempt electricity deliveries due to safety or reliability concerns from being included in any analysis of integrated series of transactions. This provision provides a liability shield to any covered entity that responds to safety or reliability concerns. The only possible liability would occur if the entity “intended to create, manipulate, or exploit” these situations. By including intention as a required element of liability here, the provision provides a broad liability shield that can only be overcome with specific evidence of wrongdoing.

Section (A)(iii). This paragraph is a crucial addition to the text, as it constructs the relationship between the liability shield of the safe harbors and the underlying prohibition on resource shuffling. It also specifies the burden of proof in an enforcement action. The net effect of these construction principles is to provide a reliable means for covered entities to establish and rely upon safe harbors, increasing market certainty and clarifying enforcement authority. (CULLENWARD 1)

Response: The commenter lays out a proposed alternative approach to resource shuffling and does not comment directly on ARB staff’s approach in the proposed amendments. The commenter's proposed regulatory approach, which has not been the subject of a public process, cannot be substituted for our fully developed and vetted approach. Instead, it represents only a single point of view. ARB staff believes that the proposed alternative would confuse market participants and jeopardize the reliability of markets and the public process. One example of this confusion is the attempt to include "a series of integrated transactions" as part of the resource shuffling definition. ARB staff believes that this undefined phrase alone would cause great uncertainty in the market place.

ARB staff believes that the relationship between the definition, underlying prohibition, and safe harbors is clear. Activity that meets the definition of resource shuffling and does not fall under a safe harbor is considered resource shuffling.

E-3.42. Comment: "Safe harbor" activities that are not resource shuffling. 5.2 Section (B) Closes the Broadest Safe Harbors. [*The commenter's section B below is from the commenter's Appendix II.*]

(B) The following transaction types shall not constitute resource shuffling as defined by Section 95802(a)(250):

(i) Electricity deliveries made for the purpose of compliance with requirements related to maintaining reliable grid operations, such as North American Electric Reliability Corporation (NERC) Reliability Standards, and Reliability Coordinator directives, including the provision of electricity between balancing authorities or load-serving entities when required to alleviate emergency grid conditions.

(ii) Electricity deliveries that directly replace those that no longer occur due to the retirement of resources.

(iii) Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months, or resulting from an economic bid or self-schedule that clears the CAISO day-ahead or real-time market, for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under subsections [(B)(iv) through (B)(vi)] below.

(iv) Electricity deliveries that are necessitated by operational emergencies or transmission or distribution constraints, including constraints caused by the inability to obtain or retain transmission rights, transmission curtailments or outages, or emergencies.

(v) Electricity deliveries that are necessitated because a First Deliverer has surplus electricity (more than enough to meet demand) as a result of the First Deliverer being required to take electricity from specific generating units (e.g., electricity contracts with "must-take" or "must-run" provisions).

(vi) Electricity deliveries that are required to make up for transmission losses associated with electricity deliveries in California.

(vii) Transactions in which the net compliance obligations across all transacting parties do not decrease. For the purposes of calculating net compliance obligations, this includes obligations within the California carbon market as well as obligations within other jurisdictions with which the California market has been officially linked. Notwithstanding the provisions of Section (A)(iii), this safe harbor cannot be applied to an integrated series of transactions, unless each related transaction independently qualifies for one or more safe harbors.

(viii) Transactions in which the quantity of emissions that could prospectively qualify as leakage is less than [A MAXIMUM THRESHOLD] [sic].

[*The commenter's section B below is from the commenter's Appendix I*.]

(B)"Safe harbor" activities that are not resource shuffling

~~Effective January 1, 2013, t~~The following ~~substitutions of electricity deliveries from a higher emission resource with electricity deliveries from a lower emission resource~~ transaction types shall not constitute resource shuffling as defined by Section 95802(a)(250):

(i) ~~Electricity deliveries that are caused by the procurement of electricity eli- gible to be counted towards and purchased for Renewable Portfolio Stan- dard (RPS) compliance in California.~~

(ii) ~~Electricity deliveries made for the purpose of compliance with state or federal laws and regulations, including the Emission Performance Stan- dard (EPS) rules established by CEC and the CPUC pursuant to Senate Bill 1368.~~

(iii) Electricity deliveries made for the purpose of compliance with require- ments related to maintaining reliable grid operations, such as North American Electric Reliability Corporation (NERC) Reliability Standards, and Reliability Coordinator directives, including the provision of electric- ity between balancing authorities or load-serving entities when required to alleviate emergency grid conditions.

(iv) ~~Electricity deliveries made for the purpose of compliance with either a ju- dicially approved settlement of litigation or a settlement of a transaction dispute pursuant to the dispute resolution terms and conditions of a con- tract for reasons other than reducing GHG compliance obligations.~~

(v) Electricity deliveries that ~~are necessitated by~~ directly replace those that no longer occur due to the retirement of resources.

(vi) ~~Electricity deliveries that are necessitated by termination of a contract~~

~~or divestiture of resources for reasons other than reducing GHG compliance obligation.~~

(vii) ~~Electricity deliveries that are necessitated by early termination of a con- tract for, or full or partial divestiture of, resources subject to the EPS rules.~~

(viii) ~~Electricity deliveries that are necessitated by expiration of a contract.~~

(ix) ~~Electricity deliveries pursuant to contracts for short term delivery of elec- tricity with terms of no more than 12 months, for either specified or un- specified power, linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electrical Distribution Utility has a contract, or in which a California Electrical Distribution Util- ity has an ownership share, and based on economic decisions including congestion costs but excluding implicit and explicit GHG costs. In evalu- ating these short term deliveries of electricity, ARB will consider the lev- els of past sales and purchases from similar resources of electricity, among other factors, to judge whether the activity is resource shuffling.~~

(x) Short-term transactions and contracts for delivery of electricity with terms of no more than 12 months, or resulting from an economic bid or self- schedule that clears the CAISO day-ahead or real-time market, for either specified or unspecified power, based on economic decisions including implicit and explicit GHG costs and congestion costs, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a con- tract, or in which a California Electricity Distribution Utility has an own- ership share, that is not covered under ~~paragraphs 11, 12 or 13~~ subsections [(B)(xi) through (B)(xiii)] below.

(xi) Electricity deliveries that are necessitated by operational emergencies or transmission or distribution constraints, including constraints caused by the inability to obtain or retain transmission rights, transmission curtail- ments or outages, or emergencies.

(xii) Electricity deliveries that are necessitated because a First Deliverer has surplus electricity (more than enough to meet demand) as a result of the First Deliverer being required to take electricity from specific generating units (e.g., electricity contracts with "must-take" or "must-run" provi- sions.).

(xiii) ~~Deliveries of e~~Electricity deliveries that are required to make up for transmission losses associated with electricity deliveries in California.

(xiv) Transactions in which the net compliance obligations across all transacting parties do not decrease. For the purposes of calculating net compliance ob- ligations, this includes obligations within the California carbon market as well as obligations within other jurisdictions with which the California market has been officially linked. Notwithstanding the provisions of Sec- tion (A)(iii), his safe harbor cannot be applied to an integrated series of transactions, unless each related transaction independently qualifies for one or more safe harbors.

(xv) Transactions in which the quantity of emissions that could prospectively qualify as leakage is less than [**A MAXIMUM THRESHOLD**].

Section (B) of our proposal implements these goals:

- Close the Broadest Safe Harbors:
  - Sections (B)(vi) and (viii). These two safe harbors are so broad that a creative lawyer could fit nearly any transaction could fit through them, completely negating the prohibition on resource shuffling. Their reform (and, we argue, elimination) is a necessary prerequisite to meeting the statutory requirement of minimizing leakage.
  - Sections (ii), (vii), (ix). As Section 4 of this report illustrates, the leakage risk from out-of-state coal power is significant and problematic. We recommend eliminating these provisions, which are no longer necessary in light of Section (D) of our proposal.
  - Sections (B)(i), (iv). These safe harbors appear to anticipate situations in which covered entities potentially face a Catch-22, with a strong ban on resource shuffling preventing an entity from engaging in an activity that another law or judicial settlement compels. We are sympathetic to this argument, but with the introduction of the reverse offset in Section (D), we believe these concerns are no longer as compelling.

In our view, there is no economic reason to justify exempting renewable energy transactions from the resource shuffling concern, as Section (B)(i) could be used to facilitate "cherry picking" or "facility swapping." Similarly, there is no economic reason to justify exempting a settlement from the prohibition on resource shuffling — except for the concern that it would be expensive and time intensive for judges or counterparties to anticipate the resource shuffling consequences. Our reverse offset concept relieves judges and counterparties of this burden, and provides a covered entity with a clear escape mechanism from a settlement that results in re- source shuffling.

- Add New Safe Harbors. Finally, we add two new safe harbor provisions to expand compliance flexibility for covered entities.
  - Section (B)(xiv) [redline version]; Section (B)(vii) [clean version]. This new safe harbor explicitly exempts any transaction in which the net compliance obligation across the transacting parties does not decrease. This provision provides for the future linkage of California's carbon market with other jurisdictions, specifically exempting transactions where the compliance obligation passes from one party to another, but never disappears. To prevent abuse of this exemption, the provision explicitly disallows

application of the safe harbor liability shield in Section (A)(iii) to an integrated series of transactions, unless each transaction independently qualifies for one or more safe harbors. In other words, covered entities cannot use this new safe harbor as a “get out of jail free” card to avoid liability for leakage from related transactions.

- Section (B)(xv) [redline version]; Section (B)(viii) [clean version]. The second new safe harbor sets a maximum leakage threshold, below which any transaction is automatically exempt from the basic definition of resource shuffling. Because we recommend closing a number of overly broad safe harbors, we recognize that some stakeholders may find our proposal to be too burdensome, especially for smaller transactions. As a compromise, we suggest that ARB identify a threshold amount of leakage that constitutes a “minimal” level, consistent with the statutory requirements. Note that we reverse the burden of proof for covered entities relying on this safe harbor, in order to protect against the possibility that a covered entity might translate a single, high-leakage transaction into multiple, low-leakage transactions that each qualify for this safe harbor. Fundamentally, the purpose is to exempt small trades, not to encourage new loopholes. (CULLENWARD 1)

Response: The commenter lays out a proposed alternative approach to resource shuffling that involves keeping some of the Regulation’s proposed safe harbors, getting rid of some of them, and changing others. ARB staff’s approach represents the culmination of a multi-year and multi-agency public process that balances minimizing leakage, preventing harm to western electricity markets, and working in harmony with other California’s GHG emissions reduction laws, regulations, and policies, and with similar laws and policies of other states and the federal government. The commenter’s proposed regulatory approach, which has not been the subject of a public process, cannot be substituted for ARB staff’s fully developed and vetted approach. Instead, it represents only a single, or limited, point of view. ARB staff believes that the proposed alternative regulatory approach would confuse market participants and jeopardize the reliability of markets and the public process.

The commenter states, “there is no economic reason to justify exempting renewable energy transactions from the resource shuffling concern.” Increasing renewable energy through California’s RPS is an important complementary policy goal of the Cap-and-Trade Regulation that will achieve substantial reductions in GHG emissions. Furthermore, the RPS is a technology forcing program that is needed to meet California’s long term GHG emissions reduction goals. It would not be reasonable to deem as resource shuffling electricity deliveries caused by procurement of RPS-eligible electricity, when the RPS is a policy designed primarily to reduce GHG emissions over the long term.

E-3.43. Comment: 5.3 Section (C) Defines Specific Categories of Resource Shuffling. Commenter's proposed regulatory "Section C" from working paper Appendix 2. [*The commenter's section C below is from the commenter's Appendix II.*]

(C) Activities that constitute resource shuffling. The following activities are identified by ARB as resource shuffling:

(i) Substituting relatively lower emission electricity to replace electricity generated at a high emission power plant procured by a First Deliverer under a long-term contract or ownership arrangement, when the power plant does not meet California's Emissions Performance Standard regulations.

(ii) Assigning a long-term contract for high emission electricity specified in subsection (C)(i) to a third party such that the assignment results in a reduction in the net compliance obligations across both parties. For the purposes of calculating net compliance obligations, this includes obligations within the California carbon market as well as obligations with other jurisdictions with which the California market has been officially linked.

(iii) Replacing specified power with deliveries of unspecified power, such that the replacement results in a reduction of a covered entity's compliance ob ligations and when the replacement is not merely incidental to an otherwise economically sound transaction or integrated series of transactions, excluding implicit and explicit greenhouse gas prices.

(iv) Replacing unspecified power with deliveries of specified, low-emitting power, such that the replacement results in a reduction of a covered entity's compliance obligations and when the replacement is not merely incidental to an otherwise economically sound transaction or integrated se ries of transactions, excluding implicit and explicit greenhouse gas prices.

[*The commenter's section C below is from the commenter's Appendix I.*]

B. Activities that constitute resource shuffling

The following ~~two~~ activities are identified by ARB as resource shuffling:

(xvi) Substituting relatively lower emission electricity to replace electricity generated at a high emission power plant procured by a First Deliverer under a long-term contract or ownership arrangement, when the power plant does not meet California's Emissions Performance Standard regulations, ~~and the substitution is made in order to reduces a First Deliverer's compliance obligation~~.

(xvii) Assigning a long-term contract for high emission electricity specified in subsection (C)(i)~~A.5 (1) directly above~~ to a third party such that the assignment results in a reduction in the net compliance obligations across both parties~~, for the purpose of reducing a compliance obligation~~. For the purposes of calculating net compliance obligations, this includes obligations within the California carbon market as well as obligations with other jurisdictions with which the California market has been officially linked.

(xviii) Replacing specified power with deliveries of unspecified power, such that the replacement results in a reduction of a covered entity's compliance obligations and when the replacement is not merely incidental to an other-wise economically sound transaction or integrated series of transactions, excluding implicit and explicit greenhouse gas prices.

(xix) Replacing unspecified power with deliveries of specified, low-emitting power such that the replacement results in a reduction of a covered entity's compliance obligations and when the replacement is not merely incidental to an otherwise economically sound transaction or integrated series of transactions, excluding implicit and explicit greenhouse gas prices.

Section (C) of our proposal implements these goals:

- Section (C)(i). This provision essentially aims to prevent "facility swapping," as defined by ARB in previous workshop documents. We retain it, removing only the condition that the facility swapping be done in order to reduce a compliance obligation. It does not matter what motivated the leakage; even if ARB wished to set a definition that applied only when the transfer was caused by compliance cost considerations, enforcement would be almost impossible. Because the number of facilities that do not meet the Emissions Performance Standard is limited, we believe it is better to set a stricter limit; the small number of facilities that are affected by this rule limits the risks of increased market uncertainty.
- Section (C)(ii). It is not immediately clear that Section (C)(ii) is necessary given the language in Section (C)(i), but we retain the approach put forward by ARB for consistency. As with Section (C)(i), we remove the condition that the facility swapping be done in order to reduce a compliance obligation. We add in language limiting this definition by excluding transfers to parties who face compliance ob- ligations in carbon markets with which the California market has officially been linked.
- Section (C)(iii). This provision affirms the prohibition on "laundering," as de-fined by prior ARB workshop documents. We exclude activities from the defini-tion that are "merely incidental" to "otherwise economically sound transactions," excluding implicit and explicit greenhouse gas prices. This exclusion signals the regulator's intention not limit use of the affirmative definition, without requiring an enforcement action to prove that the offending activity or activities was motivated by avoiding compliance costs. It provides an opportunity for a covered entity to demonstrate that the alleged resource shuffling was part of an economically sound activity and was not the purpose or reasonably intended effect of a broader series of transactions.
- Section (C)(iv). This provision affirms the prohibition on "cherry picking," as defined by prior ARB workshop documents. We adopt the same approach to defining the scope of the affirmative definition as in Section (C)(iii).

Response: The commenter lays out a proposed alternative approach to resource shuffling that involves keeping some of the Regulation's proposed safe harbors, getting rid of some of them, and changing others. ARB staff's approach represents the culmination of a multi-year and multi-agency public process that balances minimizing leakage, preventing harm to western electricity markets, and working in harmony with other California's GHG emissions reduction laws, regulations, and policies, and with similar laws and policies of other states and the federal government. The commenters' proposed regulatory approach, which has not been the subject of a public process, cannot be substituted for our fully developed and vetted approach. Instead, it represents only a single, or limited, point of view. ARB staff believes that the proposed alternative regulatory approach would confuse market participants and jeopardize the reliability of markets and the public process.

The commenter's sections (C)(i) and (C)(ii) are very similar to sections 95852(b)(2)(B)(1) and (2) in the proposed amendments, except that the commenter proposes to remove an important limiting condition. The commenter would remove the condition that the transaction types included in these provisions be done in order to reduce a compliance obligation for the transactions to be included in this category of resource shuffling. ARB staff disagrees. Including the condition of limiting the scope of substitutions that are resource shuffling provides clarity to market participants and is necessary to harmonize the Cap-and-Trade Regulation with California's EPS rules adopted pursuant to SB 1368. A substitution of lower emission electricity for power from an EPS-non-compliant facility may be necessary for reasons included in the safe harbors, such as lack of transmission or retirement of a power plant, or for other reasons not part of a plan, scheme or artifice to reduce a compliance obligation. Such cases would not be considered resource shuffling.

ARB staff will be able to enforce the resource shuffling provisions because we have sufficient data on California EDU's long term entitlements to purchase power from non-EPS-compliant power plants, and will monitor the disposition of this power.

The commenter also proposes adding two additional categories of transactions as constituting resource shuffling. Adding these two additional categories of transactions would cause confusion in the market because the meanings of the phrases "not merely incidental" and "economically sound" are not clear. ARB staff believes that the proposed additions could confuse market participants and jeopardize the reliability of markets and the public process.

E-3.44. Comment: 5.4 Section (D) Increases the Compliance Flexibility.[*The commenter's section D below is from the commenter's Appendix II.*]

(D) Voluntary assumption of leakage. Any covered entity that engages in a transaction or integrated series of transactions that would normally constitute resource shuffling may make an election under this subsection, in which case that transaction or integrated series of transactions will not constitute resource shuffling.

(i) A covered entity making an election under this subsection must notify the Air Resources Board in writing before it undertakes a transaction or integrated series of transactions, specifying the nature of the transaction or integrated series of transactions.

(ii) A covered entity making an election under this subsection will assume the compliance obligations that correspond to the compliance obligations that entity faced before undertaking the affected transaction or integrated series of transactions. After executing the transaction or integrated series of transactions, each affected entity will report its adjusted greenhouse gas emissions as it would if it had not made an election, with one supplemental term: an additional source of greenhouse gas emissions equal to the difference between the greenhouse gas emissions associated with the transfers away from the covered entity and the greenhouse gas emissions associated with transfers to the covered entity, pursuant to the methods established by the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, as set forth in title 17, California Code of Regulations, chapter 1, subchapter 10, article 2 (commencing with section 95100). This supplemental reporting should match the methods and data used in previous reporting affecting the transferred resource, unless subsequent operation of the transferred resource justifies the use of new methods or data.

(iii) A covered entity making an election under this subsection assumes its historical compliance obligation under subsection (D)(ii) until such time as

(1) the resource transferred away from the covered entity retires, or

(2) another covered entity accepts liability for the same resource in the California carbon market, or another with which the California market has been formally linked. At such time, the covered entity that made the original election under this subsection may file a written notice to the Air Resources Board specifying the applicable circumstances. Once a true and accurate filing has been made, the covered entity will no longer be responsible for its historical compliance obligations from that point forward, and may cease to report its historical emissions pursuant to subsection (D)(ii).

[*The commenter's section B below is from the commenter's Appendix II.*]

B. Voluntary assumption of leakage

<u>Any covered entity that engages in a transaction or integrated series of transactions that would normally constitute resource shuffling may make an election un- der this subsection, in which case that transaction or integrated series of transactions will not constitute resource shuffling.</u>

(xx) A covered entity making an election under this subsection must notify the Air Resources Board in writing before it undertakes a transaction or integrated series of transactions, specifying the nature of the transaction or integrated series of transactions.

(xxi) A covered entity making an election under this subsection will assume the compliance obligations that correspond to the compliance obligations that entity faced before undertaking the affected transaction or integrated series of transactions. After executing the transaction or integrated series of transactions, each affected entity will report its adjusted greenhouse gas emissions as it would if it had not made an election, with one supplemental term: an additional source of greenhouse gas emissions equal to the difference between the greenhouse gas emissions associated with the transfers away from the covered entity and the greenhouse gas emissions associated with transfers to the covered entity, pursuant to the methods established by the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, as set forth in title 17, California Code of Regulations, chapter 1, subchapter 10, article 2 (commencing with section 95100). This supplemental reporting should match the methods and data used in previous reporting affecting the transferred resource, unless subsequent operation of the transferred resource justifies the use of new methods or data.

(xxii) A covered entity making an election under this subsection assumes its historical compliance obligation under subsection (D)(ii) until such time as (1) the resource transferred away from the covered entity retires, or (2) another covered entity accepts liability for the same resource in the California carbon market, or another with which the California market has been formally linked. At such time, the covered entity that made the original election under this subsection may file a written notice to the Air Resources Board specifying the applicable circumstances. Once a true and accurate filing has been made, the covered entity will no longer be responsible for its historical compliance obligations from that point forward, and may cease to report its historical emissions pursuant to subsection (D)(ii).

5.4 A better solution would be to provide some sort of flexible option that addresses the leakage caused by parties who have legitimate interests in undertaking activities that would normally constitute resource shuffling, such as the resolution of a dispute or litigation. We propose such an option as Section (D). Section (D) Increases the Compliance Flexibility. This section implements a new market-based compliance option that is designed to expand regulated entities' ability to comply with a strong prohibition on resource shuffling. We call this new instrument a "reverse offset."

The name intentionally reflects a close parallel with traditional offsets. A carbon offset protocol awards credit for emissions reductions that occur outside the scope of a carbon market's jurisdiction. In contrast, a reverse offset retains environmental liability for activities that shift emissions out of the carbon market, without reducing them.

Legally, the reverse offset acts to split the environmental liabilities from the remaining property right attributes of a transaction that would otherwise constitute resource shuffling. A covered entity that elects a reverse offset retains that liability, and is permitted to do as it pleases with the remaining property rights. Because the covered entity retains the emissions liability in any transfer, there is no increase in emissions outside of the state's market, and thus, no leakage. Similarly, there is no reduction in emissions re- porting, and thus, no resource shuffling.

Economically, the reverse offset provides clear and accurate incentives to all covered entities. Because an electing entity retains an environmental liability that it must satisfy with allowances, the reverse offset prices leakage at the market price for allowances. Like an offset, the reverse offset harmonizes the cost of compliance using market forces.

In policy terms, the reverse offset provides a middle ground between strict command-and-control regulation and a retreat from enforcing the prohibition on resource shuffling. By design, the reverse offset accommodates multiple, previously conflicting policy goals.

It allows covered entities to divest from coal, increase renewable energy while exporting legacy fossil fuel-based electricity, and engage in any profitable activity. Its only effect is to price the leakage that would otherwise occur. Environmentally, the reverse offset protects against leakage because it allows ARB to close overbroad safe harbors.

Unlike previous proposals that would have separated the greenhouse emissions liability from all other attributes in electricity contracts,52 the administrative costs of the reverse offset would be more modest. There is no need to track both attributes separately for all contracts—only for those that covered entities elect to separate to avoid resource shuffling. Furthermore, ARB would not have to track the emissions attributes; our proposal would require electing covered entities to report the supplemental emissions, until such time as the underlying facility shuts down or becomes the compliance obligation of another covered entity.

Section (D) of our proposal implements the reverse offset:

- Section (D)(i). A covered entity making an election under this section must notify ARB in writing, specifying the details of the transaction.
- Section (D)(ii). A covered entity making an election under this section agrees to assume continued compliance obligations for the resource that is transferred outside of the coverage of AB 32. The ongoing compliance obligation is defined as the difference between the higher emitting resource that was transferred away and the newer resource that replaced it. Thus, if a utility swapped a coal contract for a gas contract, holding total MWh constant, it would continue to report total compliance obligations equal to the coal emissions levels. As usual, it would

report its regular compliance obligations, equal to the natural gas emissions; in addition, it would report the difference between the old coal emissions and the new natural gas emissions, which brings the total back to the original level of emissions. This section also sets out the data reporting requirements for the new compliance obligations, requiring a consistent estimation or reporting methodology, unless subsequent operation of the generating resource transferred outside of AB 32 justifies new methods or data. This reporting requirement compels the covered entity to report accurate emissions information.

Section (D)(iii). A covered entity making an election under this section assumes its new compliance obligations until one of two terminal conditions. The first terminal condition occurs when the transferred resource retires. The second terminal condition occurs when another entity accepts liability for the transferred resource, either within the California carbon market, or in another market with which the California carbon market has been linked. Essentially, this requires the covered entity making an election under this section to assume continued responsibility for the emissions that would otherwise leak out of AB 32, until such time as the leakage ends - either because the emissions end, or because the liability falls on another party within the capped system. Both conditions represent the end of the potential for leakage, and thus serve as clear bases for terminating the elective liability concept under the reverse offset. (CULLENWARD 1)

Response: ARB staff declines to create a completely new instrument and mechanism the commenter calls a "reverse offset." The proposed resource shuffling amendments are based on a long and complex public process, in which ARB staff was required to balance many exigencies, including providing clear and consistent messages needed for a viable market of compliance instruments. Making major changes contemplated in the commenter's proposed approach would upset the overall regulatory program now in place. This comment recommends that ARB staff adopt a new, untested mechanism. ARB staff believe that its adoption would have strong potential to undermine allowance and electricity markets, and would undermine the public process to date. Therefore ARB staff declines to incorporate this proposed approach.

E-3.45. Comment: In addition to documenting our concerns about the current policy trajectory, we provide a fully developed set of reforms that ARB might consider in an upcoming rulemaking. A subset of these reforms is designed to increase market certainty and improve the enforceability of the safe harbor approach, whatever perspective ARB adopts on the leakage risks we identify. Based on our concerns about leakage, we propose closing a number of safe harbors. Some of the provisions are simply too broad to be included in a robust final rule. Others pose reduced (though still substantial) risks of leakage; they also become unnecessary in light of our suggested reforms.

Our suggested reforms are built around a new "reverse offset" concept, under which covered entities can elect to retain greenhouse gas emissions liability in any transaction that would otherwise constitute resource shuffling. This new option provides additional compliance flexibility, permitting ARB to close safe harbors while still permitting covered entities to engage in a wide variety of market-based transactions. Although the reverse offset option acts to keep compliance costs on covered entities, this outcome is a fair and reasonable burden to bear because utilities that would face costs under our proposed rule structure have already been fully compensated by ARB's existing allowance allocation process.

Although we designed our proposal to address the goal of minimizing leakage under AB 32, we believe that the end result could reduce the risk of litigation over preemption issues. By reducing an opaque set of rules that require significant interpretation into a clear, narrowly focused and mechanistic regulatory text, we anticipate that any reviewing court would be less likely to find grounds on which to preempt ARB's authority. (CULLENWARD 1)

> **Response:** ARB staff's approach properly balances the requirement to minimize leakage with other necessities, including being compatible with existing regulatory and market structures that ensure reliability of the electric system. While staff appreciate the effort of the commenter to develop an alternate approach to address resource shuffling, it is not feasible for ARB staff to replace its balanced approach that is the culmination of a lengthy stakeholder process with a distinct and unvetted approach, including a wholly new concept of "reverse offsets."

California Electricity Consumption

E-3.46. Comment: 1.1 Background on electricity consumption in California. The differences between California's electricity consumption mix and those of neighboring states are crucial factors influencing the design of the state's carbon market. California has a relatively low-carbon electricity grid, relying primarily on natural gas, hydropower, and nuclear energy; renewables like wind and solar are playing an increasingly important role, too (see Figure 1). But the state also imports significant amounts from the Pacific Northwest and Southwest, with imports accounting for 31% of total consumption (see Figure 2).[134]

As these figures illustrate, the generation mix of imported power looks very different from the in-state mix. Notably, a large amount of imported power comes from coal, which has the highest greenhouse gas emissions profile of all resources. In addition, an even larger share of imports comes from unspecified sources. In contrast, California generates only a tiny fraction of its power from coal and has no unspecified in-state power because it has complete information about the mixture of in-state generating resources.

While the greenhouse gas implications of conventional coal power are clear, unspecified power presents a more complicated problem. Consumption of electricity

[134] California Energy Commission, Energy Almanac, Total Electricity System Power, available at http://energyalmanac.ca.gov/electricity/total_system_power.html (2011 data).

from unspecified sources cannot be traced to a particular generation resource, which makes estimating the associated greenhouse gas emissions difficult. One method is to adopt a generic emissions factor that estimates the average emissions intensity of the unspecified power mix. For the California carbon market, ARB selected an emissions intensity factor that resembles that of baseload natural gas emissions.[135] This level is about half of what coal-fired electricity usually generates, which presumably reflects a system in which unspecified power could come from coal, natural gas, or zero-carbon renewable energy.

Due to different electricity mixes across Western states, greenhouse gas emissions from imported power account for 47% of California's total emissions from the electricity sector.[136] As this number makes clear, any effort to reduce emissions from California's electricity consumption must pay careful attention to imported power.

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135 Cal. Code Regs., tit. 17, § 95111(b) (setting an emissions factor for unspecified imports of 0.428 metric tons CO2e per MWh consumed).

136 ARB, California Greenhouse Gas Inventory for 2000-2010, available at http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_00-10_2013-02-19.pdf. Note that ARB uses a different method for calculating unspecified power emissions here, based on a bottom-up analysis of consumption from different regions. See ARB, Detailed 2000-2010 Inventory Tables by IPCC Category, available at http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_ipcc_00-10_all_2013-02-19.pdf. The different methods are justified by the fact that a detailed ex post analysis is possible for an emissions inventory, but cannot be done ex ante to estimate an average statewide emissions factor. This is because the future mixture of imported electricity is always subject to change from market forces.

Figure 1: In-state electricity consumption by generation source, 2011 (GWh).[137]

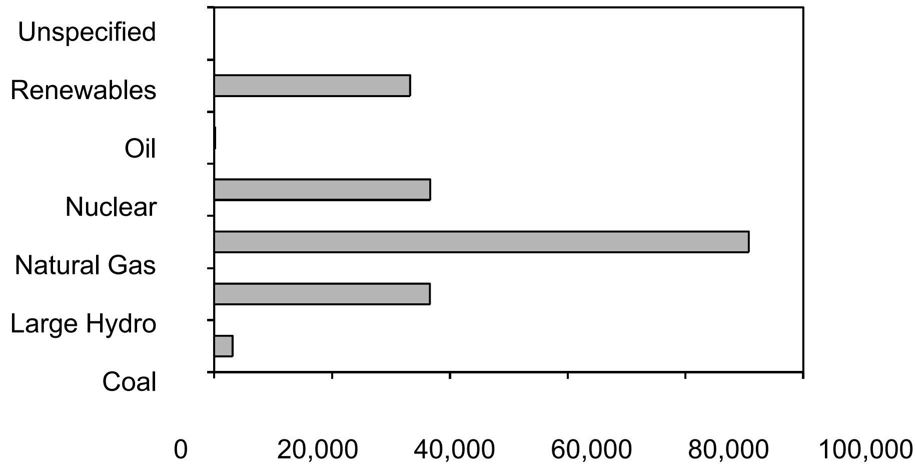
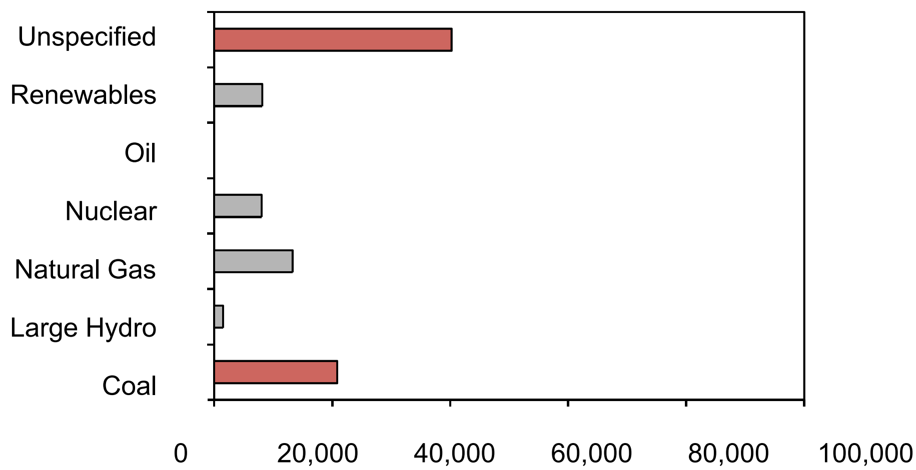


Figure 2: Imported electricity consumption by generation source, 2011 (GWh).[138]



1.2 Unspecified power is the result of complexities in the physical and legal system for managing electricity. Due to the physics of the electricity system, the popular conception that there are "green electrons" and "brown electrons" is misplaced: for grid-connected customers, there simply is no way to precisely identify a kWh of end-use consumption as coming directly from one particular generation resource or another. Instead, emissions must be determined on a more aggregate level (see Figure 3) and/or tracked on the basis of the legal and financial instruments that govern the industry.

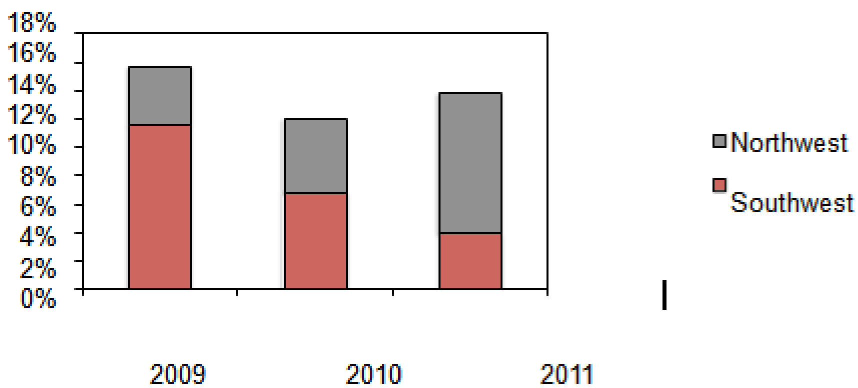
Although this is a difficult problem, it should not be overstated. Indeed, various organized wholesale electricity markets function well - such as the market overseen by the California Independent System Operator - despite the imperfect relationship between financial contracts and the physical nature of the electricity system.

137 California Energy Commission, supra note 3.
138 *Id*.

Nevertheless, the contractual features of organized wholesale market and bilateral electricity transactions were not designed to track the greenhouse gas emissions intensity of participating resources. As a result, the organized market structures and bilateral contracts between generators and buyers do not always provide the information necessary to determine the emissions attributes of a particular contract. This is not to say that the basic contracts are unreliable; only that if a market structure is based around determining clear prices, quantities, and timing - without a corresponding focus on the greenhouse gas emissions intensity of each generator - then the market may not be equipped to provide emissions information at the level of each unit of power sold.

One helpful analogy is to think about this problem like the chain of title for real property in the wake of the recent financial crisis. For example, we may not know the true legal owner of a house is if the underlying property right was transferred into a securitized investment vehicle and subsequently sold to many different investors. In this situation, the only way to confirm the true legal owner is to track the change in legal rights at each step of the transactional history for that property. Similarly, the only way to determine the ultimate generating resource behind a particular delivery of power is to trace the contractual relationships at each step back to the original power plant. But if the contractual relationships are not clear, or the necessary data are not publicly available, then it is impossible to determine the ultimate generating resource with certainty.

Figure 3: Unspecified Imported Electricity by Origin (% of Total Consumption).[139]



139 California Energy Commission, supra note 3. Prior to 2009, the CEC did not track unspecified imports directly. Instead, the CEC inferred them indirectly by reference to the generation profile of the exporting region, from which the CEC subtracted specified power transactions. As a result, data from before 2009 must be inferred by estimation. See, e.g., California Air Resources Board, Documentation of California's Greenhouse Gas Inventory (5th Ed.), available at http://www.arb.ca.gov/cc/inventory/doc/doc_index.php (estimating unspecified power imports and associated emissions for the period 2000-2010).

The issues surrounding unspecified power are particularly important in the context of resource shuffling. Because ARB assigned an emissions factor that resembles baseload natural gas energy, electricity market participants face two incentives. First, any seller of a generation resource that is cleaner than the default emissions factor will have an incentive to take the necessary steps to become a specified source of power. By identifying the lower-carbon nature of the underlying resource, such sellers will reduce the greenhouse gas liability that must be allocated between buyer and seller. Second, any seller of a generation resource that is more carbon-intensive than the default emissions factor will have an incentive to take steps to become an unspecified source of power. By hiding the higher-carbon nature of the underlying resource, such sellers will reduce the greenhouse gas liability that must be allocated between buyer and seller.

From a public policy perspective, the first incentive is a good one, as it will generate more and better market information. In contrast, ARB should be very concerned about the second incentive, which encourages market participants to undermine the fundamental purpose of AB 32. As a result, we believe ARB should anticipate self-interested trading behavior in its resource shuffling regulations. During the discussion of the initial carbon market regulations, ARB appeared to take this position, too. But as we discuss in Sections 3 and 4, ARB's current approach does not provide sufficient protection against this type of leakage. This concern motivates a number of the reforms we offer in Section 5. (CULLENWARD 1)

> **Response:** The comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Regulation. ARB staff agrees that the choice of a default emission factor can provide an economic incentive for a seller of power from an emissions-intensive resource to prefer to sell less emissions-intensive power. ARB staff addresses this incentive through the resource shuffling provisions, the imported electricity provisions including requirements for claiming emission factors of specified sources, and by coordinating Cap-and-Trade provisions with MRR, which requires accurate and verified reporting of emissions associated with electricity generated in, or imported into, California.

Coal Leakage Analysis

E-3.47. Comment: We conclude that the current safe harbors provide almost unlimited exemptions from the prohibition on resource shuffling, raising the possibility of completely unchecked leakage. We also conclude that the safe harbor guidance clearly permits early divestment from out-of-state coal without any apparent concern for leakage.

But the problem is not limited to a few loose words; ARB has also indicated an interest in encouraging divestment from legacy coal power plants, without sufficient concern for the attendant leakage risks. We present the fullest accounting of legacy coal contracts and ownership investments to date, analyzing the leakage implications of allowing

California entities to fully divest from these interests when the underlying facility is not retired.

Our calculations show the cumulative potential for between 108 and 187 million metric tons of carbon dioxide leakage from the cap-and-trade program by 2020, depending on the type of replacement power selected. Depending on the success of complimentary policies and the use of the allowance price containment reserve, the maximum leakage risk is equivalent to between 47% and 197% of cumulative mitigation expected through 2020 under AB 32.[140] Although a comprehensive comparison of leakage risks from resource shuffling is complex and assumption-laden, one clear pattern emerges from our analysis: the more successful California's comprehensive climate policy becomes, the more a lax regulation on resource shuffling will undermine the cap-and-trade program.

While the policy goal of divesting from coal pre-dates AB 32 and has important environmental benefits, we argue that ARB has not accounted for the conflict with its statutory requirement to minimize leakage under AB 32. Given that ARB has already provided free allocations to utilities on the basis of their expected compliance costs—under the assumption that there would be a firm prohibition on resource shuffling—we are skeptical of any policy trajectory that permits utilities to leak their legacy emissions profile through safe harbors. And the problem is huge: ARB freely allocated 716 mmtCO2 to utilities through 2020, worth over $10 billion at current market prices. It is hard to imagine a justification for providing these allowances to compensate utilities (and their ratepayers) for compliance costs they are then permitted to avoid at the expense of the market's integrity. (CULLENWARD 1)

> **Response:** ARB staff disagrees with the commenter that the proposed amendments do not minimize leakage. ARB staff believes that by harmonizing the resource shuffling provisions in this regulation with State policy designed to end, or prevent renewal of, legacy coal contracts, staff achieves the correct balance of minimizing leakage and providing other benefits to California citizens.

E-3.48. Comment: The exemptions for out-of-state coal power contracts are particularly problematic. The proposed amendments unambiguously exempt divestment of these contracts from the prohibition on resource shuffling, without a corresponding requirement that underlying facilities retire or otherwise reduce their emissions. The calculations in the attached Stanford Law School white paper show that the associated leakage risks constitute between 47% and 193% of the cumulative mitigation expected under the cap-and-trade market through 2020, depending on the success of complimentary policies and the use of the allowance price containment reserve.[141]

Simply put, the potential for leakage at this scale threatens to undermine the integrity of the carbon market, and cannot be reconciled with the statutory requirement to minimize leakage.

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[140] See Section 4.1, *infra*.
[141] See Cullenward and Weiskopf, supra note 2, at § 4 for details.

4. Analysis: leakage risk from coal divestment. As the previous section demonstrates, ARB's current policy trajectory clearly permits utilities to divest from out-of-state coal power contracts and ownership interests without violating the prohibition on resource shuffling. In this section, we analyze the associated leakage risks that follow from this permissive structure.

Our analysis finds a potential for leakage from out-of-state coal power of up to 186.9 mmtCO2 between 2013 and 2020, an average of 23.4 mmtCO2 per year over the same period (see Table 1). For comparison, the Electric Power Research Institute ("EPRI") projects that cumulative mitigation over the same period must be between 97 and 395 mmtCO2e, depending on the performance of complimentary policies, the supply of carbon offsets, and the use of the State's allowance price reserve account.[142] As a result, the maximum leakage we identify here accounts for between 47% and 193% of the cumulative, economy-wide mitigation required under AB 32.

To bound our analysis of the leakage risks from a permissive resource shuffling rule, we construct two baseline scenarios that reflect different ways of looking at the requirements of California's Emissions Performance Standard, also known as SB 1368. This statute requires state regulators to set a greenhouse gas emissions performance standard equal to combined cycle natural gas power plant emissions.[143] SB 1368 prohibits utilities from entering into a "long-term financial commitment" with facilities that fail to meet this performance standard.[144] Although utilities cannot enter into long-term financial commitments, new or renewed contracts with terms of less than five years are still permitted.[145]

Table 1: Leakage Potential from Early Divestment, 2013 through 2020 (mmtCO2e).

	Replacement Power	
Scenario	**Zero-Carbon (e.g., renewable)**	**Natural Gas**
Maximum Coal	186.9	107.7
Planned Divestment	127.6	74.1

Our scenarios explore different plausible strategies for compliance with SB 1368. The first, "Maximum Coal Scenario," represents a future in which all current and projected procurements from coal power continue indefinitely. This scenario represents a situation in which utilities exploit the potential to continue to make short-term contracts with non-compliant facilities beyond their current contract terms. The second, "Planned

142 Electric Power Research Institute, Exploring the Interaction Between California's Greenhouse Gas Emissions Cap-and-Trade Program and Complimentary Emissions Reductions Policies, EPRI Report #3002000298 (March, 2013), available at http://www.epri.com.

143 Cal. Pub. Utilities Code § 8341(d)-(e).

144 Id. § 8341(a).

145 Id. § 8340(f) (defining long-term financial commitment as a "new ownership investment . . . or a new or renewed contract with a term of five or more years").

Divestment Scenario," assumes that utilities will divest from coal power contracts (but not ownership interests) at the end of current contract terms. Although the first scenario best approximates the leakage implications of resource shuffling, we address the second scenario because it arguably represents the political consensus reached under SB 1368, which effectively precludes new long term interests in coal power, and sunsets existing interests— although again, nothing in SB 1368 precludes repeated, short-term extension of existing contracts.

Against each baseline, we calculate the leakage potential if coal power is replaced with zero-carbon energy (e.g., renewables) and natural gas baseload emissions (e.g., natural gas combined cycle, also equivalent to the default emissions level for unspecified power). Covered entities that are permitted to resource shuffle will preferentially substitute any available zero-carbon replacement resources, but may be limited by supply. Our two replacement power options fully bound the potential leakage. Summary results are provided in Table 1, and we discuss the full methodology in Appendix III. As these calculations demonstrate, the potential for leakage from legacy coal power contracts is quite large. If ARB's regulations on resource shuffling permit utilities to divest from these contracts without ensuring the underlying facilities shut down, this decision will result in as much as 187 mmtCO2 leaking out of AB 32. (CULLENWARD 1)

> **Response:** Under the proposed amendments, utilities may fully divest of, or shed ownership interests in, contracts with non-EPS-compliant power plants without violating resource shuffling prohibitions. ARB staff believes that by harmonizing the resource shuffling provisions in this regulation with State policy designed to end, or prevent renewal of, legacy coal contracts, staff achieves the correct balance of minimizing leakage and providing other benefits to California citizens. Further, this comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Regulation.
>
> Nonetheless, ARB staff believes that the analysis is flawed. The analysis is based on the assumption that the power plants in question will continue to emit as they have in the past, and the compliance responsibility for all of their emissions will be avoided through resource shuffling. This is not a plausible scenario.
>
> Furthermore, ARB staff believes the specific prohibitions in section 95852(b)(2)(B) will preclude California utilities from resource shuffling. Instead, they are already working with ARB staff to ensure that any steps they take toward divestment are not resource shuffling. In addition, USEPA regulations that tighten criteria pollutant emissions requirements for existing coal plants, and lower natural gas prices that make coal power less economically attractive make it more difficult for California utilities to divest and sell their interest in coal plants to other parties rather than retire the units or facilities. Finally, the USEPA has begun the public process to regulate emissions from new and existing power

plants under sections 111(b) and 111(d) of the Clean Air Act. While the content of the final regulations is not yet known, they cause uncertainty in the market for high emission power plant contracting or ownership. This uncertainty will make it far less likely for entities to take emissions responsibility for non-EPS-compliant power plants that currently supply California utilities, forcing California utilities to either retire the facilities, or continue operating them for their own customers, and thereby taking responsibility for the compliance obligation associated with importing the power.

E-3.49. Comment: Furthermore, the safe harbors clearly exempt early divestment from out-of-state coal power contracts from the prohibition on resource shuffling. We present the most detailed analysis of the leakage that would result from this policy decision, estimating leakage risks of up to 187 mmt CO2 through 2020. Compared against expected cumulative mitigation efforts in the cap-and-trade market, this leakage risk accounts for between 47% and 193% of total compliance required under AB 32. Leakage from the broadest safe harbors could be even higher. (CULLENWARD 1)

Response: The safe harbors intentionally exempt early divestment from out-of-state coal power contracts to harmonize this regulation with the requirements and goals of California's EPS law and regulations ARB staff believes that by harmonizing the resource shuffling provisions in this regulation with State policy designed to end, or prevent renewal of, legacy coal contracts, ARB achieves the correct balance of minimizing leakage and providing other benefits to California citizens. It is not reasonable to assume that out-of-state power plants will continue to emit as they have in the past.

E-3.50. Comment: 4.1 Comparing Resource Shuffling Leakage Risks to Cumulative Mitigation Expected Under AB 32. The magnitude of the impacts we identify warrants further explanation and comparison with the cumulative mitigation efforts required under AB 32.

As a threshold matter, it is important to understand that the cap-and-trade targets under AB 32 are expressed in terms of annual emissions levels, not cumulative mitigation requirements. For example, ARB projects that total reductions from the cap-and-trade program must be 22 mmtCO2e per year below expected business-as-usual emissions in 2020.[146] Translating these annual targets into cumulative mitigation targets requires assumptions about the performance of AB 32 market features, such as the availability of carbon offsets and the use of the allowance price containment reserve ("APCR"), as well as so-called complimentary policies, such as the Low Carbon Fuel Standard or Renewable Portfolio Standard (see Table 2).

[146] See Table 1.2-3 in California Air Resources Board, Final Supplement to the AB 32 Scoping Plan Functional Equivalent Document (Aug. 19, 2011), available at http://www.arb.ca.gov/cc/scopingplan/document/final_supplement_to_sp_fed.pdf.

Table 2: Cumulative Mitigation Expected Through 2020, Assuming Maximum Use of Carbon Offsets (mmtCO2e).[147]

Mitigation from Complimentary Policies	Allowance Price Containment Reserve	
	Fully Used	Not Used
As Expected	97.0	219.0
Zero Effect	273.2	395.0

Assuming that complimentary policies meet their targets and that the APCR is fully exhausted, the Electric Power Research Institute estimates that cumulative abatement through 2020 will total 97.0 mmtCO2e. As a result, the maximum potential for leakage we estimate here is 192% of the cumulative mitigation expected under the best-case scenario for AB 32 implementation.

If ARB continues its permissive approach to resource shuffling, however, it is un likely that the APCR will be fully exploited. Allowances placed in the APCR are avail- able only if carbon market prices rise quickly; but if utilities can use resource shuffling to avoid compliance obligations, it is likely that prices will remain below the APCR threshold. In this situation, again assuming complementary policies meet their target, EPRI estimates that cumulative mitigation through 2020 will be 219.0 mmtCO2e. As a result, the maximum potential for leakage we estimate here is 85% of the cumulative mitigation expected under this scenario.

It is also possible that the mitigation expected under complimentary policies falls short, due to legal challenges, ineffective policy implementation, or other unforeseen problems. To estimate the worst-case scenario, EPRI estimates the cumulative mitigation required if complementary policies do not deliver any mitigation benefits. In this case, the price of carbon under the cap-and-trade market is likely to be high, and the APCR is likely to be used. With full use of the APCR and zero mitigation from complementary policies, cumulative mitigation is projected to be 273.2 mmtCO2e. As a result, the maxi- mum potential for leakage we estimate here is 68% of the cumulative mitigation expected under this scenario.

Finally, if complementary policies fail, but AB 32 market prices stay below the APCR threshold, cumulative mitigation through 2020 would need to reach 395.0 mmtCO2e. As a result, the maximum potential for leakage we estimate here is 47% of the cumulative mitigation expected under this scenario.

As this discussion illustrates, estimating the cumulative mitigation required under AB 32 requires analytical assumptions about the impact of complementary policies and use of

[147] See Figures 6-1 through 6-3 in EPRI, supra note 44. EPRI assumes that the maximum number of allowances that can be used for compliance under AB 32 are available. In other words, the cumulative mitigation projections are what is needed after covered entities fully exploit the potential for carbon offsets.

allowances in the APCR. For additional context, Table 3 presents a full comparison of all leakage risk scenarios evaluated in this report against the cumulative mitigation scenarios analyzed by EPRI.

Table 3: Maximum Leakage Risk As a Percentage of Cumulative Mitigation Expected Under AB 32 Through 2020 (mmtCO2e).

Resource Shuffling Leakage Risk Scenario		**Cumulative Mitigation Scenario**[148]			
	Complementary Policies' Effects:	None	None	Full	Full
	APCR Use:	None	Full	None	Full
Maximum Coal	Zero-carbon replacement	47%	68%	85%	193%
	Natural gas replacement	27%	39%	49%	111%
Planned Divestment	Zero-carbon replacement	32%	47%	58%	132%
	Natural gas replacement	19%	27%	34%	76%

Although a comprehensive comparison of leakage risks from resource shuffling against cumulative mitigation under AB 32 requires a comparison across multiple variables, one clear pattern emerges: the more successful California's comprehensive climate policy becomes, the more a lax regulation on resource shuffling will undermine the cap- and-trade market. (CULLENWARD 1)

> **Response:** This comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Regulation.

E-3.51. Comment: Appendix III: Leakage Risk Methodology. Note: This appendix provides supporting information for the conclusions presented in Section 4. *[Note: Tables from Appendix III of the commenter's letter are not copied here.]*

We drew upon analysis performed by the California Energy Commission of utility energy supply plans (forms S-2) and utility supply contracts (forms S-5) filed in 2011[149].

[148] For a more complete explanation of the cumulative mitigation requirements under AB 32, see Figures 6-1 through 6-3 in EPRI, supra note 44.

[149] Forms S-2 and S-5 are available at http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2011/ and http://energyalmanac.ca.gov/electricity/s-5_supply_forms_2011/, respectively. At the time of this paper's publication utilities have begun submitting updates forms S-2 and S-5 for 2013, which forms are expected to be compiled and available for further

These forms were submitted by publicly owned utilities and, on a voluntary basis subject to partial confidentiality, the investor owned utilities Southern California Edison and San Diego Gas and Electric. The forms report delivered energy for the years 2009 and 2010, and projected and contracted amounts for years 2011 through 2020. This methodology is essentially equivalent to the approach taken by the draft March 2013 market report from the Emissions Market Assessment Committee members[150].

We identified contracts and resource plans for energy delivery from seven coal-fired sources[151].

Contracted power amounts range from 19 MW (Banning's contract with San Juan Unit 3) to 1,045 MW (Los Angeles Department of Water and Power's partial ownership of the Intermountain Generating Station). Where available, we calculated the emissions associated with each contract for a given year based on the utility's reported planned energy delivery from that source for that year. In years for which a contract remained valid, but the California utility did not report a planned delivered energy amount, we estimated delivered energy and associated emissions based on the simple average of the utility's reported delivered or planned energy from the source between 2009 and 2012.

Our analysis considers two baseline scenarios. In the "Scheduled Divestment" scenario, we calculate baseline emissions based on the length of the California utility contract and on the expected continued operation of the source, as of the time of publication. In other words, we assume that when there are no specific plans in place to retire a power plant, the source will remain in use throughout the lifetime of the contract. While some of the plants that sell power to California utilities may shut down or refuel prior to contract expiration[152] these plants are presumed to continue operations under present circumstances.

In this scenario, where plants are scheduled to close or re-power,[153] we presume that the utility will not enter a subsequent contract for more coal-based power. Because SB 1368 prohibits new long-term contracts for power with coal-level emissions, but does not expressly forbid multiple short-term extensions of existing

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analysis no later than early 2014. Note that this basic methodology is equivalent to the approach taken by Bailey et al., supra note 39. We gratefully acknowledge assistance from the California Energy Commission's Jim Woodward, who helped us identify and better understand the data sources used here. Of course, the opinions expressed in this paper are solely the authors' responsibility

150 Bailey, E.M., S. Borenstein, J. Bushnell, F.A. Wolak, and M. Zaragoza-Watkins, Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market (March 12, 2013), § 5, draft white paper available at http://www.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/BBBWZ_POWER__final(1).pdf . Note that although the authors are affiliated with the EMAC, the draft report does not represent ARB's official position on any issues.

151 Boardman Power Plant, Unit 1; Four Corners Power Plant Units 4 & 5 (treated as one source), Intermountain Generating Station Units 1 & 2 (treated as one source); Navajo Generating Station Units 1, 2, & 3 (treated as one source), Reid Garner Power Plant Unit 4; San Juan Power Plant Unit 3; and San Juan Power Plant Unit 4.

152 Navajo and Four Corners Units 4 & 5, for example, are currently involved in Clean Air Act regulatory processes that may result in decisions to shut down or refuel rather than retrofit to meet new air pollution reduction requirements. See http://www.epa.gov/region9/air/navajo.

153 San Juan Unit 3 is slated to shut down by the end of 2017, despite contracts with California utilities that extend until 2030. See http://www.pnm.com/news/2013/0215-san-juan.htm?source=systems-sj-h. Boardman is scheduled for closure by the end of 2020, but this closure would not have any effects within our study period. See http://www.deq.state.or.us/aq/pge.htm. Reid-Gardner has recently been proposed for early closure in 2017, but this closure is not yet scheduled, and is therefore excluded from our analysis.

contracts,[154] we have also modeled potential leakage based on a “Maximum Coal” baseline scenario.

In the “Maximum Coal” scenario, we assume all existing contracts are extended until scheduled plant closure. Because plant closures do not result in the continued operation of the coal based emission source outside of the California cap, we do not treat this reduction as leakage in either scenario. If a plant were to re-power simultaneously with divestment, leakage proportional to the difference in emissions between the current level and the re-powered level could occur, but the prospects of this situation occurring for any of the plants under consideration here remain purely speculative.[155]
We calculate the emissions associated with each contract on the basis of (1) planned power delivery per year, multiplied by (2) an emission factor based on fuel type, and (3) the plant heat rates. The California Energy Commission provided data on plant-level heat rates, based on the Velocity Suite database[156] and we rely on fuel CO2e emission coefficients published by the Energy Information Administration.[157] Where multiple units are treated as a single source, the simple average of the units’ heat rates is used. Plant data are summarized in Table 4.

In order to calculate leakage potential, for each scenario we modeled two variations: replacement power supplied by zero-emission renewables and replacement power supplied by combined-cycle natural gas. In the case of renewable replacement power, leaked emissions equal 100% of coal-based emissions for which a utility would avoid responsibility through early divestment. Leakage potential for natural gas replacement of energy displaced by early divestment is calculated assuming an Emission Factor of 0.429 mtCO2e/MWh, equivalent to the California Air Resources Board’s designated emission factor for unspecified power.[158] Leakage is determined by calculating the difference between coal-based emissions and emissions from an equivalent supply of natural gas-based energy: leaked emissions are the emissions for which the utility would avoid responsibility through early divestment in coal power and substitution of natural gas power.

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154 See Cal. Pub. Utilities Code § 8341(a) (prohibiting utilities from entering any long-term financial commitment for baseload power unless the generation supplied under the commitment meets state GHG standards); see also § 8340(f) (defining a long-term financial commitment as “either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation”).]

155 Navajo and Four Corners Units 4 and 5 are subject to ongoing rulemaking processes that may eventually result in decisions to re-power, shut down, or partially shut down, but at present there are no firm plans for any particular change in operations. See http://www.epa.gov/region9/air/navajo. Reid Gardner Unit 4 is currently scheduled for retirement in 2023, but the plant’s owner, NV Energy, has recently proposed retiring the unit in 2017. See http://mvprogress.com/2013/04/10/nv-energy- proposes-early-retirement-for-reid-gardner/.]

156 For more information on this privately-owned data aggregation service, see http://www.ventyx.com/en/enterprise/business-operations/business-products/velocity-suite.

157 Voluntary Reporting of Greenhouse Gases Program Fuel Emission Coefficients. http://www.eia.doe.gov/oiaf/1605/coefficients.html.

158 Cal. Code Regs, tit. 17, § 95111(b), available at http://www.arb.ca.gov/cc/reporting/ghg- rep/regulation/mrr-2012-clean.pdf. If, rather than using the Air Resources Board’s value, we had calculated the leakage on the basis of an assumed F-type gas turbine with a heat rate of 6,719 Btu/kWh, burning pipeline-quality natural gas with a carbon content of 53.06 kg CO2/mmBtu (HHV), the emissions factor would have been .357 mtCO2/MWh. Our leakage calculations for this scenario are therefore somewhat more conservative than they may have been under this plausible alternative assumption. See Energy Information Admini- stration, Carbon Dioxide Emissions Factors for Stationary Combustion, available at http://www.eia.gov/oiaf/1605/coefficients.html; see also U.S. Department of Energy, National Energy Technologies Laboratory, Natural Gas Combined Cycle Plant (F-Class) Fact Sheet, http://www.netl.doe.gov/KMD/cds/disk50/NGCC%20Plant%20Case_FClass_051607.pdf.

Table 4: Power Plant Data.

Plant	Utility	Averaged Heat Rate (Btu/kWh)	EIA Emissions Factor (lbs CO2e/MMBtu)	Emissions Factor (mtCO2e/MWh)
Four Corners Units 4 & 5	SCE	10023.5	212.7	0.967
Boardman (owned by Portland General Electric)	SDG&E	11097.0	212.7	1.07
Intermountain Generating Station	LADWP	10823.0	205.3	1.01
Navajo Units 1, 2 & 3	LADWP	10923.3	205.3	1.02
Reid Gardner Unit 4	CDWR	11611.0	205.3	1.08
San Juan Unit 3	Imperial ID	10578.0	212.7	1.02
MSR San Juan Unit 4	Silicon Valley Power	10662.0	212.7	1.03
MSR San Juan Unit 4	Modesto ID	10662.0	212.7	1.03
Intermountain Power Plant Unit 1	Anaheim	10762.0	205.3	1.00
Intermountain Power Plant Unit 2	Anaheim	10884.0	205.3	1.01
San Juan Unit 4	Anaheim	10662.0	212.7	1.03
Intermountain Power Plant	Riverside	10823.0	205.3	1.01
Intermountain Generating Station	Glendale	10823.0	205.3	1.01
San Juan Unit 3	Glendale	10578.0	212.7	1.02
Intermountain Generating Station	Pasadena	10823.0	205.3	1.01
Intermountain Generating Station	Burbank	10823.0	205.3	1.01
MSR San Juan Unit 4	Redding	10662.0	212.7	1.03
San Juan Unit 3	Colton	10578.0	212.7	1.02
San Juan Unit 3 (delivered via exchange)	Azusa	10578.0	212.7	1.02
San Juan Unit 3	Banning	10578.0	212.7	1.02

By a substantial margin, Los Angeles Department of Water and Power (LADWP) is in a position to potentially cause the most leakage by early divestiture. More than 40% of total currently scheduled[159] coal-based utility emissions for the study period are attributable to this contract. If LADWP were to exchange its ownership interest in the Intermountain Generating Station with an out-of-state entity and replace its energy deliveries with renewable sources for which it could report zero emissions, up to 7.7 mmtCO2 per year of leakage would result. If such a divestiture were to occur in 2013, 51.8 mmtCO2 could leak through a single transaction. If all California utilities with an interest in or contract with the Intermountain plant were to divest in 2013 without accompanying plant closure or offsetting external emissions, over 87 mmtCO2 would leak. Although the utility currently has no plans for divestment during the study period, it does intend to transition fully out of its relationship with Intermountain between 2020 and 2025.

Our calculations pertaining to the California Department of Water Resources's (CDWR) energy deliveries from Reid Gardner Unit 4 reflect CDWR's scheduled phase out of that contract, which expires in 2013. For years 2009 through 2012, CDWR received or planned an average of 924 GWh from Reid Gardner. Based on 2011 submissions to the California Energy Commission, CDWR planned to transition to deliveries from the

[159] This contract is therefore associated with 40% of all renewable-replacement leakage potential against the "Planned Divestment" baseline and 27.7% of all renewable-replacement leakage potential against the "Maximum Coal" baseline.]

recently completed Lodi natural gas-fired power plant in California beginning in 2013.[160] During the 2013 transition year, CDWR planned to receive 493 GWh from Reid Gardner, which would be supplemented with energy from the Lodi plant. If our analysis projected backwards to 2009, this transition would represent leakage to be calculated on a natural-gas replacement basis against the Maximum Coal baseline, but it would not represent leakage against the Scheduled Divestment baseline. Against this 2009 baseline, annual potential leakage estimates against the Maximum Coal baseline for this contract would approximately double. In order to capture as complete as possible a range of potential leakage on a consistent methodological basis our analysis calculates both natural gas replacement and renewable energy replacement potential leakage values for this contract, despite CDWR's plan to employ natural gas replacement. Because this is one of the relatively smaller contracts, the difference in potential cumulative leakage between the natural gas and renewable replacement scenarios is 1.8 mmtCO2e against the Maximum Coal Baseline, and 0.20 mmtCO2e against the Scheduled Divestment baseline.

Full results are provided in Table 5 and Table 6, below.

[160] CDWR Public S-2 Supply Form 4-10-11, available at http://energyalmanac.ca.gov/electricity/s-2supply_forms_2011/CDWR%20PUBLIC%20S-2%20Supply%20Form%204-20-11.xlsx

Table 5: Cumulative Leakage Potential, Maximum Coal Baseline Scenario (mmtCO_2e).

Contract Expiration	Plant	Utility	Million Metric Tonnes CO2e By Year 2013	2014	2015	2016	2017	2018	2019	2020	CUMULATIVE LEAKAGE POTENTIAL RENEWABLE REPLACEMENT	NATURAL GAS REPLACEMENT
2016	Four Corners Units 4 & 5	(GWh) SCE	[illegible] 4.96	5,129 4.96	5,129 4.96	5,129 4.96	5,129 4.96	5,129 4.96	5,129 4.96	5,129 4.96	39.68	22.1
2018	Boardman (owned by Portland General Electric)	(GWh) SDG&E	[illegible] 0.58	[illegible] 0.58	[illegible] 0.58	[illegible] 0.58	[illegible] 0.58	[illegible] 0.58	545 0.58	545 0.58	4.67	2.8
2027	Intermountain Generating Station	(GWh) LADWP	7,147 7.20	7,639 7.70	7,398 7.46	6,888 6.94	6,314 6.36	5,794 5.84	5,301 5.34	4,933 4.97	51.82	29.8
2030	Navajo Units 1, 2 & 3	(GWh) LADWP	3,887 3.95	3,887 3.95	3,887 3.95	3,887 3.95	3,887 3.95	3,887 3.95	3,887 3.95	3,887 3.95	31.63	18.3
2013	Reid Gardner Unit 4	(GWh) CDWR	493 0.53	493 0.53	493 0.53	493 0.53	493 0.53	493 0.53	493 0.53	493 0.53	4.24	2.6
2030	San Juan Unit 3	(GWh) Imperial ID	754 0.77	723 0.74	755 0.77	756 0.77	755 0.77	0 0.00	0 0.00	0 0.00	3.82	2.2
2030	MSR San Juan Unit 4	(GWh) Silicon Valley Power	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	3.50	2.0
2030	MSR San Juan Unit 4	(GWh) Modesto ID	424.80 0.59	424.80 0.62	424.80 0.61	424.80 0.62	424.80 0.62	424.80 0.62	424.80 0.62	424.80 0.62	4.90	3.4
2027	Intermountain Power Plant Unit 1	(GWh) Anaheim	902 0.90	958 0.96	902 0.90	961 0.96	902 0.90	958 0.96	902 0.90	961 0.96	7.46	4.3
2027	Intermountain Power Plant Unit 2	(GWh) Anaheim	958 0.97	902 0.91	958 0.97	904 0.92	958 0.97	902 0.91	958 0.97	904 0.92	7.54	4.4
2030	San Juan Unit 4	(GWh) Anaheim	360 0.37	401 0.41	378 0.39	408 0.42	381 0.39	412 0.42	386 0.40	413 0.42	3.23	1.9
2027	Intermountain Power Plant	(GWh) Riverside	1031 1.04	1038 1.05	1020 1.03	1041 1.05	998 1.01	1012 1.02	1028 1.04	956 0.96	8.19	4.7
2027	Intermountain Generating Station	(GWh) Glendale	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	1.98	1.1
2030	San Juan Unit 3	(GWh) Glendale	110 0.11	110 0.11	110 0.11	110 0.11	110 0.11	0 0.00	0 0.00	0 0.00	0.56	0.3
2027	Intermountain Generating Station	(GWh) Pasadena	725 0.73	725 0.73	725 0.73	727 0.73	725 0.73	725 0.73	725 0.73	727 0.73	5.85	3.4
2027	Intermountain Generating Station	(GWh) Burbank	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	4.34	2.5
2030	MSR San Juan Unit 4	(GWh) Redding	60 0.06	60 0.06	60 0.06	180 0.19	180 0.19	180 0.19	180 0.19	180 0.19	1.11	0.6
2030	San Juan Unit 3	(GWh) Colton	[illegible] 0.15	[illegible] 0.15	[illegible] 0.15	[illegible] 0.15	[illegible] 0.15	0 0.00	0 0.00	0 0.00	0.74	0.4
2030	San Juan Unit 3 (delivered via exchange)	(GWh) Azusa	[illegible] 0.20	[illegible] 0.20	[illegible] 0.20	[illegible] 0.20	[illegible] 0.20	0 0.00	0 0.00	0 0.00	1.02	0.6
2030	San Juan Unit 3	(GWh) Banning	[illegible] 0.14	[illegible] 0.14	[illegible] 0.14	[illegible] 0.14	[illegible] 0.14	0 0.00	0 0.00	0 0.00	0.68	0.4
LEAKAGE POTENTIAL	RENEWABLE REPLACEMENT		24.5	25.0	24.8	24.4	23.8	21.9	21.4	21.0	186.9	
	NATURAL GAS REPLACEMENT		14.1	14.4	14.3	14.1	13.7	12.6	12.4	12.1		107.7

Estimated Figure
Plant Closure
Contract Expiration
Scheduled Divestment

Table 6: Cumulative Leakage Potential, Scheduled Divestment Baseline Scenario ($mmtCO_2e$).

Contract Expiration	Plant	Utility	Million Metric Tonnes CO2e By Year 2013	2014	2015	2016	2017	2018	2019	2020	CUMULATIVE LEAKAGE POTENTIAL RENEWABLE REPLACEMENT	NATURAL GAS REPLACEMENT
2016	Four Corners Units 4 & 5	(GWh) SCE	4.96	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	4.96	2.76
2018	Boardman (owned by Portland General Electric)	(GWh) SDG&E	0.58	0.58	0.58	0.58	0.58	0.58	0 0.00	0 0.00	3.50	2.10
2027	Intermountain Generating Station	(GWh) LADWP	7,147 7.20	7,639 7.70	7,398 7.46	6,888 6.94	6,314 6.36	5,794 5.84	5,301 5.34	4,933 4.97	51.82	29.76
Planned Divestment by end of 2015	Navajo Units 1, 2 & 3	(GWh) LADWP	3,887 3.95	3,887 3.95	3,887 3.95	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	11.86	6.86
2013	Reid Gardner Unit 4	(GWh) CDWR	493 0.53	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	0 0.00	0.53	0.32
2030	San Juan Unit 3	(GWh) Imperial ID	754 0.77	723 0.74	755 0.77	756 0.77	755 0.77	0 0.00	0 0.00	0 0.00	3.82	2.21
2030	MSR San Juan Unit 4	(GWh) Silicon Valley Power	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	425 0.44	3.50	2.04
2030	MSR San Juan Unit 4	(GWh) Modesto ID	424.80 0.59	424.80 0.62	424.80 0.61	424.80 0.62	424.80 0.62	424.80 0.62	424.80 0.62	424.80 0.62	4.90	3.44
2027	Intermountain Power Plant Unit 1	(GWh) Anaheim	902 0.90	958 0.96	902 0.90	961 0.96	902 0.90	958 0.96	902 0.90	961 0.96	7.46	4.27
2027	Intermountain Power Plant Unit 2	(GWh) Anaheim	958 0.97	902 0.91	958 0.97	904 0.92	958 0.97	902 0.91	958 0.97	904 0.92	7.54	4.35
2030	San Juan Unit 4	(GWh) Anaheim	360 0.37	401 0.41	378 0.39	408 0.42	381 0.39	412 0.42	386 0.40	413 0.42	3.23	1.88
2027	Intermountain Power Plant	(GWh) Riverside	1031 1.04	1038 1.05	1020 1.03	1041 1.05	998 1.01	1012 1.02	1028 1.04	956 0.96	8.19	4.70
2027	Intermountain Generating Station	(GWh) Glendale	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	245 0.25	1.98	1.13
2030	San Juan Unit 3	(GWh) Glendale	110 0.11	110 0.11	110 0.11	110 0.11	110 0.11	0 0.00	0 0.00	0 0.00	0.56	0.33
2027	Intermountain Generating Station	(GWh) Pasadena	725 0.73	725 0.73	725 0.73	727 0.73	725 0.73	725 0.73	725 0.73	727 0.73	5.85	3.36
2027	Intermountain Generating Station	(GWh) Burbank	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	538 0.54	4.34	2.49
2030	MSR San Juan Unit 4	(GWh) Redding	60 0.06	60 0.06	60 0.06	180 0.19	180 0.19	180 0.19	180 0.19	180 0.19	1.11	0.65
2030	San Juan Unit 3	(GWh) Colton	0.15	0.15	0.15	0.15	0.15	0 0.00	0 0.00	0 0.00	0.74	0.43
2030	San Juan Unit 3 (delivered via exchange)	(GWh) Azusa	0.20	0.20	0.20	0.20	0.20	0 0.00	0 0.00	0 0.00	1.02	0.59
2030	San Juan Unit 3	(GWh) Banning	0.14	0.14	0.14	0.14	0.14	0 0.00	0 0.00	0 0.00	0.68	0.40
LEAKAGE POTENTIAL	RENEWABLE REPLACEMENT		24.50	19.54	19.29	15.00	14.35	12.50	11.41	11.00	127.6	
	NATURAL GAS REPLACEMENT		14.1	11.3	11.2	8.7	8.4	7.3	6.6	6.4		74.1

Estimated Figure
Plant Closure
Contract Expiration
Scheduled Divestment

(CULLENWARD 1)

Response: This comment is outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Regulation; however, ARB staff does provide the following response to the commenter's analysis. The commenter refers to economic analysis that neglects many factors that will limit leakage. The analysis does not reflect the interaction of California's Cap-and-Trade Regulation with the EPS and with Federal regulations such as those designed to reduce regional haze. The combined effect of Federal, California, and other states' policies have worked together to bring about the retirement of many coal resources in the western states.

Legal References and Clean Air Act 111(D)

E-3.52. Comment: My name is Danny Cullenward. I'm here today in my personal capacity. By way of background, I have a law degree and a Ph.D. from Stanford where I worked on the policy for about ten years. I'm now a research fellow at the Berkeley Energy and Climate Institute. One more thing about my background. I've not spoken before this body before, but I was very pleased to be involved in the litigation of a Rocky Mountain farmers union where I represented a group of scientists and very glad to see that the Ninth Circuit has upheld the California's use of the best available environmental science in their climate policy. With that as background, I'm here to talk about a very serious concern about I have about the resource shuffling provisions in the staff proposal today. I'd like to point out that those are almost word for word identical to what the Board had issued as a directive to staff.

Furthermore, the legal case for establishing a stronger rule has improved significantly since the proposed amendments were drafted. The extensive discussion of out-of-state emissions impacts in the context of the dormant commerce clause and extraterritoriality doctrines in Rocky Mountain Farmers Union v. Corey provides strong support for including out-of-state emissions impacts in state-level carbon market regulations.[161] My concern is that these provisions are so broad and vague, they essentially swallow the prohibition on resource shuffling and very easy to put basically any transaction into the safe harbors. The problem with this outcome is almost all economists who have looked at this area agree if there is no effective rule on resource shuffling, the amount of leakage that could come from that is comparable to the scale of the mitigation expected under the can and trade market through 2020.

Let me say a few more words on this problem. I don't think anybody has really thought about what this kind of leakage would mean when the system links with Quebec. I don't think that waiting on EPA regulations for existing sources is a wise policy going forward. The existing source rule under 111(d) of the Clean Air Act at this point is speculation. Finally, some have argued that federal rules addressing greenhouse gas emissions from existing sources under the Clean Air Act will take care of the problem of resource shuffling. These rules have not yet been drafted, however, and should not be taken for granted. While future federal regulations could reduce leakage risks, it would be a mistake to avoid the resource shuffling problem on promise of future EPA action.

[161] Opinion available at http://cdn.ca9.uscourts.gov/datastore/opinions/2013/09/18/12-15131.pdf.

The Obama Administration has promised it by next year. If you look at the litigation possibilities there as well as the delays in the SIP calls, I think it's extremely unlikely we would see effective action from the EPA on existing sources before 2020 when you look again at how the SIP process works out and how long it takes to get attainment and compliance through the SIP process. So I think it would be a huge mistake to permit significant amounts of resource shuffling with the staff proposal that's been submitted before you. I strongly urge you to reach out to people to look for alternative ways of structuring this process.

There are many solutions out there. I've written one. There are many other economists that have other ideas. I strongly encourage you to focus on the market integrity. (CULLENWARD 2)

> **Response:** While ARB staff is aware of federal activity to regulate power plant GHG emissions under section 111(d) of the Clean Air Act, staff does not base its expectations of the future emissions of coal plants in the western United States, and particularly those with which California utilities have contracts, on assumptions about the outcome of the 111(d) process. Instead our analysis is based on continuing observation of coal plant activity in the present and over the last several years. Many different factors, including California's Cap-and-Trade Regulation and EPS regulation, the federal rules to reduce NOx emissions and haze, the low price of natural gas, and actions by other states to reduce GHG emissions, all work together to cause the retirement of high emission coal resources. ARB staff believes that the commenter's expectations about potential leakage are unrealistically high given expected behavior under the current regulatory frameworks. ARB staff believes the resource shuffling provisions as proposed will reduce emissions to the extent feasible as required under AB 32 and create a powerful disincentive for activities in the imported electricity sector that would cause leakage. Should resource shuffling occur, ARB staff will enforce the regulation's resource shuffling provisions.

Definition of Resource Shuffling

E-3.53. Multiple Comments: The definition of resource shuffling should acknowledge that not all substitutions of electricity constitute resource shuffling . To ensure that legitimate transactions that are not currently defined in the "safe harbors" are not later deemed to be resource shuffling, and acknowledging staff's own recognition that there are "several situations in which substitutions of low emission electricity for higher emission electricity may occur that are not undertaken to reduce compliance obligations," the Joint Utilities recommend that section 95802(a)(252) be amended include the underlined text below:

"Resource Shuffling" means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Not all substitutions of electricity between sources with different emission levels are resource shuffling, and Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A). (JUC)

Comment: Resource Shuffling Definition Should be Revised to Provide Greater Market Certainty. Resource shuffling – any attempt to reduce a covered entity's compliance obligation under the Cap-and-Trade by intentionally reducing instate GHG emissions with a corresponding increase in out-of-state emissions – should be prohibited. It is contrary to the state's goal of reducing GHG emissions, and clearly represents a form of leakage. M-S-R has worked alongside CARB staff and other stakeholders to develop definitions for "safe harbor" transactions that would not be deemed resource shuffling, and M-S-R generally supports the proposed revisions in section 95852(b)(2) that provide examples of "safe harbors" that are clearly not instances of resource shuffling. These kinds of legitimate transactions are properly acknowledged in the Regulation itself in order to give both market participants and the market itself greater certainty.

It is important that covered entities not be penalized for legitimate business transactions that merely result in a reduction in the covered entity's compliance obligation. The prohibition on resource shuffling must be carried out in a manner that does not impede other legitimate transactions not specifically set forth in section 95852(b)(2)(A). To that end, M-S-R is concerned with the description of the proposed changes that is found in the ISOR wherein it is noted that "*Staff has also proposed to clearly define as resource shuffling the substitution of relatively lower emission electricity to replace electricity generated at a high emission power plant procured by a First Deliverer under a long-term contract or ownership arrangement, when the power plant does not meet California's EPS, and the substitution is made to reduce a First Deliverer's compliance obligation.*" This explanation is troubling in that it fails to take into account the fact that there may be transactions not currently contemplated by the safe harbor provisions that would involve some of the factors set forth therein, but which would not be undertaken to reduce the compliance obligation. M-S-R is concerned that after-the-fact judgments as to whether the substitution was "made to reduce the First Deliverer's compliance obligation," could result in adverse consequences and needless market uncertainty. M-S-R, like many California utilities, has taken active and aggressive steps to implement early divestiture from its significant economic interests in non-EPS compliant facilities, such as its ownership interest in the San Juan Generating Station located in New Mexico. However, divestiture of an investment made 30 years ago, and which is backed by municipal bonds, must be done in manner that recognizes M-S-R's fiduciary duty to its member-ratepayers and bond holders. The divestiture cannot be done in a vacuum, as the ownership interest is part of multi-state, multi- contract, and multi-party arrangements. The complexities associated with such a divestiture were recognized by CARB in Appendix A to the Regulatory Guidance Document,5 and M-S-R wants to ensure that all steps taken by entities (such as M-S-R) that hold long-term contracts or ownership shares in facilities that do not meet the EPS and that are attempting to transition out of those contracts are not deemed resource shuffling. This statement is also not entirely consistent with the statement on the previous page of the ISOR wherein staff states that "*based on discussions with stakeholders, staff recognized that there are several situations in which substitutions of low emission electricity for higher emission electricity may occur that are not undertaken to reduce compliance obligations."6 The Proposed Amendments to the Regulation should be revised to reconcile these two statements. Accordingly, M-S-R recommends that section 95802(a)(252) be amended include the following phrase (as proposed in JUG comment):*

<u>Not all substitutions of electricity between sources with different emission levels are resource shuffling, and…</u>

There are myriad legitimate business transactions that may result in a California entity not importing all of the electricity it contracts for out-of-state, or result in the covered entity substituting electricity from one source with electricity from another source before it reaches California's borders. These transactions may be necessitated by timing, contractual obligations, transmission availability, preexisting exchange agreements, and related electricity deliverability issues. They may also be part of larger procurement and compliance designs that implicate – but are not driven by – the covered entity's compliance obligation under the Regulation. While the safe harbor provisions of section 95852(b)(2)(A) capture known transactions that would reflect many kinds of legitimate situations, the list is not exhaustive, nor does it take into account new or emerging business transactions. It is imperative that the Regulation recognize as yet undefined transactions that do not fall within any of the existing safe harbors, but which should not be deemed resource shuffling, and ensure that the definition of resource shuffling found in the Regulation reflects this. M-S-R also supports formally removing the attestation requirement as proposed in section 95852(b) of the Proposed Amendments. (MSR 1)

Comment: LADWP appreciates ARB's efforts in working with electric utility entities to develop ARB's Resource Shuffling guidelines. LADWP further supports the inclusion of the guidelines into the rule which provides more certainty with respect to compliance with the regulation with a couple of minor changes.

There are situations resulting in GHG emissions reductions that have occurred that are not Resource Shuffling and may not fall into a specific Safe Harbor. Thus, LADWP recommends that CARB add the following phrase to the end of the Resource Shuffling proposed definition and appending the last sentence: "Not all substitutions of electricity between sources with different emission levels are resource shuffling, and…[last sentence]" (LADWP 1)

Comment: NCPA appreciates that the Proposed Amendments would include the definition of resource shuffling and proposed "safe harbors" that were previously found in the Regulatory Guidance Document, and strike the attestation requirement. Resource shuffling undertaken to avoid a compliance obligation under the Cap-and-Trade program is properly prohibited in the Regulation, and the proposed revisions go far in explaining how this restriction is intended to work. The Regulation should also be drafted in such a way as not to constrain or impede legitimate electricity transaction merely because the generation resources used in those transactions may not have the same GHG emissions.

Resource shuffling must be a transaction that involves a plan, scheme, or artifice on the part of the compliance entity. As the ISOR recognizes, there are “several situations in which substitutions of low emission electricity for higher emission electricity may occur that are not undertaken to reduce compliance obligations.” The conditions and safe harbors listed in section 95852(b)(2)(A) of the Proposed Amendments include the most common kinds of transactions involving electricity imports with substitutions between sources with different emissions levels. However, the prohibition in section 95852(b)(2)(B)(1) may inadvertently capture legitimate, yet undefined, transactions. The safe harbor list is not exhaustive, and myriad transactions could result in the appearance of resource shuffling, but in fact, involve no plan, scheme, or artifice on the part of the first deliverer to reduce its emissions compliance obligation. Accordingly, section95802(a)(252) of the Regulation should be amended to clearly reflect this, by adding the following text before the last sentence in the definition: “Not all substitutions of electricity between sources with different emission levels are resource shuffling, and [last sentence]” (NCPA 1)

Comment: On the issue of resource shuffling, we fully support including all of the provisions for the safe harbors in the body of the regulation. We just ask for a slight additional modification to address instances where there are transactions that we don't know what the form or shape they're going to take right now, but they're clearly not undertaken for purposes of avoiding a compliance obligation. And we want to ensure that down the road and after the fact review of these transactions will not cause an entity to be in violation of the resource shuffling provision. (NCPA 2)

Comment: SCPPA appreciates the new section included in the regulation the resource shuffling save harbors that were developed in 2012. However, SCPPA recommends a couple of clarifications, particularly a clarification that there may be other legitimate transactions that aren't captured by the safe harbors. (SCPPA 2)

Comment: Staff proposes to amend the definition of resource shuffling from its longstanding focus on a plan, scheme or artifice “to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid,” and explicitly exempt electricity deliveries that qualify for one of 13 “safe harbors” listed in section 95852(b)(2)(A). *[Note: ARB would like to point out that the commenter quotes a staff draft version of the regulation, not the definition from the proposed amendments which leaves out the words “involving delivery of electricity to the California grid”.]*

“Resource Shuffling means any plan, scheme, or artifice <u>involving the delivery of electricity to the California grid undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries</u>

from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A)." (NRDC 3)

Comment: The definition of "Resource Shuffling" should be revised for clarity. The proposed changes to the definition of "Resource Shuffling" in section 95802(a)(317) define it as:

any plan, scheme or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A).

SCPPA supports this revised definition and the safe harbors listed in section95852(b)(2)(A). However, while the safe harbors will cover most of the legitimate transactions

SCPPA members can envisage, it is important that the prohibition on resource shuffling does not impede other legitimate (but as yet undefined) transactions that are not specifically covered in the safe harbors.

Therefore, as proposed by both the Northern California Power Agency and the M-S-R Public Power Agency in their comments to the ARB dated August 2, 2013, a phrase should be added to the definition of "Resource Shuffling" in section 95802(a)(317) to clarify this point.

In addition, the purpose of the word "resources" in the repeated phrase "electricity deliveries from sources with relatively higher emissions resources" is unclear; this word may need to be removed.

Recommendation: SCPPA's proposed changes to section 95802(a)(317) are set out below:

(317) "Resource Shuffling" means any plan, scheme or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions ~~resources~~ to reduce its emissions compliance obligation. Not all substitutions of electricity between sources with different emission levels constitute resource shuffling, and r~~R~~esource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions ~~resources~~

when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A). (SCPPA 1)

Response: The commenters request that ARB staff include the phrase "not all substitutions of electricity between sources with different emission levels are resource shuffling" in the definition of resource shuffling. ARB staff declines to make this change since only a "plan, scheme, or artifice" is considered resource shuffling and there may be various substitutions that are not covered in a safe harbor but nonetheless are not resource shuffling. Because the electricity markets are constantly evolving, ARB staff cannot possibly delineate in advance all possible transactions as either resource shuffling or not resource shuffling. ARB staff will determine on a case-by-case basis whether activities constitute resource shuffling. Staff believes that the modified definition as proposed provides sufficient clarity as was indicated by many of these stakeholders during the regulatory development process.

Some commenters are concerned that the resource shuffling prohibition could impede legitimate transactions not included as one of the safe harbors of section 95852(b)(2)(A). ARB staff believes that taken as a whole, the proposed definition of resource shuffling and the proposed provisions dealing with resource shuffling will only impede transactions in which a substitution is made to as part of a plan, scheme or artifice to reduce compliance obligation. ARB staff agrees that there may be myriad legitimate transactions that involve substitutions of electricity for a large variability of reasons that are not resource shuffling, including some that may not fit under section 95852(b)(2)(A), but staff does not believe a regulatory change is needed to recognize this fact.

As previously stated in published guidance, ARB staff will work with entities that hold long-term contracts or ownership shares in facilities that do not meet the EPS to address their transition towards divestment in order to ensure that the steps taken do not constitute resource shuffling.

E-3.54. Comment: NRDC asks that ARB not loosen the rules on resource shuffling. On resource shuffling, we ask the Board to tighten the rules. We appreciate and recognize the ultimate and best solution is to get other jurisdictions on board. Certainly thank California and ARB in particular for everything it is doing to help and encourage that along. We also recognize in combination with other AB 32 policies California is having outside impact on emissions well beyond its borders, but well within its legal limits, of course.

In the meantime, as we heard from Mr. Cullenward who has studied this issue, resource shuffling is a trap door that can severely undermine the effectiveness of the program. At a minimum, we ask the Board to direct staff to ensure it retains its authority to prohibit transactions it has long considered resource shuffling, such as laundering and contract swapping, despite the presence of the safe harbor. I have comments I will submit to that effect today. (NRDC 4)

Response: The proposed provisions of section 95852(b)(2)(B) directly address laundering and contract swapping that involves coal power under contract to California EDUs. ARB staff added these provisions to recognize that, absent the prohibition on laundering and contract swapping, there would be a very significant potential for leakage involving EPS-non-compliant power plants. ARB staff will closely monitor electricity importing activities and the disposition of power from the EPS-non-compliant power plants. ARB staff will also monitor disposition of hydropower and other low emission power to monitor potential leakage or resource shuffling. Based on the monitoring activities, ARB staff will enforce the prohibition on resource shuffling.

E-3.55. Comment: The proposed amendments contain both affirmative examples of electricity deliveries that would constitute resource shuffling (in Section 95852(b)(2)(B)) and a series of exemptions or "safe harbors" for transactions ARB would not consider resource shuffling (in Section 95852(b)(2)(A)). The rule is silent, however, on where the burden lies to qualify for a safe harbor, and fails to address the possible conflict between the presence of a safe harbor and one of the prohibited forms of resource shuffling specified in the rule.

Recommendation: Accordingly, we recommend ARB:
1. Clarify the hierarchy of authority between the safe harbors and prohibited forms of resource shuffling. In the event a first deliverer exploits a safe harbor to undertake a plan, scheme, or artifice to reduce its emissions compliance obligation in a manner that would otherwise constitute a prohibited form of resource shuffling, ARB should clarify the transaction constitutes a violation of the article and is subject to an enforcement action.

2. Put the burden of proof on first deliverers of electricity to satisfy the conditions necessary to claim exemption under one of the safe harbors.

We propose modifications to the definition of resource shuffling to address these two concerns. We also ask the Board to direct staff to further examine the scope and definitions of the safe harbors with the aid of the Emissions Market Assessment Committee (EMAC) over the next year.

The scope of the proposed exemptions is exacerbated as the rule is silent on where the burden lies to qualify for a safe harbor, or how the safe harbors relate to the affirmative examples of resource shuffling identified in Section 95852(B). It is entirely conceivable that electricity deliverers will attempt to structure a transaction that constitutes a plan, scheme, or artifice to resource shuffle within one of qualifying safe harbors. For example, safe harbor two explicitly permits both "cherry picking" and "facility swapping," two examples of resource shuffling ARB has long identified as prohibited[162] as long as the delivery was intended to

[162] Throughout the rulemaking process, ARB identified three practices it considers resource shuffling: 'facility swapping' (replacing power that has a high emissions factor with power that has a lower emissions factor), 'cherry picking' (replacing power that has

comply with state or federal law. A first deliver could also claim exemption for facility or contract swapping by simply claiming the transaction was "necessitated" by the termination of the contract under safe harbor 2 [sic].

Recommendation: As proposed below, we therefore urge ARB at a minimum to clarify (1) that the presence of a safe harbor is not an absolute shield from liability if ARB determines the transaction constitutes a prohibited form of resource shuffling specified in the rule; and (2) that the burden is on first deliverers to establish they satisfy conditions to qualify for a safe harbor.

NRDC proposes the adding the underlined text to the definition of resource shuffling in Section 95802(a)(317):

Resource Shuffling means any plan, scheme, or artifice involving the delivery of electricity to the California grid undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A), <u>unless ARB determines the substitution is prohibited pursuant to the conditions listed in section 95852(b)(2)(B). A First Deliverer of Electricity bears the burden of establishing that an electricity delivery satisfies the conditions listed in section 95852(b)(2)(A).</u>

We appreciate the Board's attention to this issue and look forward to working closely with ARB staff and other stakeholders. (NRDC 3)

Response: There are many economic and regulatory drivers for First Deliverers that participate in western electricity markets to engage in various activities that may or may not be tied to the existence of a Cap-and-Trade Program. ARB defines resource shuffling as a “plan, scheme, or artifice.” ARB staff devised a regulatory approach after much stakeholder input that would minimize leakage, work in concert with other state and federal laws and regulations, recognize the limits of California’s jurisdiction, and provide reasonable assurance to First Deliverers that longstanding practices to minimize cost and maintain reliable power would not be considered as resource shuffling. We believe that the proposed amendments strike a delicate balance that will accomplish these needs.

The commenter does not provide data or evidence to support its claim that the proposed resource shuffling provisions would lead to significant leakage. The commenter also notes that practices such as cherry picking and resource

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an unspecified emissions factor with power that has a specified, lower emissions factor). and 'laundering' (replacing power that has a high emissions factor with power that has an unspecified emissions factor).

swapping, terms used to characterize types of resource shuffling, during early development of ARB staff's approach, may occur with safe harbors. However, within ARB staff's balanced approach, other exigencies mean that some actions that look similar to cherry picking or resource swapping do not meet the definition of resource shuffling, including some actions that may result in leakage that cannot be prevented.

Specifically, the commenter recommends adding language to the definition of resource shuffling that would subordinate all "safe harbor" provisions of section 95852(b)(2)(A) to the prohibited activities listed in section 95852(b)(2)(B). ARB staff believes that this addition would upset the balance sought by ARB staff. Furthermore, staff recognized that short term transactions (subject to safe harbors nine and ten) did in fact need to be subordinated to the prohibitions of section 95852(b)(2)(B).

The commenter requests that ARB staff add the following to the resource shuffling definition: "A First Deliverer of Electricity bears the burden of establishing that an electricity delivery satisfies the conditions listed in section 95852(b)(2)(A)." ARB staff will enforce the resource shuffling provisions. Each enforcement case under the resource shuffling provisions will be evaluated based on the specific facts presented.

E-3.56. Comment: A. Proposed Changes to the Resource Shuffling Definition – Offsetting Increase Requirement. AEPCO's first comment relates to the proposed change to the resource shuffling definition in Section 95802(a) of the Cap-and-Trade Regulation (Appendix E, Proposed Regulation Order at 47). As proposed, the revised definition would read:

(317) "Resource Shuffling" means any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A).

As ARB's Initial Statement of Reasons (ISOR) explains, resource shuffling is a form of leakage, which is defined in the California Health and Safety Code as "a reduction in emissions of greenhouse gases within the state *that is offset by an increase in emissions of greenhouse gases outside the state*." ISOR at 30 (quoting Cal. Health & Safety Code §38505(j)) (emphasis added). The ISOR also recognizes that "[r]esource shuffling always involves such a substitution *that would result in an apparent emissions reduction in California that is offset by an increase in emission outside of California* where the electricity from the higher emission resource is deemed to be consumed." ISOR at 30 (emphasis added).

However, the proposed revisions to the resource shuffling definition omit the element of an offsetting increase in emissions outside of California. Because of this omission, the amended provision, if read literally, could prohibit activities that are not leakage or resource shuffling. The lack of any requirement that substitutions must be associated with offsetting increases in emissions outside of the state to be considered resource shuffling could prohibit legitimate, beneficial emission-reducing activities.

For example, if a first deliverer were to substitute natural gas for coal at an electric boiler unit that is capable of burning both fuels (*i.e.*, "fuel switch") in order to reduce the GHG emission rate for electricity delivered to California (thereby reducing the first deliverer's compliance obligation), this activity could be considered a "plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation." In other words, this substitution of low-emitting power for high-emitting power could constitute "resource shuffling" under the proposed definition—even though the overall level of GHGs would be reduced, and even though this reduction in emissions would not be "*offset by an increase in emissions of greenhouse gases outside the state*." Similarly, the substitution by a first deliverer of zero-emitting power from a new (greenfield) zero-emission facility for electricity deliveries from a high-emitting fossil-fueled source could be considered a "plan, scheme, or artifice . . . to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation" even if the substitution resulted in an overall *reduction* in overall emissions from the fossil-fueled source.

Neither of the above examples would constitute "leakage" as defined by the A.B. 32 statute, because neither example would lead to "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." Cal. Health & Safety Code § 38505(j). Furthermore, both examples would advance one of the primary goals of AB 32, *i.e.*, "to reduce emissions of greenhouse gases." *See* Cal. Health & Safety Code § 38501(c). Consequently, the proposed definition appears to prohibit activities that 1) are not leakage, and 2) would further the goals of AB 32.

> **Recommendation:** We propose that ARB modify the definition of "resource shuffling" to conform with the Health and Safety Code's definition of leakage and ARB's stated understanding of the concept of "resource shuffling." Specifically, ARB should clarify, consistent with its statement in the ISOR, that substitutions that do not result in an offsetting increase in emissions outside of California are not resource shuffling. This clarification could either be inserted into the amended definition of resource shuffling in section 95802, or as an additional enumerated "safe harbor" in section 95852(b)(2)(A) (Options 1 and 2 below).

Option 1. Append the following language to the definition of resource shuffling: *"or when the substitution does not result in an offsetting increase in emissions outside of California."*

Option 2: Amend Section 95852(b)(2)(A) by adding the following subparagraph as an additional safe harbor that does not constitute resource shuffling: "Substitutions that are not the result of plans or schemes to lower California GHG compliance obligations while causing an offsetting increase in emissions outside of California." (AEPCO)

Response: The commenter would like ARB staff to change the definition to make an unnecessary statement in the regulatory language. The Regulation, together with the ISOR and the history of addressing resource shuffling, is sufficiently clear about this topic, so no change is needed.

Resource Shuffling Not Involving Legacy Coal

E-3.57. Comment: WPTF appreciates CARB's efforts to further clarify the regulatory prohibition against resource shuffling through the codification of the 'safe harbor' exclusions and the elimination of the attestation. While the elimination of the attestation is helpful, if CARB intends to enforce the prohibition, then it is critical to provide further clarity about what does and does not constitute resource shuffling. In particular, we do not believe that the proposed definition of resource shuffling or the proposed provisions in Section 95852(b)(2) provide sufficient clarity regarding imports of low emission power when the import is not a substitute for power previously provided by a high emission resource under long term contract.

We have several reasons for this concern. First, while both the definition of resource shuffling and the provisions of Section 95852(b)(2) suggest that CARB is most concerned about scenarios under which a high emission resource under long term contract to a California utility, or owned by a first deliverer, is inappropriately substituted, use of the word "include" in the main paragraph of 95852(b)(2)(B) and the staff explanation provided during the July 18th workshop indicates that other scenarios could constitute resource-shuffling. Yet the proposed language provides no indication of what these scenarios would be. Based on earlier comments and discussion, we understand that CARB staff remains concerned regarding the possibility of 'facility swapping' and 'cherry picking' by a first deliverer with a portfolio of resources. If this is true, then these scenarios should be explicitly identified and defined in the regulation.

Second, section 95852(b)(2) makes a partial distinction between long-term and short-term contract arrangements. Imports pursuant to short-term contracts or via the CAISO markets are a clear safe-harbor, provided that the import is not associated with the inappropriate diversion of electricity from a high-emission resource under contract to a California utility. Similarly, 95852(b)(2)(B)(1) and (2) refer to high emission resources under long-term contract. However, no guidance is provided on imports from low-emission resources. Safe harbor 10 would appear to apply if electricity from low-emission resources is imported via short term contracts, but the regulation is silent on whether imports from low-emission resources pursuant to new long-term contracts are acceptable.

For these reasons, WPTF considers it imperative that CARB provide more clarity around the resource shuffling provisions. We recommend the [one of the] following two paths:

1. If CARB is <u>solely</u> concerned with inappropriate diversion of high---emission resources that are owned by or under long---term contract by the first deliverer or a California utility, then the definition of resource shuffling should be revised to explicitly state this, similar to the language used in 95852(b)(2)(B). We would suggest something along the lines of the following:

> "Resource Shuffling" means any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute <u>delivery of</u> electricity deliveries <u>from a power plant that does not</u> <u>meet the California EPS and that is owned by or under long---term contract to the First</u> <u>Deliverer or to a California Electrical Distribution Utility with delivery of electricity</u> from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A)."

2. If CARB is <u>not</u> solely concerned with the with inappropriate diversion of high---emission resources that are owned by or under long-term contract by the first deliverer or a California utility, then, A) Expand Section 95852(b)(2)(B) to explicitly define the other scenarios, such as facility-swapping or cherry-picking, that would be considered resource-shuffling; and, B) Provide an additional safe-harbor in section 95852(b)(2)(A) to exempt delivery of electricity under long---term contract provided that the activity is not linked to diversion of a high emission resource:

> "Long-term transactions and contracts for delivery of electricity with terms of greater than 12 months, unless such activity is linked to the selling off of power from, or assigning of a contract for, electricity subject to the EPS rules from a power plant that does not meet the EPS with which a California Electricity Distribution Utility has a contract, or in which a California Electricity Distribution Utility has an ownership share, that is not covered under paragraphs 11, 12 or 13 below." (WPTF 1)

> **Response:** ARB staff cannot foresee all possible transactions structures that may or may not constitute resource shuffling. ARB staff will determine on a case-by-case basis whether activities constitute resource shuffling. While the terms "facility swapping" and "cherry picking" have been useful in developing concepts of resource shuffling throughout the regulatory process, there terms are not clear enough to include in the Regulation. Instead, through a strong

stakeholder process, staff developed the current approach which strikes the right balance of describing important safe harbors and prohibited actions while having the breadth to cover new transactions that may meet the definition of resource shuffling.

The safe harbors, including safe harbor 10, apply to substitutions of all kinds, including for example substituting low emissions power such as hydrdoelectric power for higher emission power such as unspecified or fossil power. While some of the Regulation's safe harbors do distinguish between short term and long term contracts, it does not call out new long-term contracts for low-emission resources. Instead, if electricity purchased under such contracts is imported, ARB staff would rely on the general definition of resource shuffling. The test would be determining if a First Deliverer had engaged in a plan, scheme, or artifice to reduce their compliance obligation through a substitution that occurred pursuant to the new long-term contract.

ARB staff recognizes that resource shuffling may involve low emission resources and that the situation for low-emission (typically hydroelectric) power is very different than that of the non-EPS-compliant plants under contract to California EDUs. ARB staff will evaluate activities across the electricity sector to monitor the potential for leakage.

Resource Shuffling Not Involving Coal

E-3.58. Comment: Another concern of Brookfields is: 2) The proposed safe harbors focus only on conditions under which California utility legacy contracts of high emissions power might be diverted. It is still unclear whether or not market activities outside of this definition are considered resource shuffling.
IV. If CARB is solely concerned about resource shuffling of high emissions resources the regulation should be explicit and/or a specific list of impacted contracts be provided to the market. The current language suggests that CARB is only concerned with resource-shuffling of high emissions resources. The existing safe harbor provisions focus only on conditions under which California utility legacy contracts of high emissions power might be diverted and do not provide any clarity for market transactions outside of this definition.

If CARB is only concerned about resource shuffling of high emissions resources as the regulation seems to indicate, then Brookfield requests the language explicitly state this fact and include a list of impacted fuel types. To go even further, and provide more assurance to the market, CARB could list specifically the contracts and companies that hold those contacts that cannot be changed that fall within the definition that is alluded to in the regulation. The market is aware of most of these contracts so why not explicitly name them and limit the definition of resource shuffling to market transactions around these specific facilities.

If CARB is concerned with other market transaction types additional specific conditions must be included to the safe harbors as well as transactions types not allowed under the resource shuffling definition. Since there will always be market transactions that fall outside of the scenarios that CARB could list in the regulation there must be an avenue for a market participant as we describe above, to get pre-approval for these market transaction. Brookfield realizes that this process could be very onerous but unless the definition of resource shuffling is narrowed significantly there will continue to be a larger burden placed upon the CARB to resolve the market uncertainties. (BEM 1)

> **Response:** The commenter believes the regulation is unclear about whether or not market activities that are not related to diversion of power from California utility legacy contracts with high emissions resources (EPS-non-compliant resources) could be considered resource shuffling. ARB staff recognizes that resource shuffling may involve low emission resources and unspecified power, and that the situation for low-emission (typically hydroelectric) power is very different than that of the non-EPS-compliant plants under contract to California EDUs. ARB staff will evaluate activities across the electricity sector to monitor the potential for leakage. Because shuffling of high emission resources is not ARB staff's sole concern, staff declines to implement the changes proposed.
>
> ARB staff believes the commenter's concerns here are due to a misunderstanding of the staff's overall approach to resource shuffling. ARB staff cannot foresee all possible transactions structures that may or may not constitute resource shuffling. ARB staff will determine on a case-by-case basis whether activities constitute resource shuffling. Section 95852(b)(2)(B) of the Regulation focuses on prohibiting the largest potential source of leakage due to resource shuffling, which is the disposition of power from non-EPS-compliant power plants under long term contract or owned by California utilities. For other transaction types, the definition of resource shuffling will be used to determine whether a transaction is resource shuffling. First Deliverers are encouraged to talk to ARB staff regarding specific transactions they are contemplating before they are finalized.

Responsible Parties

E-3.59. Comment: I. As described in more detail below, however, the regulations still remain silent in several key areas that need be addressed. Additional clarity must be provided by CARB through the Cap-and-Trade Regulation to allow the energy markets to operate efficiently and to avoid negatively impacting liquidity for imported power. One of Brookfield's concerns is:

I. The Cap-and-Trade Regulation remains silent as to what extent the enforcement of resource shuffling activity could apply to historic procurement practices beyond the actions of the First Deliverer.

II. The definition and enforcement of resource shuffling must be limited to the activities of the First Deliverer and not extend to other entities historical procurement patterns. Although the definition of resource shuffling states that “Resource Shuffling” means any plan, scheme, or artifice to receive credit based on emissions reductions that have not occurred, involving the delivery of electricity to the California grid undertaken by a First Deliverer of Electricity…. it is unclear as to whether the CARB limits it definition of resource shuffling to the involvement in a scheme or artifice by the First Deliverer only or if the CARB intends to use historical procurement patterns performed by other entities that occurred prior to the importer procuring the energy as a baseline in determining whether a First Deliverer has engaged in resource shuffling. Brookfield believes that any definition of resource shuffling must be limited to the First Deliverer’s actions. Anything beyond that exposes First Deliverers that are buyers of power to risks that cannot be controlled or mitigated. As the proposed regulations currently stand, First Deliverers are taxed with an unfair burden of due diligence to evaluate whether or not the historical procurement patterns that occurred previously do not fall into the definition of resource shuffling. If CARB takes into consideration the actions of the entity from whom the First Deliverer procures energy from in assessing whether resource shuffling has occurred, it would be necessary and prudent for the First Deliverer to complete a detailed review of the activities and historical patterns of such entity. It would be very difficult for a First Deliverer to determine with any certainty whether such activities have occurred. Due to confidentiality reasons, it is very unlikely that the entity from whom the First Deliverer is procuring energy from would allow the First Deliverer access to the records necessary to complete this review. Indirectly imposing such a burden on the First Deliverer is not only unreasonable and outside of current market practices, but could also have the effect of hindering the import of legitimate clean energy into California and disputing legitimate business activities.

Without further clarity, the regulation as it stands could deem any purchase of power, even short-term purchases, as possible subject to resource shuffling enforcement action. Consequently, a First Deliverer should only be held accountable for its own portfolio and historical procurement patterns and should not be held liable for the historical actions of suppliers further up the transaction chain. We propose the following changes to the definition of resource shuffling to achieve this goal.

> “Resource Shuffling” means any plan, scheme, or artifice directly undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for Electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A).
>
> A determination of whether or not an entity has engaged in resource shuffling, whether for enforcement purposes or otherwise, shall be limited to the market transactions directly initiated by the First Deliverer. For the avoidance of doubt,

any determination of resource shuffling shall not consider any actions or behavior engaged in by parties other than the First Deliverer.

If CARB is unable or unwilling to exclude historic procurement practices of entities other than the First Deliverer from its determination of resource shuffling activity then the regulation must be modified to explain in detail how procurement patterns would be utilized and for what timeframe. Also, more scenarios will need to be added to the list of safe harbors to provide market certainty. To that end, Brookfield recommends a one year time limit be enacted for evaluation of historical procurement patterns and the addition of a new safe harbor that exempts new incremental contracts for energy. Therefore entities that do not have existing contracts or that do not exit existing contracts cannot be deemed to have resource shuffled as they are not changing historical behavior or substituting power.

The task of modifying the regulation to an extent that would allow the market to function properly under these ambiguous conditions will be extremely burdensome for CARB. Consequently, if these requirements are left unaddressed the result will be continued market uncertainty and paralysis. The best solution is for CARB to focus on what it can control through its jurisdiction which is actions performed by the First Deliverer only.
III. Brookfield requests CARB propose specific contract language that if included in a bilateral contract or a pre-certification option that will ensure a buyer will not be held liable for other entities' resource shuffling activities.

As noted above, Brookfield is very concerned that the existing regulations would permit CARB to pursue enforcement action against a First Deliverer for resource shuffling due to the actions of the seller or supplier that may occur further up a chain of market transactions. If CARB intends to expose buyers to scrutiny for actions taken by entities other than the First Deliverer, then guidance must be provided by CARB which will allow First Deliverers to protect itself from consequences as a result of these actions. Brookfield proposes three possible solutions which would address this concern.

1) CARB approved language that bilateral counterparties can include in their contracts that ensures that power sold does not meet the definition of resource shuffling. For example, the seller would certify to the buyer that low emissions power is being sold and that it is not replacing energy from a high emissions facility that previously served California load or that the low emissions power being sold is in excess of the load serving entities' load serving obligations The First Deliverer would request specific representations from its counterparties that would allow the First Deliverer to import purchased power with the comfort that such import would not constitute resource shuffling. If this language is included in a bilateral contract and signed by the parties the First Deliverer would not be held liable by CARB for resource shuffling activities specific to that particular energy transaction. If the First Deliverer were able to rely on these CARB approved representations, then it would be relieved from having to complete an unreasonable level of due diligence.

2) Tri-party agreement signed by CARB, First Deliverer, and supplier that confirms that the market transaction is certified as a resource shuffling safe harbor.

3) Provide suppliers an avenue through CARB to pre-certify their power as resource shuffling free. The seller could then provide this signed certification to the buyer and this certification could continue to stay with the chain of market transactions that might result from the original source.

Under all three options proposed above no further proof would be required for carbon reporting verification.

Brookfield recommends CARB institute a stakeholder process immediately whereby the alternatives we suggest above and others can be further explored and developed. This is critical to provide buyers and sellers an alternative to avoid resource shuffling. Currently, the only way for buyers to avoid the risk of resource shuffling in its entirety is to stay out of the market. (BEM 1)

> **Response:** The regulatory language on past sales and purchases is specific to section 95852(b)(2)(A)(9),for clarity regarding safe harbor nine. Section 95852(b)(2)(A)(9) states that in evaluating short term deliveries linked to the selling off of power from non-EPS compliant power plants and based on economic decisions including congestion costs but excluding implicit and explicit GHG costs, "ARB staff will consider the levels of past sales and purchases from similar resources of electricity, among other factors, to judge whether that activity is resource shuffling." In this context, such consideration of historical sales and purchases is explicit for the linked transactions that are the subject of this safe harbor. This language was included to provide greater clarity for situations in which these linked deliveries may occur when high-emission power is sold off, not to avoid a compliance obligation, but in consideration of other reasons such as transmission constraints or congestion costs. It is not possible to say in advance when historical procurement patterns would or would not be used in any particular potential investigation.
>
> Because resource shuffling is defined as a "plan, scheme, or artifice" it is possible that a First Deliverer could collude with another party to devise linked transactions to reduce its compliance obligation.
>
> ARB staff agrees with the commenter that the definition and enforcement of resource shuffling should be limited to activities of the First Deliverer and not extend to other entities' historical procurement patterns. However the historical procurement patterns of a First Deliverer's counterparty may be relevant in determining that a First Deliverer's collusion with the counterparty could be resource shuffling. First Deliverers are not exposed to risks that cannot be controlled or mitigated; therefore, the Regulation does not require that a First Deliverer know the full history of its counterparties. A First Deliverer can control

risk by refraining from participating in a plan, scheme, or artifice to avoid compliance obligation.

Investigation and Enforcement Process

E-3.60. Comment: 4) The method through which resource shuffling "will be identified and investigated" is not explained in the regulation. VII. A transparent process is needed for the investigation and enforcement of resource shuffling activity.
CARB must include in the regulation what methods will be used to identify resource shuffling activities and what process would be followed to investigate a First Deliverer once the activity is identified. This should include a time limit for notification by CARB once potential resource shuffling activities are identified (i.e. within 30 days of identification) a timeline for responses from the First Deliverer to produce necessary data and documentation, and a timeline for when the total investigation must be completed. Once an investigation is completed next steps should be identified. The regulation is completely silent on this detail which is problematic as it appears there are no bounds around what could happen and in what timeframe.

Recommendation: In summary our recommendations are as follows:

- Clarify that the First Deliverer will not be held liable for resource shuffling performed by a supplier or another power entities historical action that occurred further up a market transaction chain
- Narrow definition of resource shuffling to be specific to the lay-off of high emissions power and include impacted fuel types and possibly companies and contracts
- Provide a channel either through bilateral contracting language or pre-certification to allow buyers and sellers to manage resource shuffling risk
- Address problematic language in the regulation is it pertains to safe harbors for short-term transactions to allow the market to operate efficiently
- Provide a transparent process for how resource shuffling will be identified and investigated

Brookfield appreciates the opportunity to submit comments and recommends that CARB adopt the recommendations outlined herein. (BEM 1)

Response: ARB staff is committed to monitoring transactions that may be potential resource shuffling. All oversight functions are part of implementation and need not be specified in the Regulation. To monitor resource shuffling, ARB staff will review data reported under MRR by electricity importers and other available data on electricity generation and transactions, and intends to enforce the prohibition when evidence of a violation is found.

Asset Controlling Supplier

E-3.61. Comment: 1. Powerex Welcomes ARB's Proposed New Definition of "Resource Shuffling," But it Needs Further Clarification. Powerex welcomes ARB's proposed new definition of “resource shuffling” in section 95802(a)(317), and appreciates the work that ARB has done to address this issue over the course of many months. [Footnote omitted.] The new definition is far more specific than the prior version, and Powerex agrees that the term — and thus also the prohibition set forth in CTR § 95852(b)(2) — must be limited to First Deliverers of Electricity. However, in the context of a First Deliverer that also is an asset controlling supplier (“ACS”) [Footnote omitted.], more clarity is needed.

The proposed new section 95802(a)(317) defines “resource shuffling” as “any plan, scheme, or artifice undertaken by a First Deliverer of Electricity to substitute electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources to reduce its emissions compliance obligation. Resource shuffling does not include substitution of electricity deliveries from sources with relatively lower emissions for electricity deliveries from sources with relatively higher emissions resources when the substitution occurs pursuant to the conditions listed in section 95852(b)(2)(A).”

As the definition of First Deliverer includes importers (see proposed new section 95802(a)(137)), the applicability of the definition of resource shuffling to electricity imports is fairly clear. However, that clarity becomes a bit muddied in the context of an ACS. As discussed in Powerex’s October 22, 2013 Comments on ARB’s proposed MRR amendments (“Powerex MRR Comments”), some MRR provisions appear to refer to an ACS as itself a specified source, when other definitions recognize that it is the system of an ACS that may be designated as a specified source, and not the ACS entity in and of itself. (See Powerex MRR Comments at 8-10.) The various power transactions that take place within an ACS system would not constitute resource shuffling.

This is because the Program requires an entity that applies for an ACS designation to report annually all transactions for all power generated within its system as well as all transactions for both specified and unspecified power that are delivered to its system. See MRR section 95111(f). Each year an entity applies to be an ACS based on the power generation and import- and-export activity data in the previous year, and ARB then determines its ACS system emission factor prospectively in accordance with MRR section 95111(b)(3). That ACS system EF is applied to power delivered from the system of that ACS in the following year.

During that next year, power delivered by the entity designated as an ACS from its ACS system is reported under the MRR as a specified source with the system EF determined by ARB. To the extent that there may be any questions about the power transactions within an ACS’s system, they are addressed by ARB in the annual ACS application process by which ARB determines the entity’s annual ACS system EF. Should ARB make any changes to an entity’s ACS system EF, those changes would be made prospectively; they would not apply to the year for which the entity had been designated by ARB as an ACS based on its previously submitted reports.[163]

The rationale for the Program's ACS provisions — to ensure environmental integrity through the annual reviews of an ACS system's activity — is particularly clear in the case of a hydropower-based ACS like Powerex. Powerex acts as the exclusive marketer for BC Hydro, which has a fleet of generating sources that is 95% hydro, consisting of more than 30 dams, storage reservoirs and "run-of-the-river" projects within British Columbia.[164] Through its purchasing and marketing activities Powerex optimizes the capabilities of BC Hydro's generation resources, determining the level of power necessary to support BC Hydro's domestic load obligations along with short-term exports to California and imports of both specified and unspecified power. Powerex has historically performed this optimization function for BC Hydro's resources, and continues to do so under California's Cap-and-Trade program. It is a dynamic process, very much affected by weather patterns (temperature and rainfall) and other natural forces. For example, in "high water" years during which there is much precipitation in the Pacific Northwest, Powerex may export more power than it imports, and in "low water" years it may import more than it exports.

All of this optimization activity is fully reported and verified each year in Powerex's annual application for ACS designation, and all of this activity is then captured in its ARB-determined ACS system EF. Given the full, verified reporting inherent in this process and its role in ensuring the environmental integrity of the Program, Powerex respectfully requests that ARB confirm that the definition of "resource shuffling" does not include the activity reported and verified annually as part of the rolling ACS application and ACS system EF determination process.

3. In the event that ARB cannot provide the clarifying confirmations requested above, then Powerex respectfully requests that ARB adopt an additional safe harbor — that is, a new Safe Harbor No. 14, which would apply to the unique circumstances of an ACS. We propose the following language for this new safe harbor:

> Purchase, sale, and scheduling activity associated with the system of an asset-controlling supplier, incorporated into ARB's determination of the asset-controlling supplier's annual system emission factor in accordance with MRR section 95111(b)(3), shall not be considered resource shuffling during the reporting year for which the entity has been designated as an asset-controlling supplier.

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163 ARB confirmed this in the Final Statement of Reasoning for Amendments to the MRR and Conforming Amendments to the CTR, dated November 2, 2012. In response to a comment by the Southern California Public Power Authority expressing concerns about the status of specified power purchased from an ACS that later loses its ACS status, ARB explained that a loss of ACS designation "would only occur if an ACS did not successfully complete the reporting and verification process," and confirmed that "a loss of [ACS] designation would be prospective only, as ACS status would not be revoked retroactively.

164 It should be noted that at least two of these generation stations (G.M. Shrum on the Peace River and Mica on the Columbia River) are large multi-year storage reservoirs. These reservoirs have the ability to store water in one season, and draw on the water in a subsequent season or even years later to run the turbines. Extended draw-downs of water levels in major storage reservoirs in one season may take years to recover from, and adversely affect generation efficiency in every following year until restoration of the original water levels has been completed.

As discussed in Section 1 above, ARB's ACS designation process has resulted in a single, system-wide EF for Powerex's ACS-related transactions with California in 2013. Under ARB's rolling review procedures, a new system EF will be established for each subsequent year. And in each subsequent year Powerex's ACS system EF will be based on its full and verified reporting of the then-prevailing mix of supply inputs to and generation within the BC Hydro system that are required to meet the dynamic operational requirements in each given year, including the support of exports to California.

The very nature of a hydropower system and the optimization activity needed to meet its dynamic operational requirements expose such systems to unjustified claims of inappropriate use of its ACS status. Powerex has availed itself of ARB's ACS process to submit to full review and verification of the entirety of the BC Hydro system inputs, including both imports and in-Province generation, in order to determine a single, ACS system-wide EF. Powerex is committed to providing accurate reporting to ARB due in part to its general responsibilities as a Crown Corporation, but also to protect itself against claims of resource shuffling.

Powerex should be entitled to rely on the applicability of the ACS EF for the particular year that it is in place without fear of retroactive adjustment (again, assuming that Powerex has accurately reported to ARB) or on Safe Harbor No. 10. If ARB cannot clearly provide such a confirmation, then Powerex respectfully submits that it should consider adopting the proposed Safe Harbor No. 14 set forth above. (POWEREX 1)

> **Response:** These comments related to MRR are outside the scope of the proposed 45-day amendments because it does not address specific amendments to the Cap-and-Trade Regulation.

EIM and Resource Shuffling

E-3.62. Comment: 5. ARB's Wholesale Incorporation of the CAISO Energy Imbalance Market Program May Promote Resource Shuffling. On September 23, 2013, CAISO released its "Draft Final Proposal" for Energy Imbalance Markets (the "EIM"). Powerex is actively involved in the development of the CAISO EIM program, and noted in its comments on CAISO's "Third Revised Straw Proposal," which were submitted to CAISO on September 10, 2013 (*see* http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx), that CAISO's carbon proposal remains inconsistent with elements of ARB's Cap and Trade Program. The proposed CTR amendments do not address the inconsistencies between the two programs. In essence, they simply add CAISO's EIM concepts to the definitions of electricity import and export without any revision. If left unaltered, the EIM provisions have the potential to damage the viability of ARB's Cap and Trade Program.

CAISO's approach is designed to efficiently select individual low-EF generators from an EIM participant's portfolio of resources for delivery to the CAISO, while leaving higher-

EF power for deemed delivery to the EIM participant's local load or to other states within the EIM footprint that do not have cap-and-trade programs. This organized, algorithmic approach will systematically prefer the delivery of low-EF power to California and artificially enhance the states' ability to reach its GHG emission reduction goals, while actually promoting leakage in neighboring states. In other words, the EIM overlay to the ARB Program may cause resource shuffling if it fails to consider the GHG impacts of *all* activities that result from EIM price signals - a result which is inconsistent with the purpose of the Program. This discrepancy in results is most readily apparent when contrasted with the approach taken for calculating an ACS's ACS-wide EF and the proposed MRR amendments to address high intensity system power imports. *See* MRR § 95111(b)(5).

The EIM program likely will send powerful price signals to significantly increase resource shuffling not only in the EIM but in the temporal markets that schedule prior to the EIM. EIM participants likely will increase the carbon intensity of their EIM base schedules in order to save low-EF power for the EIM. For example, acting in response to these price signals, an EIM participant with significant coal and natural gas generation likely would increase its reliance on this generation (as well as its reliance on higher-EF imports) to serve its obligations outside the CAISO footprint, as represented by its EIM base schedules, in order to save its lower- EF power, such as hydro-electric output, for the EIM.

The EIM price signals also may create a strong incentive for suppliers to move their transactional activity out of the day-ahead and hour-ahead markets and into the EIM which would allow them access to a substantially more efficient method to capture the value of the low-EF power supply within their portfolios. An EIM participant, through experience, may even seek to build or enter into long-term contracts for higher-EF output to meet its load obligations outside the CAISO so as to "free-up" its lower-EF resources to offer that low-EF power into the EIM on an ongoing basis.

CAISO's carbon algorithm approach in its EIM program proposals has the potential to create market distortions and undermine the mechanisms ARB has established to address the import of system power, including the calculation of ACS-wide EFs for ACSs and ARB's proposed language for "System Power Imports" in MRR § 95111(b)(5). Powerex believes a more appropriate approach, and one that is consistent with ARB's current program design, would be to consider applying either a weighted average emission factor for each EIM Entity (similar to the provisions for calculating the EFs for ACSs and System Power Imports), or, in the alternative, using the unspecified EF for all imports into California in the EIM. Further work would be necessary to evaluate how to apply such non-zero, non-generator specific, emission factors to EIM dispatches in a manner that avoids unintended outcomes in both the energy and carbon markets.

Powerex urges ARB to reconsider the method by which it incorporates CAISO's EIM program into the CTR. In so doing, we recommend that ARB review the more complete set of comments on the EIR that Powerex previously submitted to CAISO. (POWEREX 1)

> **Response:** ARB staff believes the approach to prohibiting resource shuffling and minimizing leakage is not inconsistent with the inclusion of EIM dispatch as a type electricity import that must be included in the regulation.
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> The EIM market will facilitate real time scheduling of intermittent renewable resources such as wind and solar power, which will help California utilities and others meet RPS requirements more cost-effectively.
>
> Not all leakage is resource shuffling. AB 32 requires ARB to design measures to minimize leakage to the extent feasible. The approach included in the 45-day amendments represents the culmination of a multi-year and multi-agency public process that balances minimizing leakage, preventing harm to western electricity markets, and working in harmony with other parts of California's GHG emissions reductions laws, regulations, and policies. Through provisions of safe harbor 10, ARB excludes many kinds of short term transactions from being considered resource shuffling, even if they are based on economic decisions that include consideration of explicit or implicit greenhouse gas costs. EIM transactions fit within this category, and the economic decisions are made by an algorithm that does indeed consider greenhouse gas costs. EIM transactions are part of this larger group of short term transactions which could be the result of multiple decisions by multiple participants in the EIM market.
>
> There are many economic and regulatory drivers for First Deliverers that participate in western electricity markets to engage in various that may or may not be tied to the existence of a Cap-and-Trade Program.
>
> ARB staff has read the commenter's comments to CAISO concerning the EIM. Staff will continue to work with other agencies to monitor EIM to understand better any potential of leakage.

E-3.63. Comment: Finally, we would like to draw staff's attention to the fact that the approach by the CAISO to determine the optimal dispatch of generation from resources participating in the Energy Imbalance Market results in electricity from resources with lower emissions being assigned to California load and electricity from higher emitting resources being assigned outside California. We understand from both the CAISO EIM stakeholder process, as well as CARB's tacit approval of that approach as demonstrated by inclusion of new provisions to address the EIM in the cap and trade regulation, that imports of low-emission power via the EIM would not be considered resource---shuffling. WPTF stipulates that it would be unfair and discriminatory for CARB to consider import of low-emission resources and displacement of high emission resources to be acceptable (not resource shuffling) when it occurs via the EIM, but unacceptable and resource shuffling if it occurs through other markets. (WPTF 1)

Response: ARB staff believes that the EIM dispatch is similar to the dispatch of resources in CAISO markets and would therefore, be included in safe harbor 10. EIM dispatch results from solving a model that is based on programmed economic decisions that include implicit and explicit GHG cost and congestion costs. The model is designed to minimize costs for intra-hour dispatch between multiple balancing authorities, and will help support real-time scheduling of RPS-eligible renewable resources into California. Just as with other transactions contemplated in safe harbor 10, while it is possible that some leakage may occur, this minimal leakage is unavoidable given ARB's multiple goals including the goal to be compatible with reliable electricity markets while minimizing leakage to the extent feasible.

F. OFFSETS AND OFFSET PROGRAM IMPLEMENTATION

F-1. Offset Program Implementation

Authorized Project Designee (APD) Requirements

F.1-1. Comment: Finally, the revised section 95974(a)(2)(B) requires that an Authorized Project Designee (APD) register as an account representative for the CITSS account of an Offset Project Operator (OPO). The Tribe, like many other Offset Project Operators, has multiple offset projects that have various confidentiality and contractual commitments prohibiting the Tribe from including an APD as a CITSS account representative with access to certain project information. Unless CITSS is modified to limit an APD's access to only specific projects, this revision precludes an OPO like the Tribe from having an APD. Rather than bolstering enforcement, it limits ARB's remedies in case of any regulatory violation. The Tribe, like other OPOs, will not be able to use an APD, against which ARB otherwise could have enforced the regulation. Liability is limited to the OPO, which may have had only a small role in developing an Offset Project. This revision reduces ARB's ability to enforce the regulations and hold key parties accountable. (YUROK)

> **Response:** ARB staff disagrees that this provision reduces staff's ability to enforce the regulations and hold key parties accountable. As clarified in the amendments to section 95974(a)(2)(A),the Offset Project Operator (OPO) itself always retains ultimate compliance responsibility. Moreover, individuals who are designated as a Primary Account Representatives (PAR) or Alternate Account Representative (AAR) on the CITSS account associated with the offset project also provide ARB a direct enforcement link between the actions of the individuals on the CITSS account and the offset project activities. The revisions do not remove the ability of OPOs to designate APDs. Ensuring that all APDs are on the CITSS account requires the APD to be subject to the know-your-customer process, and necessitates that all OPOs engage in due diligence when hiring APDs for compliance offset projects.

Issuance of ARB Offset Credits

F-1.2. Comment: Section 95981, Issuance of ARB Offset Credits, has been revised to include additional specificity regarding the mechanics under which an Offset Project Operator or Authorized Project Designee may submit a request for issuance of ARB offset credits. CPEM recommends these provisions be clarified in two respects. First, CPEM understands that, in addition to the Offset Project Operator and Authorized Project Designee, an offset Holder also may initiate a request for issuance of ARB offset credits. This fact should be made clear in the regulations. Second, CPEM understands that, regardless of whether a request is made by an Offset Project Operator, an Authorized Project Designee, or a Holder, circumstances exist in which an entity only desires to have a portion of the eligible credits from a project be issued as ARB Offset Credits. ARB should clarify, and specify the mechanism for, allowing the requesting entity to specify the portion of a project for which offset credits should be issued. (CPM)

Response: In response to the first recommendation to clarify section 95981, the Regulation does not allow holders to initiate the request for issuance of ARB offset credits for projects developed under Compliance Offset Protocols. Therefore, adding this to section 95981 would not be consistent with ARB's current rules for compliance offset projects or the intent of the compliance offset program. The Regulation does, however, allow holders of early action offset credits to request issuance of ARB offset credits. These requirements for holders are already currently in section 95990, which includes the rules for projects participating in the early action program.

In response to the second comment, staff has addressed this in 15-day changes.

Requirements Related to Tribes

F-1.3. Comment: The Yurok Tribe supports the proposed revisions to sections 95975(1)(1) and 95975(h). The Tribe was previously assured that the ARB would not seek punitive or exemplary damages from Tribal governments. The revised section 95975(1)(1) incorporates this assurance in the regulation by reference to California Government Code sections 818 and 818.8. Revised section 95975(h) removes unintentional impediments to Tribal projects due to the need to secure a limited waiver of sovereign immunity. It recognizes that additional time may be necessary to negotiate a limited waiver on a government to government basis with a Tribe and to secure any federal input. While this is not the Tribe's preferred approach, it does largely address the Tribe's concern as to timing of Offset Project listing. (YUROK)

Response: Thank you for the support.

F-1.4. Comment: No change is proposed for section 95973(d). The Yurok Tribe continues to advocate for deleting section 95973(d)(3) in its entirety. It is neither necessary nor appropriate for ARB to require a limited waiver of sovereign immunity for projects on land within Indian lands as defined at 25 U.S.C. §81(a)(1). To the extent a project is implemented within such lands, ARB enforcement is only appropriate against the implementing entity, not a Tribe. (YUROK)

Response: As noted by the commenter, no changes were proposed for section 95973(d). As such, the comment is outside the scope of this rulemaking and no response is required. However, to address the commenter's concerns, staff notes that the requirements are intended to treat offset project operators and offset projects equitably, whether or not on tribal lands. The requirements in section 95973(d)(1)-(3) regarding the limited waiver of sovereign immunity ensures ARB's ability to pursue judicial remedies, if necessary, regarding offset projects located on tribal lands and on lands within the external borders of Indian lands, as defined by 25 U.S.C. §81(a)(1), when enforcing the requirements of the Compliance Offset Protocols and the Cap-and-Trade Regulation. It is ARB's understanding that lands within the external borders of Indian lands, as defined by 25 U.S.C. § 81(a)(1), are subject to sovereignty claims by the Tribe, specifically when such claims arise in the context of the Tribe's exercise of governmental power over the land in question. ARB believes that a limited waiver of sovereign immunity by the Tribe covering all categories of lands in section 95973(d)(1)-(3) is necessary in order to protect the ability of the State to enforce its interest in the proper functioning of the Cap-and-Trade regulation with respect to project operation within the external borders of Indian lands and treats all project developers equally.

Buyer Liability Provisions

F-1.5. Comment: Increase liquidity in offset markets by establishing a registry that links CCO serial numbers to an invalidation guarantee. (BP)

Response: ARB does not offer invalidation guarantees and does not endorse any third-party insurance mechanisms; therefore, ARB staff will not establish a registry for such products. In addition, while staff included provisions allowing Offset Project Registries to provide an insurance mechanism against invalidations, the regulation does not require any parties to offer or use the insurance**.** ARB staff declines to make any serial numbers in the tracking system public as it would potentially decrease the security of the program by allowing individuals to target specific compliance instruments for theft.

F-1.6. Multiple Comments: CLFP opposes the proposed changes to the forestry offset protocol because of the addition of buyer liability to the forestry offset protocol. The forestry industry already has arguably the most burdensome protocol and adding a buyer liability provision will only serve to make these offsets even less desirable to obligated parties. To date, one of the chief attractions of forestry offsets has been the seller liability provision. Increasing the burdens on forestry offsets could make the offset availability in the state much more limited and unattractive.

Comment: WSPA opposes the proposed changes to the forestry offset protocol because of the addition of buyer liability to the forestry offset protocol. The forestry industry already has arguably the most burdensome protocol and adding a buyer liability provision will only serve to make these offsets even less desirable to obligated parties. To date, one of the chief attractions of forestry offsets has been the seller liability provision. Note that offset availability was already limited. Increasing the burdens on forestry offsets could make the offset availability in the state much more limited and unattractive. (WSPA 1)

Response: These provisions will ensure that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Under the existing requirements, an inadvertent loop hole was created, where there was no way to ensure environmental integrity of the program if forestry offsets were used for compliance that were subsequently invalidated, and were not replaced by the OPO within 6 months. Since ARB has clear enforcement authority over covered entities that will be using ARB offsets for compliance, the revisions will ensure overall environmental integrity of the program and equal treatment of all invalidated offset types.

F-1.7. Multiple Comments: We support ARB's existing rule that places responsibility for the invalidation of surrendered forestry offsets on forest owners. This policy is sound because forest owners, not the offset purchasers, are in the best position to assess and manage the three grounds for invalidation: (1) non-compliance with environmental laws; (2) overstatement of the GHG removals; and (3) double registration of the removals. We appreciate ARB's revised Proposed Regulation Order to apply the new liability regime to offsets issued on or after January 1, 2014. While this change is a significant improvement over the original July proposal, it would leave covered entities vulnerable to administrative delay in ARB's issuance process. This is a risk that cannot be controlled in any way by covered entities.

In order to protect the good faith commercial interest of parties enabling offset projects through early stage offtake and financing arrangements (which are desirable to jump start supply), ARB should also protect covered entities that have already entered into contractual arrangements to purchase forestry offsets based on the invalidation parameters in the existing rule. Accordingly, we suggest that ARB apply the new rules to any offset project listed after adoption of the draft regulatory changes.

Summary from Attachment 1: Forestry Offsets Issue: changing liability for the invalidation of forestry offsets would leave covered entities vulnerable to administrative delay in ARB's issuance process and will impact transactions already signed in reliance of the current rule.

Proposed Change: apply new invalidation rule only to forestry projects listed after the date of adoption of the amendments to the regulations.

Proposed Revisions from Attachment 2: Forestry Offsets

§ 95985. Invalidation of ARB Offset Credits

(h) Requirements for Replacement of ARB Offset Credits

(1) If an ARB offset credit that is issued to a non-sequestration offset project or an urban forest offset project, or a U.S. forest offset project that has been listed prior to~~issued on or after~~ ~~January 1, 2014, or~~ the effective date of this regulation, and is in the Retirement Account, and it is determined to be invalid pursuant to section 95985(f) for only the circumstance listed in section 95985(c)(1), then… (CHEVRON 2)

Comment: Section 95985(i): Under the current Regulation addressing the treatment of offset credits for U.S. forest projects, if a covered entity retires a forestry ARB offset credit and thereafter the project is invalidated, the Forest Owner is responsible and the covered entity is still considered to be in compliance, even if it does not have enough valid compliance instruments. The Staff proposes to amend the current Regulation. The Staff asserts that a change to the existing rule is needed to “clarify” that this section only applies to ARB offset credits issued to U.S. forest projects prior to the effective date of these amendments. Staff Report at pp. 277-78. The Staff states that, after the effective date of these amendments, the provisions in section 95985(h) will apply to ARB offset credits issued to U.S. forest projects, meaning that the risk of project invalidation will be shifted to the purchaser of the offset. Id. As currently written, the subsection imposes the obligation to replace the ARB offset credits on the “Forest Owner” if the offset credit is determined to be invalid after retirement of the offset. Entities have relied upon this provision in the negotiation and execution of contracts for the purchase of offsets, and in the allocation of costs and risks under those contracts. The Staff’s proposed change would shift responsibility for “replacement” of offset credits (credits issued prior to the effective date of these amendments) from the Forest Owner to the purchaser of the offset credit, thereby undermining the terms of existing contracts. The Staff has not adequately explained why this subsection should be amended in this manner. The current language provides a clear, understandable assignment of responsibility in the event an offset credit from a forestry project is deemed to be invalid. Reversing direction with respect to the assignment of liability will create uncertainty and will be disruptive to entities with existing contracts.

If the ARB nevertheless decides to adopt the Staff’s recommendation to amend this subsection, the ARB must afford “grandfathered” treatment to contracts that pre-date the effective date of the amended regulations. The Staff’s proposal would only “grandfather” offset credits issued to U.S. forest projects prior to January 1, 2014. See Staff Report at pp. 277-78. Grandfathered treatment should apply to all pre-January 1, 2014 contracts, as well. Parties that relied upon the pre-existing rules at the time they entered into an agreement for the purchase and sale of forest project offsets should continue to be able to rely upon these pre-existing rules for the duration of their contract. (SHELL)

> **Response:** The proposed amendments to the regulation provide consistency of the invalidation rules amongst all offset project types. These provisions will ensure that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Under the existing requirements, an inadvertent loop hole was created, where there was no way to ensure environmental integrity of the program if forestry offsets were used for compliance that were subsequently invalidated, and were not replaced by the OPO within 6 months. Since ARB has clear enforcement authority over covered entities that will be using ARB offsets for compliance, the revisions will ensure overall environmental integrity of the program.
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> In 15-day changes ARB staff changed the proposed date of issuance from January 1, 2014 to July 1, 2014. This should address some of the concerns with retroactively applying these regulatory requirements and ensure that the proposed shift in liability occurs as soon as possible to ensure the environmental integrity of the program. A fixed date will also provide clear rules and certainty to

market participants involved in the offsets program. In addition, the offsets portion of the Cap-and-Trade Program is voluntary and ARB staff does not look at third-party contracts in the context of offsets. Covered entities are not required to use offsets for compliance.

F-1.8. Comment: We have a question about one of the newly proposed provisions regarding double verification of offsets:

95985(b)(1)(B)3. If the [subsequent Offset Project Data Report undergoes the double verification procedure], the ARB offset credits *issued for no more than three Reporting Periods prior to the Reporting Period for which the subsequent Offset Project Data Report was verified* by a different verification body, may only be subject to invalidation…within three years of the date for which ARB offset credits are issued…. We are trying to figure out the purpose of the italicized language. We think this language is meant to answer the question: "which offsets get the benefit of the reduced timeframe for invalidation?" But the reference to reporting periods is confusing because the definition of "Reporting Period" in the regulations refers to the time period during which the GHG reductions/removals took place. Does this language mean that a subsequent verification will only reduce the invalidation timeframe for ARBOCs issued for reductions going back three years? What about early action projects where reductions took place up to 8 years ago – can those be double verified? (CTV)

Response: ARB staff agrees and clarified this language as part of 15-day changes.

New Offset Protocols and Offset Usage Restrictions

F-1.9. Multiple Comments: Chevron supports efforts to increase the availability of offsets. An adequate supply of offsets plays a significant role in containing program costs. Geographic limitations on offset projects, such as those limiting projects to within the US and its territories, substantially increase program costs and may ultimately result in businesses and jobs leaving the state.

Carbon offset project types are limited to those that the California Air Resource Board approves through adoption of protocols. Industry analysts expect the program to need as many as 220 million compliance-eligible offsets. The four protocols that have been approved by ARB will not produce the needed supply for cost-effective compliance options under AB 32's requirements. Recent analysis by the American Climate Registry finds that there will be a significant shortage of offset supply by 29 percent in the first compliance period and up to 67 percent by the third compliance period.

We urge ARB to continue to both develop additional protocols and explore options to streamline its adoption and offset review process. This is particularly important because under the six protocols, adopted and in process, several experts have predicted offset supply shortages.[165] Any ARB efforts to reduce future uncertainty regarding the role of offsets in the program will help boost offset supply, as current uncertainty is holding back offset project investment. (CHEVRON 2)

Comment: We also need to ensure sufficient offsets exist to limit the costs of compliance with the Cap-and-Trade Program for the sake of California's businesses and consumers. As was voted for overwhelmingly by the California Congressional delegation as part of the Waxman Markey legislation and supported by major environmental groups, allowing MMC offsets into the program can help further both important goals. (CE2CAPITAL1)

Comment: In a state-wide Cap-and-Trade Program, like the one developed by the ARB, establishing and enforcing an emissions cap is enough to ensure an environmental goal will be met. In facilitating all potential sources of emission reductions, including offsets, ARB has established a program that can achieve California's GHG emission goals in the most efficient manner. A steady supply of offsets in the California Cap-and-Trade program will help keep allowances prices down in the long-run, thereby moderating compliance costs for California electricity customers. Still, SCE remains concerned that this will not be enough. All the major analyses of the California offset market suggest that offset project developers will fall short of supplying the market's projected demand. The projected shortfall in offset supply remains a troubling problem- one that this proposed MMC protocol attempts to address. (SCE2)

Comment: Expanding offset supply would be an effective means of containing the cost of the cap-and-trade program, while also ensuring environmental integrity of the program. Additional low-cost compliance options could be introduced into the system through offsets in a variety of ways, but first and foremost is ensuring that offset supply meets demand. That can be done through the timely development and adoption of additional compliance offset protocols such as the Mine Methane Capture protocol currently being considered by the Board. Generally, IETA supports ARB’s efforts to develop new protocols that can provide offset credits to supply the market. In addition, we encourage ARB to update and expand existing protocols that can increase supply of already-proven, high-quality offset credits in the near-term. (IETA)

Comment: Please consider Agricultural Orchards as part of the available Carbon Credit program. (MARDEN)

Comment: And we also encourage CARB's offset protocol review and the adoption of additional protocols, which will expand the offsets available and give the natural gas distribution utilities additional tools for reducing greenhouse gas emissions. We believe the use of these high quality offset credits is an effective cost containment measure. (GUG)

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165 Bloomberg Jul 2013: http://bnef.com/Insight/8132 ; Point Carbon Apr 2013: http://eikon.pointcarbon.com/research/northamerica/wci/analystupdates/1.2325891
American Carbon Registry 2012: http://americancarbonregistry.org/acr-compliance-offset-supply-forecast-for-the- ca-cap-and-trade-program

Comment: The Joint Utilities support the adoption of additional offset protocols to provide an adequate supply of offset credits to the Cap-and-Trade market. The use of high-quality offset credits is an effective cost-containment tool and an essential component of a successful Cap-and-Trade program; however without adequate supply, the cost-containment benefit of offset credits will not be fully realized. Additionally, the Joint Utilities support staff in their efforts to review and revise existing protocols, which will help to ensure technical accuracy and program integrity, and to maximize the supply of offsets from existing protocols. (JUC)

Comment: The Utilities support the adoption of additional protocols to provide an adequate supply of offset credits to the Cap-and-Trade market. The use of high-quality offset credits is an effective cost-containment tool and an essential component of a successful Cap-and-Trade program; however without adequate supply, the cost- containment benefit of offset credits will not be fully realized. Offset credit supply is expected to play an even larger role in cost-containment, with the forthcoming linkage of California and Quebec's cap-and-trade programs. One of the Utilities, PG&E, conducted an analysis and found that compliance costs are forecasted to be higher if offset credit supply in California and Quebec is lower. At the same time, several analyses, including PG&E's, indicate that a supply of offset credits equivalent to the 8% Quantitative Usage Limit will not be available in Compliance Periods 2 and 3 unless additional protocols are adopted. Therefore, the Utilities urge ARB to approve the proposed Mine Methane Capture (MMC) and forthcoming Rice Cultivation protocols, which will pave the way for additional offset credit supply.

While the Rice Cultivation protocol is not expected to support the generation of a significant volume of offset credits, its continued development and ultimate approval are important to the adoption of additional agricultural protocols by ARB. Agriculture is a major industry in California and reducing GHG emissions from this sector is important in helping the state meet its longer-term GHG reduction goals. Additionally, the Utilities fully support staff in their efforts to review protocols, and look forward to opportunities for collaboration. For example, the ozone-depleting substances (ODS) destruction protocol was originally developed in 2009. Since then, baseline scenarios have changed for both refrigerants and foam blowing agents, which should be reflected in a revised protocol. The livestock protocol should also be revised to take into account more recent data. Revisions to these protocols in particular are important to ensure technical accuracy, program integrity, and the maximization of supply from existing protocols. (PGE1)

> **Recommendations:** 1) Adopt the Rice Cultivation Protocol by the start of the 2014 growing season. 2) Create a mechanism for offset aggregation in the agricultural offset sector.

<u>Consideration of New Offset Protocols: Rice cultivation and mine methane capture</u>
Offsets are a critical piece of a cap-and-trade market. They can deliver vast economic and environmental benefits for landowners including farmers, ranchers, and foresters who participate in the offset market by implementing emission reduction practices and

generating sellable credits. Offsets have tremendous potential to inspire innovation in these uncapped sectors of the economy that are not directly included in the program. These practices provide high quality, near term reductions in greenhouse gases. In addition to inspiring additional reductions outside capped sectors, offsets allow regulated companies to take advantage of cost effective reductions being made elsewhere in the economy. Thus, even at limited quantities, offsets can reduce the overall compliance costs of cap-and-trade by a significant amount. Reputable projections suggest that a California cap-and-trade program that includes offsets will likely cost less than $20/ton of emissions, while a program without offsets may cost more than $100/ton of emissions. Based on these scenarios, even offsets limited to 8% of obligations can reduce statewide program compliance costs by more than $200 billion between 2013 and 2020[166].

Although CARB has adopted four compliance protocols to date, these protocols are not expected to be able to generate enough credits to ensure full availability under the program.[167] Furthermore, the leading offset registries have undertaken rigorous scientific efforts to develop other high- quality accounting protocols, such as protocols for nitrogen management, restoration of wetlands, and avoided conversion of grasslands. These protocols can generate valuable emission reductions and investments in un-capped sectors.

Specifically on the Rice Cultivation Protocol, CARB has undertaken a detailed and thoughtful review of the existing protocols and considered the concerns of all stakeholders. We strongly encourage CARB to adopt this protocol prior to the start of the 2014 growing season in order to provide a robust signal to farmers that they can receive revenue for changes in their growing practices. (EDF1)

Comment: PG&E supports the adoption of additional protocols to provide an adequate supply of offset credits to the cap-and-trade market. The use of high-quality offset credits is an effective cost-containment tool and an essential component of a successful cap-and-trade program. However, as previously stated in PG&E's comments, without adequate supply, the cost-containment benefit of offset credits will not be fully realized.

With the forthcoming linkage of California and Quebec's cap-and-trade programs, offset credit supply is expected to play an even larger role in cost-containment. PG&E's analysis found that compliance costs are forecast to be higher if offset credit supply in California and Quebec is lower. At the same time, several analyses, including our own, indicate that a supply of offset credits equivalent to the 8% Quantitative Usage Limit will not be available in Compliance Periods 2 and 3 unless additional protocols are adopted. Therefore, PG&E urges ARB to approve the MMC and Rice Cultivation protocols, which will pave the way for additional offset credit supply.

[166] EDF "Cost Containment through Offsets in the Cap-and-Trade Program under California's Global Warming Solutions Act," July 2011. http://www.edf.org/sites/default/files/EDF%20AB%2032offsetsmodelingmemo%20final2_updated_3Jan2012_v2.pdf

[167] America Carbon Registry "Compliance Offset Supply Forecast for California's Cap-and-Trade Program (2013-2020), September 2012. http://americancarbonregistry.org/acr-compliance-offset-supply-forecast-for-the- ca-cap-and-trade-program

While the Rice Cultivation protocol is not expected to support the generation of a significant volume of offset credits, its continued development and ultimate approval are important to the adoption of additional agricultural protocols by ARB. Agriculture is a major industry in California and reducing greenhouse gas (GHG) emissions from this industry is important to helping the state meet its longer-term GHG reduction goals. In parallel to ARB's review of new offset protocols, we understand staff is planning to update existing protocols as needed. We fully support staff in these efforts and look forward to opportunities for collaboration. For example, the ozone-depleting substances (ODS) destruction protocol was originally developed in 2009. Since then, baseline scenarios have changed for both refrigerants and foam blowing agents, which should be reflected in a revised protocol. The livestock protocol should also be revised to take into account more recent data. Revisions to these protocols in particular are important to ensure technical accuracy, program integrity, and the maximization of supply from existing protocols. (PGE2)

Comment: Furthermore, SoCal Gas and SDG&E strongly support the California Air Resources Board's (ARB) efforts to develop new offset protocols to increase offset supply and provide cost containment benefits. As an initial matter, SDG&E and SoCalGas support the following in the Proposed Regulation: Changes to include more offset protocols. (SEMPRA2)

> **Response:** ARB staff has estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has approved—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane capture protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. ARB staff is committed to evaluating additional offset types to ensure sufficient offset supply.

F-1.10. Comment: Next time when you guys allow offset compliance protocols, consider allowing the VCS methodologies, which is a list of verified carbon standard that has off site compliance protocols that are currently being used by other cap and trade programs. I think that we can benefit by having small companies get more from the Cap and Trade Programs instead of giving more money to big multi-million dollar companies. Thank you. (LEE)

> **Response:** In the proposed amendments, staff has proposed to allow two VCS methodologies for mine methane capture to be used under the early action provisions of the program. ARB staff is committed to evaluating additional offset types to ensure sufficient offset supply.

F-1.11. Multiple Comments: Measures that would act to increase supply of compliance instruments over the long term. For example, the ARB could exempt from the offset limit any offsets that provide in-state ancillary environmental benefits similar to actual reductions at capped sector facilities. One way to structure this would be to exempt offsets from the 8% limit if they could prove one or more of the following:

- a direct reduction or avoidance of any criteria air pollutant in California;
- a direct reduction or avoidance any impacts on water quality in California;
- a direct alleviation of a local nuisance within California associated with the emission of odors;
- direct environmental improvements to land uses and practices in California's agricultural sector;
- direct environmental improvements to California's natural forest resources and other natural resources;
- a direct reduction of the need for mitigation of the impacts within California of rising global greenhouse gas emissions. (SMUD2)

Comment: Offset Project Start Date Proposal: When the trigger is reached, the ARB could increase the number of compliance-grade offsets by changing the Offset Project Commencement date established in Sections 95973(a)(2)(B) and (c) of the cap-and-trade regulation to an earlier date.

For example, the Executive Officer could:

a) Commission a third party to obtain and retire high-quality offsets not otherwise eligible to satisfy the compliance obligations of compliance entities;
c) Commission a third party to invest funds in emission reduction projects outside the capped sectors; (SCE1)

Response: These comments are outside the scope of this rulemaking. ARB staff did not include provisions to increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the Cap-and-Trade Program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

F-1.12. Multiple Comments: CCEEB supports the use of high-quality offsets to constrain costs and believes that offsets should only be limited based on quality, not quantity or geography. In the event that the price containment reserve becomes depleted, we ask the board to consider lifting quantitative and geographic limitations as an economic backstop measure.

Economic studies on Cap-and-Trade clearly demonstrate that offsets can be used to contain costs. In some models (most notably those by USEPA, CRS and CRA), program costs are reduced by as much as 40 percent to 80 percent depending on the model and combination of offset. Within California and the nation, studies show that offset projects can provide near-term opportunities for cost-effective, verifiable GHG reductions that deliver long-term, sustained emissions reduction benefits.
Concerns about offsets and localized "hotspots" have been largely addressed by the ARB Co-Pollutant Emission Assessment[168] which found de minimis co-pollutant co-benefits from quantitative and geographic restrictions of offsets. This analysis has dispelled concerns over greater potential increases in co-pollutant emissions as well as assumptions that communities could significantly benefit from additional co-pollutant reductions. As such, there is little reason to limit the use of offsets as a compliance instrument; indeed, offsets provide long-term cost containment and are consistent with efforts to protect the environmental integrity of the program.

Geographic restrictions—in the false hope that substantial local co-benefits will be achieved— runs contrary to the fundamental aim of offsets, i.e., maximizing total GHG reductions (and thus, climatic benefits) by prioritizing the most effective and efficient reduction opportunities. Unwarranted limits only increase California compliance costs, which in turn could prompt economic and emissions leakage. Similarly, needlessly high program costs could erode political support for state climate programs as costs begin to pass through to California consumers and ratepayers.

Besides benefits in California, offsets also encourage adoption of GHG policies in other jurisdictions, particularly in developing economies that use more energy to fuel economic growth. That is, offsets play an important role influencing international leadership on climate change, which is ostensibly the primary goal of AB 32.
In the event that long-term demand for allowances begins to drain the price containment reserve, ARB should act to (1) delegate issuance of ARB offset credits (ARBOCs) to third party registries, (2) adopt additional offset protocols, (3) recognize regional, national and international offset programs, and (4) work with state and regional agencies and other stakeholders to facilitate the development of offset projects in California. Additional supply options should include:

a) Use of additional Climate Action Reserve Protocols;
b) Use of applicable American Carbon Registry approved methodologies
c) Supporting the development of Pilot REDD Projects;
d) Allow use of Climate Action Reserve Landfill Credits generated before 2012;
e) Approve protocols developed by California air districts, as appropriate;

AB 32 implementation is still in a critical stage of regulatory development and ARB should give significant consideration to achieving state goals in a manner consistent with the statute, which clearly enumerates that the policy should, "achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions." (CCEEB)

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[168] Cap-and-Trade Initial Statement of Reasons, Part I, Volume VI, Appendix P, Co-Pollutant Emissions Assessment

Comment: EDF believes that there are two alternatives which are much more desirable from the perspective of environmental integrity than a hard price cap: 1) extending the cap-and-trade program beyond 2020 which would allow for greater borrowing as needed and 2) refilling the APCR as needed with offsets, including sector-based international offsets.

We understand that neither of these additional options for cost containment is available at this time and that both would require significant further policy development. Specifically, with regard to refilling the APCR with international sector-based offsets, EDF would not support this measure until California had considered the environmental rigor of these offsets and had adopted a protocol pursuant to current California law. However, based on findings by the REDD Offsets Working Group (ROW),[169] EDF believes there is a strong possibility that sector-based offsets like REDD (Reducing Emissions from Deforestation and Forest Degradation) may have a role to play in California's cap-and-trade program as envisioned by the current regulation.

Furthermore, existing progress in Acre, Brazil, suggests that REDD credits likely will not face the supply constraints that domestic offset are projected to have.[170] EDF would only support refilling the APCR with offsets if they were sold at the APCR rate rather than the market rate. California could then consider how to use the price premium to further meet the objectives of AB 32. (EDF 1)

> **Response:** This comment is outside the scope of this rulemaking. ARB staff did not include provisions to increase the amount of offsets allowed to be used in the program, whether by increasing the 8 percent limit or allowing offsets to backfill the APCR. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits while still ensuring that GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

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169 REDD Offsets Working Group "California, Acre, and Chiapas partnering to reduce emissions from deforestation: Recommendations to conserve tropical rainforests, protect local communities and reduce state-wide greenhouse gas emissions," July 2013 http://greentechleadership.org/documents/2013/07/row- final-recommendations-2.pdf

170 *See* America Carbon Registry "Compliance Offset Supply Forecast for California's Cap-and-Trade Program (2013-2020), September 2012. http://americancarbonregistry.org/acr-compliance-offset-supply-forecast for the cap-and-trade program; regarding projected shortfall in supply for existing offset protocols. EDF is conducting analysis regarding the potential supply of REDD credits from Acre, Brazil which suggest there should be ample supply of credits to meet California demand if California adopted a REDD protocol from Acre. This analysis is forthcoming and is based on modeling derived from information available from: Amazon Environmental Research Institute (IPAM), "Acre's Progress Towards Jurisdictional REDD" 2012

ARB staff has estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has approved—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane capture protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. ARB staff is committed to evaluating additional offset types to ensure sufficient offset supply. While the regulation provides a framework for the potential acceptance of sector-based offset credits, ARB has not approved the use of any sector-based crediting program and does not currently allow them to be used in the compliance program. When it is appropriate to begin to consider sector-based crediting programs, ARB staff will be analyzing the inclusion of international offsets very carefully. Any inclusion of potential future sector-based offset programs would require a separate rulemaking that includes its own public stakeholder review and a separate regulatory and environmental review process.

F-1.13. Comment: Increase the offset quantitative limit and allow use of international offsets; Allow covered entities that do not use their entire eight percent offset limit to redistribute that unused portion into the market or to other covered entities. This concept has been discussed in several forums between market participants and staff. BP would be happy to share with staff our specific thinking on this topic. (BP)

Response: This comment is outside the scope of this rulemaking. ARB staff did not include provisions to increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. ARB staff did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

While the regulation provides a framework for the potential acceptance of sector-based offset credits, ARB has not approved the use of any sector-based crediting program and does not currently allow them to be used in the compliance program. When it is appropriate to begin to consider sector-based programs, ARB staff will be analyzing the inclusion of international offsets very carefully. Any inclusion of potential future sector-based crediting programs would require a separate rulemaking that includes its own public stakeholder review and a separate regulatory and environmental review process.

F-1.14. Comment: With respect to additional Category A and B measures, SMUD suggests that the ARB include, but not limit consideration to, the following additional measures:

1) Measures to ensure that the allowed 8% of compliance from offsets is fully available to the market, by:
   - Avoiding the loss of this potential if entities do not use their full offset allocation, allowing carryover of the offset limit on an entity-specific basis or by spreading unused amounts over the broader market.
   - Quickly pursuing and adopting new, rigorous offset protocols, and expanding the geographic scope of existing protocols. SMUD has seen market analysis indicating that even with eventual adoption of the proposed new protocol for mine methane capture, and future consideration of adoption of a protocol related to rice cultivation, offset supply (given the current geographic scope of the offset protocols in place) will not be sufficient to provide the full “room” under the 8% offset limit. SMUD encourages the quick adoption of the proposed coal mine methane protocol and refocused effort on developing and adopting additional protocols; including REDD+ protocols. SMUD also recommends consideration of expanding existing protocols to all of North America and beyond if feasible (SMUD notes that geographic expansion to North America is allowed under the Cap-and-Trade regulations without a new rulemaking). (SMUD2)

Response: The regulation requires that offsets account for eight percent of an individual entity's emissions over a compliance period. ARB does not allow the carryover of unused offsets within this time frame in order to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping the quantitative usage limit to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

ARB staff has estimated that if every entity used its allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has adopted—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane capture protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. ARB staff is committed to evaluation additional offset types to ensure sufficient offset supply.

While the regulation provides a framework for the potential acceptance of sector-based offset credits (such as REDD), ARB has not approved the use of any sector-based crediting program and does not currently allow them to be used in the compliance program. When it is appropriate to begin to consider sector-based crediting programs, ARB staff will be analyzing the inclusion of international offsets very carefully. Any inclusion of potential future sector-based offset programs would require a separate rulemaking that includes its own public stakeholder review and a separate regulatory and environmental review process.

F-1.15. Multiple Comments: Offsets are an important cost-containment strategy for AB 32 implementation. Based on research and the experience of other programs, offsets provide a means of reliably reducing greenhouse gas emissions. Offsets, as part of cost-containment, are an important program element to avoid leakage of emissions to other states and countries, and preventing the loss of thousands of jobs.

The AB 32 IG also believes that the proposed regulation needs additional measures to address potential long-term imbalances to allowance supply and demand given the potential for future adverse economic impacts. For example, AB 32 IG supports broader use of offsets, both through increasing the percentage of offsets allowed beyond the current 8% and not imposing arbitrary geographic or other limits on where offsets originate.

Carbon offset project types are already limited to those that the ARB approves through adoption of stringent protocols and the validation of each offset approved for use under AB 32. Industry analysts expect the program to need as many as 220 million compliance- eligible offsets. The four protocols that have been approved by ARB will not produce the needed supply for cost-effective compliance options under AB 32's requirements. Recent analysis by the American Climate Registry finds that there will be a significant shortage of offset supply by 29 percent in the first compliance period and up to 67 percent by the third compliance period.

Further, the AB 32 IG supports the removal of the offset limit, which inhibits investment in offset programs and undermines the very goal of AB32, which is the reduction of CO2 emissions. (AB32IG)

Comment: Resolution 12-51 does not require ARB to further reduce the probability of an already unlikely event by modifying other aspects of the rule (e.g., by modifying offset usage limits, crediting periods, or eligible geographic scope, as some stakeholders have proposed), which could end up creating more problems than it solves. (NRDC2)

Response: This comment is outside the scope of this rulemaking. ARB staff did not include provisions to increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits while ensuring that GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

ARB has estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has adopted—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane capture protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. ARB staff is committed to evaluating additional offset types to ensure sufficient offset supply.

F-1.16. Multiple Comments: Further, to send a clear signal and offer the greatest impact on cost containment, the offset trigger measures in the second element of the Joint Utilities Group proposal should be implemented immediately, rather than require a trigger event before being implemented.[171] (CHEVRON 2)

Comment: TID supports the changes to the offset provisions to include two new offset protocols and streamlining of the offset project review process. The Coal Mine Methane Capture Protocol (MMC), in particular, represents a major supply of emissions reductions that are sorely needed. A recent analysis by Ruby Canyon Engineering estimates that MMC project have the potential to provide 28 million tons of carbon reductions.[172] Existing offset supply is woefully short of demand and is lacking liquidity, which is diminishing the cost containment effectiveness of the offsets market in general. Compliance entities like TID have been hesitant to enter in to the offsets markets as the risks are outweighing the reward. TID believes that more should be done to increase demand for offset projects. Reducing offset use restrictions will not only help contain costs consistent with Resolution 12-51, but also drive more robust offset market with greater opportunities for new, economic growth. As noted in Dr. Brian Murray's presentation at the June 25th workshop, the ARB should take into account both time and space considerations of GHG emissions when evaluating the environmental integrity objectives in Board Resolution 12-51. Dr. Murray asserts that for GHG emissions, time (when the emissions occur) matters, but not that much within a ten year period.[173] Dr. Murray also asserts that space does not matter because GHG emissions

171 http://www.arb.ca.gov/cc/capandtrade/meetings/062513/industry-present.pdf
172 http://www.arb.ca.gov/cc/capandtrade/protocols/mmc/rce_amm_protocol.pdf
173 See Dr. Murray's June 25th presentation, at Slide 2, available at: http://www.arb.ca.gov/cc/capandtrade/meetings/062513/brian-murray-presentation.pdf.

produced in California have the same impact on the overall concentration of GHG emissions as the same amount of emissions produced elsewhere in the world.[174] When evaluating cost-containment mechanisms, the Cap-and-Trade Regulations should reduce time and space restrictions related to the use of offsets. Such time and space restrictions do not further the environmental objectives of the program. However, removing offset use restrictions will bolster the existing cost containment mechanisms and also further the policy goals of AB 32. One of the legislature's findings in adopting AB 32 was that: investing in the development of innovative and pioneering technologies will assist California in achieving the 2020 statewide limit on emission of greenhouse gases established by this division and will provide an opportunity for the state to take a global economic and technological leadership role in reducing emissions of greenhouse gases.[175]

AB 32 goes on to direct the State Air Resources Board to: design emissions reduction measures to meet the statewide emissions limits for greenhouse gases… in a manner that… maximizes additional environmental and economic co-benefits for California….[176] The development of a more robust offset market will further these AB 32 objectives. Specifically, the ARB should adopt JUG's 2013 revisions to offset rules, which include: (1) allowing the regulated entities to carry over all of the unused portion of the 8% offset restriction on an annual, quantitative basis; (2) exempting California-originated offset projects from the 8% limit; (3) allowing compliance grade offsets to be sourced from anywhere in North America; and (4) moving the offset project commencement to an earlier date. Specific language revisions to implement these objectives are attached hereto as "Attachment A."

In addition, regulated entities should be allowed to trade any unused portion of their offset limitations with other regulated entities. The ARB should incorporate these mechanisms into the Cap-and-Trade program as set forth in Attachment A. Offset projects can take years to develop and sending signals now that there will be higher demand for offset credits in the future will encourage near term investment in new offset projects. (TID 1)

> **Recommendation in Attachment A:** § 95854. Quantitative Usage Limit on Designated Compliance Instruments--Including Offset Credits
>
> (a) Compliance instruments identified in section 95820(b) and sections 95821(b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.
>
> (b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation for a compliance period must conform to the following limit:

[174] *Id.*
[175] See, Cal. Health and Safety Code Sec. 38501(e).
[176] See, Cal. Health and Safety Code Sec. 38501(h).

O[o]/S must be less than or equal to Lo
In which:

O[o] = Total number of compliance instruments identified in section 95854(a) submitted to fulfill the entity's compliance obligation for the compliance period.
S = Covered entity's compliance obligation.

L[o] = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.

(c) The number of sector-based offset credits that each covered entity may surrender to meet the entity's compliance obligation for a compliance period must not be greater than 0.25 of the L[o] for the first and second compliance periods and not more than 0.50 of the L[o] for subsequent compliance periods.

(d) A covered entity may apply to the Executive Officer for an increase in the Quantitative usage limit if it did not use a portion of its allowable offset usage limit in a previous triennial compliance period or another covered entity has agreed to transfer its offset usage limit from a previous or current compliance period. If approved by the Executive Officer, the covered entity’s compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation for a compliance period must conform to the following limit:

O[o]/S must be less than or equal to Lo
In which:

O[o] = Total number of compliance instruments identified in section 95854(a) submitted to fulfill the entity's compliance obligation for the compliance period.

S = Covered entity's compliance obligation.

L[o] = Quantitative usage limit on compliance instruments identified in section 95854(d), set at 0.08 + L[o](unused) + L[o](transferred)

L[o](unused) = The unused portion of the entity’s quantitative usage limit from a previous compliance period. L[o](unused) may not exceed .08% in the second compliance period, and 16% in the third compliance period.

L[o](transferred) = The unused portion of another entity’s quantitative usage limit, expressed as a percentage, and that has been approved for transfer by the Executive Officer. The transferring entity must have a total compliance obligation that is greater or equal to the transferee’s compliance obligation.

Response: ARB did not propose changes to section 95854, so this comment is outside the scope of this rulemaking. The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. ARB does not allow the carryover of unused offsets within this time frame in order to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

F-1.17. Multiple Comments: Specifically, SCE suggests that the ARB:

a) Approve more offset protocols to increase the supply of offsets.
b) Exempt offsets from projects within California from the 8% offset limit.
c) Allow each covered entity to carry over any unused portion of its 8% offset limit to use for future compliance.

Unused Offset Proposal: Currently, a compliance entity is limited in its use of offsets to 8% of its compliance obligation per compliance period. Under the Unused Offset Proposal, when the trigger is reached, the ARB would calculate the program-wide shortfall of unused offsets from earlier compliance periods, and allow compliance entities to apply the difference to later compliance periods. This in effect will increase the quantitative usage limit for entities in a single compliance period, thus reducing upward price pressure on allowances in the short term, while maintaining the quantitative usage limit over the entire term of the program.

Offset Geographic Scope Proposal: When the trigger is reached, the ARB could increase the number of compliance-grade offsets by expanding the geographic scope of the approved offset protocols to North America. (SCE 1)

Comment: For the first category of cost containment measures, the proposals by the Joint Utilities in the paper presented at the June 25, 2013 workshop include:

- Approve more offset protocols to increase the supply of offsets.
- Exempt offsets from projects within California from the 8 percent offset limit.
- Allow each covered entity to carry over any unused portion of its 8 percent offset limit to use for future compliance.

For the second category of cost containment measures, in addition to the mechanism currently proposed in section 95913(f)(5), measures proposed by the Joint Utilities include:

- <u>Unused offset proposal</u>: The ARB would track the number of offsets used for compliance (cumulatively) compared to the number of offsets that would have been used if every covered entity exhausted its 8 percent limit. The difference between the two numbers would be the “8 percent offset shortfall.” Each covered entity would be given the option to register through the tracking system to receive a proportional share of the 8 percent offset shortfall if the trigger is reached. The registration process ensures that only the entities that are interested in procuring additional offsets are given the ability to do so. Entities that do not register would remain subject to the 8% limit. When the trigger is reached, the ARB would distribute rights to use additional offsets among the registered entities up to the 8 percent offset shortfall in total. The new offset limits for those entities would be calculated to ensure that, if all registered entities surrender offsets up to the new higher level, the 8 percent offset shortfall would be used up but not exceeded. If the 8 percent offset shortfall is not exhausted in that compliance period, a new offset level would be calculated for the registered entities for the next compliance period.[177]

- Offset geographic scope proposal: When the trigger is reached, increase the number of compliance-grade offsets by expanding the geographic scope of the approved offset protocols to North America.
- Offset project start date proposal: When the trigger is reached, increase the number of compliance-grade offsets by changing the Offset Project Commencement date in sections 95973(a)(2)(B) and (c) of the Regulation to an earlier date. (SCPPA 1)

Comment: The other issue I'd like to comment on is with respect to the cost containment provisions. One of the things that we've advocated for in our written comments is an expansion of the offset rules. And we agree certainly with the inclusion of new offset protocols. But the other side of the equation is how to encourage offset demand. And specifically, the eight percent offset usage limit we believe should be expanded such that an entity can bank that going forward. That would send a market signal in the near term as to the potential demand for offsets in the later parts of the program. (TID 2)

Response: Since ARB did not propose any revisions to section 95854 as part of this rulemaking, any changes to the 8 percent limit or banking of the 8 percent limit are outside the scope of this rulemaking. ARB staff has estimated that if every entity used its allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has adopted—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane capture protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. ARB staff is committed to evaluating additional offset types to ensure sufficient offset supply.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. ARB did not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total

[177] The distribution mechanism that is proposed here is revised from the Joint Utilities proposal.

emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

F-1.18. Comment: Aside from the adoption of additional protocols, two relatively simple options to increase the effectiveness of offsets as a cost containment mechanism are: 1) expand entity compliance limits beyond 8%; or 2) allow entities to carry over unused offset limits from one compliance period to the next. (IETA)

Response: Since ARB did not propose any revisions to section 95854 as part of this rulemaking, any changes to the 8 percent limit or banking of the 8 percent limit are outside the scope of this rulemaking. ARB staff did not include provisions to increase the amount of offsets allowed to be used in the program. The program imposes a limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. ARB does not allow the carryover of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

F-1.19. Multiple Comments: For example, CLFP supports broader use of offsets, both through increasing the percentage of offsets allowed beyond the current 8% and by expanding the offset supply. These options were discussed at the June 25th Workshop.

CLFP supports acceptance of valid national and international offsets and allowances as such linkage would provide environmental benefits while controlling costs and potential adverse economic impact on the state's economy. CLFP also supports the removal of the offset limit, which inhibits investment in offset programs and undermines the very goal of AB32, which is the reduction of CO2 emissions.
Among the offset proposals we believe that there is substantial merit to the following:

- Allowing compliance entities to carry over offsets between compliance periods
- Redistributing unused offsets back to compliance entities, and
- Improving the potential supply of eligible offset projects both geographically and

by changing the project commencement date

These proposals recognize the important role offsets can play to reduce unnecessary upward pressure on allowance prices and prevent depletion of the allowance price containment reserve while meeting the environmental goals of the program.
ARB should further study other means of increasing the supply of compliance instruments, such as offset carryover across compliance periods, the redistribution of unused offsets, and widening the offset market geographically and temporally. (CLFP 1)

Comment: For example, WSPA supports broader use of offsets by expanding the offset supply. Several options were discussed at the June 25th Workshop both by the panel of economic experts and in a proposal developed by the Joint Utilities Group. We believe that of the options discussed by the economic experts, adding the indirect linkage through acceptance of valid national and international offsets and allowances would provide the environmental benefits while controlling costs and potential adverse economic impact on the state's economy. WSPA also supports the removal of the offset limit, which inhibits investment in offset programs and undermines the very goal of AB32, which is the reduction of CO_2 emissions.

Among the offset proposals we believe that there is substantial merit to the following:
- Allowing compliance entities to carry over offsets between compliance periods
- Redistributing unused offsets back to compliance entities, and
- Improving the potential supply of eligible offset projects both geographically, as mentioned above and by changing the project commencement date (WSPA 1)

Response: Since ARB did not propose any revisions to section 95854 as part of this rulemaking, any changes to the 8 percent limit or banking of the 8 percent limit are outside the scope of this rulemaking. The regulation requires that offsets account for eight percent of an individual entity's emissions over a three-year period. ARB does not allow the carryover of unused offsets or redistribution of unused offsets within this time frame to ensure that emission reductions are being achieved by capped sources throughout the life of the program. Keeping it to the compliance period allows some flexibility by giving three years to total emissions, but still requires that emission reductions are coming from within capped sectors in all years of the program.

While the regulation provides a framework for the potential acceptance of sector-based offset credits, ARB has not approved the use of any sector-based crediting program and does not currently allow them to be used in the compliance program. When it is appropriate to consider international sector-based crediting programs, ARB staff will be analyzing the inclusion of international offsets very carefully. Any inclusion of potential future sector-based offset programs would require a separate rulemaking that includes its own public stakeholder review and a separate regulatory and environmental review process.

Early Action

F-1.20. Comment: New Section 95990(e)(2)(G) specifies that, for early action offset projects developed under the Climate Action Reserve U. S. Ozone Depleting Substances Project Protocol version 1.0, each reporting period, and/or each destruction event may be considered an independent project. CPEM requests clarification that such projects also may be listed as a single project, with multiple reporting periods. CPEM recommends the draft language be revised as follows: "For early action offset projects developed under the Climate Action Reserve U. S. Ozone Depleting Substances Project Protocol version 1.0, each reporting period, and/or each destruction event may either be considered an independent project or may be listed as a single project with multiple reporting periods. (CPM 1)

> **Response:** ARB staff agrees and included additional language in the 15-day changes to address this concern.

General Comments about Offsets

F-1.21. Multiple Comments: ARB should minimize carbon offsets that could diminish direct emission reductions in disadvantaged communities. (GAIA)

Comment: ARB should minimize carbon offsets that could diminish direct emission reductions in disadvantaged communities. (APEN)

> **Response:** Since ARB did not propose any changes to the quantitative usage limit in section 95854 as part of this rulemaking, this comment is outside the scope of the rulemaking. The program imposes what ARB staff believes is an appropriate limit on the amount of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits and ensures that some GHG emissions reductions occur within the sectors covered by the cap-and-trade program. The program includes provisions that would allow a maximum of a little over 200 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.
>
> ARB staff analysis indicates that the Cap-and-Trade Regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics. Based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, staff believes that emission increases due to the regulation at the statewide, regional, or local level are extremely unlikely, at best.

F-1.22. Comment: Offsets do not offer a reliable solution to emissions reductions, and are in fact a significant liability and loophole to achieving real, additional, and permanent reductions. The primary interest in offsets is their potential to make it *easier* and *cheaper* for polluters to meet emissions reduction requirements. This is because they cost less per credit than emissions credits.

However, even though they cost less than an emissions credit, the non-monetary costs are not reflected in the price. Offsets allow pollution to continue at the source, creating pollution hot spots that cause significant public health and environmental costs for nearby communities. The point of reducing emissions is not to cater to polluters, but rather to reduce emissions and deter future emissions—offsets achieve neither.
In reality offsets are not comparable to direct emissions reductions. They actually allow companies to pay to continue polluting at the source, while an emissions reduction supposedly occurs elsewhere.

Allowing companies to pay to pollute does very little to discourage or decrease emissions in the present and in future generations. Even the U.S. Government Accountability Office (GAO) points out that, "In theory, offsets allow regulated entities to emit more while maintaining the emissions levels set by a cap and trade program or other program to limit emissions."[178]

Offsets also risk causing increased emissions. Several verification requirements must be met for an offset to be valid, but it is very hard to meet all of the requirements. This creates opportunities for fraud, corruption and minimal emissions reductions—if not increased emissions—because of illegitimate offsets that are still released into the market.[179] A company in California could purchase an offset elsewhere that might not create an emissions reduction, leading to a net increase in emissions because the company continues to pollute at the source.

Offsets can also take a long time to create, but the credits for offsets are in demand now. The remedy to this has been to create systems of forward crediting and forward selling. Forward crediting requires allocating an offset before it can have produced the expected emissions reduction.[180] This form of "I-owe-you" offset is another liability and leaves the door open to the possibility of no emissions reduction and even increased emissions.

The societal and environmental impacts of offsets are not to be overlooked either. They allow emissions to continue at the source of pollution instead of reducing it directly, creating toxic hot-spots—something California is not new to, considering their experience with hot spots in Los Angeles from Rule 1610 in the early 1990's.

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[178] Gilbertson, Tamra and Oscar Reyes. Dag Hammarskjöld Foundation. "Carbon Trading: How it works and why it fails." *Critical Currents*, no. 7. November 2009 at 11.

[179] U.S. Government Accountability Office (GAO). "Climate Change Issues: Options for Addressing Challenges to Carbon Offset Quality." (GAO-11-345). February 2011 at 8.

[180] Pew Center on Global Climate Change. "Greenhouse Gas Offsets in a Domestic Cap-and-Trade Program." Fall 2008 at 10.

However, unlike what happened with Rule 1610, the hot spots from offsets would not be limited to just Los Angeles, they would become a statewide problem. Environmental justice is a serious concern for the communities subjected to hot spots. Often times the areas burdened with these high concentrations of pollution are made up of low- income populations and people of color.[181] In addition, hot spots create public health impacts and are linked with respiratory and cardiovascular health problems. Not to mention that the persistent pollution in these areas continues to degrade the environment, especially air and water quality. (FWW)

Response: Since ARB did not modify the quantitative usage limit in section 95854, or the ability of entities to utilize approved offsets up to that quantitative usage limit as part of this rulemaking, this comment is outside the scope of this rulemaking. ARB staff disagrees with the commenter that the inclusion of offsets does not require capped sources to reduce emissions. The program imposes what staff believes is an appropriate limit on the amount of offsets that an individual covered entity can use for compliance. And contrary to the commenter's contention, all offsets eligible for use for compliance in the Cap-and-Trade Program represent real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits while ensuring that GHG emissions reductions occur within the sectors covered by the Cap-and-Trade Program. The program includes provisions that would allow a maximum of a little over 200 $MMTCO_2e$ of offsets through the year 2020. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation, or total emissions. Combined with the Allowance Price Containment Reserve, this limit ensures that reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

ARB staff's analysis indicates that the cap-and-trade regulation is expected to have a beneficial impact on air emissions by reducing emissions of criteria pollutants and toxics. Based on the available data, current law and policies that control industrial sources of air pollution, and expected compliance responses, staff believes that emission increases due to the regulation at the statewide, regional, or local level are extremely unlikely. Nevertheless, ARB staff is committed to monitoring the implementation of the cap-and-trade regulation to identify any situations where the cap-and-trade program has led to an increase in criteria pollutant or toxic emissions. This information will be used to identify compliance activities that could lead to increased emissions, and to determine whether further investigation of potential criteria pollutant and toxic emissions is warranted. If unanticipated adverse localized emissions impacts that can be attributed to the cap-and-trade regulation are identified during this periodic review, ARB staff will consider whether these impacts affect the achievement of the program objectives.

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[181] Drury, Richard Toshiyuki, et. al. "Pollution Trading and Environmental Injustice: Los Angeles' Failed Experiment in Air Quality Policy." Duke Environmental Law & Policy Forum, Vol. 9 Issue 231. Spring 1999 at 251.

In response to forward crediting and forward selling, ARB does not allow forward crediting for offset projects. ARB offset credits are only issued once the GHG reduction or removal enhancement has occurred and been verified by an ARB-accredited third-party verification body pursuant to the rigorous verification requirements in the Cap-and-Trade Regulation.

In addition, ARB has full enforcement and oversight authority over all offset project developers, offset verifiers and verification bodies, and Offset Project Registries. ARB can disallow offset issuance to a project developer, revoke or suspend the accreditation of ARB-accredited verifiers, and revoke or suspend the approval of Offset Project Registries. In addition, the regulation requires all users of offset credits to replace them to ARB in the event they are found to be invalid after issuance.

F-1.23. Comment: Finally, Chevron is also concerned that ARB continues to introduce additional administrative requirements in the offset program. Chevron supports high quality offsets. We urge ARB to streamline the administrative process and would be happy to work with staff to identify specific opportunities. (CHEVRON2)

Response: Intensive review and scrutiny of all offset project documentation by ARB staff is required to ensure that all GHG reductions or removal enhancements credited as offsets meet the AB 32 criteria and to minimize any risk of invalidation in the future. ARB staff believes that the administrative requirements in place for project processing and review is adequately rigorous to ensure that the offsets program provides overall environmental integrity to the Cap-and-Trade Program.

F-1.24. Comment: The new sentence in the definition of "Qualified Positive Offset Verification Statement" should be clarified. A new sentence is proposed to be added to the definition of "Qualified Positive Offset Verification Statement" in section 95802(a)(292) of the Regulation:

Non-conformance, in this context, does not include disregarding the explicit requirements of this article or applicable Compliance Offset Protocol and substituting alternative requirements not approved by the Board.
It is unclear from this new sentence how such disregard and substitution would be treated, if they do not constitute a non-conformance. It would seem that such actions should constitute a non-conformance. This sentence should be revised for clarity.
The Initial Statement of Reasons prepared for the proposed amendments to the Regulation, dated September 4, 2013 ("ISOR"), provides a helpful description of the purpose of this change:

This modification is necessary to clarify that the qualified positive offset verification statement is not allowed when the offset project operator or authorized project designee substitutes an explicit requirements of the Regulation with a method not approved by the Board.[3]

This should be reflected in the Regulation, as the currently-proposed drafting does not clearly reflect this position.

> **Recommendation:** SCPPA's proposed changes to section 95802(a)(292) are set out below:
>
> (292) "Qualified Positive Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement.~~, but~~ tThe Offset Project Data Report may include one or more nonconformance(s) with the quantification, monitoring, or metering requirements of this article and applicable Compliance Offset Protocol which do not result in an offset material misstatement. However, a qualified positive offset verification statement cannot be provided if the offset project operator or authorized project designee ~~Non-conformance,~~ ~~in this context, does not include~~ disregardeding the explicit requirements of this article or applicable Compliance Offset Protocol and substituteding alternative requirements not approved by the Board. (SCPPA 1)
>
> **Response:** ARB staff agrees and clarified this language in 15-day changes.

F-1.25. Comment: Creation of Mechanism for Offsets Aggregation in the Agricultural Sector: As the largest uncapped sector of California, agriculture presents a significant opportunity to generate valuable greenhouse gas emission reductions. As stated above, EDF applauds CARB's development of the Rice Cultivation Protocol.
For agricultural offset projects to be effective though, farm-level reductions need to be aggregated into larger, multi-landowner projects. Aggregation is one of if not the most important factor in the development of agricultural offset projects that are cost-effective and allow for the engagement of the agricultural sector in California's cap-and-trade program.

EDF encourages CARB to adopt future modifications to the cap-and-trade regulations which allow for the aggregation of agriculture offset projects. Several organizations, including EDF, have developed and provided recommended edits to the regulations. CARB should consider these edits as a part of the adoption of the Rice Cultivation Protocol early next year. Without inclusion of aggregation rules, widespread adoption of offset projects from the agricultural sector will be extremely difficult. EDF looks forward to continued discussions and providing feedback to CARB on this important issue. (EDF 1)

> **Response:** This comment is outside the scope of this rulemaking. A rice cultivation protocol is not including in this rulemaking and any comments related to this protocol would be considered and addressed during the public process

associated with the evaluation of that protocol and any potential rulemaking to add the protocol to the Cap-and-Trade Regulation. Regardless, all new protocols and any modifications to the structure of the existing offsets program must ensure that the resulting offsets continue to meet the AB 32 offset criteria.

G. COMPLIANCE OBLIGATION SURRENDER

G-1. General

G-1.1. Comment: Business fluctuations at the end of a compliance period are anticipated. These fluctuations could adversely impact the smooth operation of the market. CCEEB recommends that current vintage allowances (i.e. borrowing from the current year) be allowed during the true-up period (i.e. the time between the end of a compliance period and when that compliance period's obligation is due). This will provide a mechanism for end of compliance period truing-up that will increase market confidence. (CCEEB 1)

> **Response:** ARB staff does not agree with the comment. Compliance instrument obligations are due in November following the year of compliance. As such, entities will have sufficient time to acquire compliance instruments prior to the November surrender events. In addition, the purpose of the true-up is to correct for allowances incorrectly accounted for in prior allocations based on estimates of production. Entities receiving true-up allowances will be able to use current calendar year's vintage allowances and allowances allocated just before the annual surrender deadline up to the true-up allowance amount. As such, staff believes the true-up provisions proposed ensure a smoothly operated market and no further changes are needed.

G-2. Compliance Instrument Retirement Order

G-2.1. Multiple Comments: Revise drafting in section 95856 and avoid using the inaccurate term "surrender": SCPPA supports the changes to sections 95856(g) and (h) that remove the retirement of compliance instruments for the annual compliance obligation, replacing it with an evaluation of the number and type of compliance instruments in each covered entity's compliance account. However, given this change, it is inappropriate to continue using the term "surrender" in relation to meeting compliance obligations. The word "surrender" indicates that an action must be taken by the covered entity, such as retiring or moving compliance instruments, or nominating compliance instruments to be retired. But no such steps are necessary. The covered entity merely needs to ensure it has sufficient valid compliance instruments in its account on each compliance deadline. The ARB takes all other steps that need to be taken – evaluating (for the annual deadline) or retiring (for the triennial deadline) the compliance instruments. The word "surrender" does not adequately describe this situation. References to "fulfilling" compliance obligations would be more appropriate; this term is already used in some parts of section 95856. (SCPPA 1)

Comment: Rather than specify the order in which compliance instruments are removed from an entity's compliance account for retirement, as proposed in the Discussion Draft, section 95856(g) of the Proposed Amendment would not have compliance instruments retired in each annual review, but rather merely "determine the status of compliance with the annual compliance obligation by evaluating the number and types of compliance instruments in the Compliance Account." (NCPA 1)

Comment: WPTF appreciates staff modification of the regulatory provisions regarding retirement of compliance instruments in section 95856. In particular, we support the proposal to eliminate the annual retirement of compliance instruments and instead provide for annual evaluation of whether each covered entity has sufficient instruments in its compliance account. (WPTF 1)

Comment: Section 95856(h)(1) provides that the Executive Officer will determine compliance with the annual compliance obligation by evaluating the number and type of compliance instruments in the compliance account in the following order: offsets, Reserve allowances, normal allowances, true-up allowances. However, it is unclear why the order needs to be specified for the annual compliance obligation, as the instruments are not actually being retired, just counted. As long as they are valid (i.e. come from the correct vintage), there is no need to count the instruments in any particular order. Establishing an order is necessary only when retiring instruments for the triennial compliance obligation.

Section 95856(f)(3) provides that the number of compliance instruments required for the triennial compliance obligation equals the triennial compliance obligation calculated pursuant to section 95853 less compliance instruments surrendered to fulfill the annual compliance obligation for the years in the compliance period. This section should be revised to reflect the fact that compliance instruments will no longer be retired for the annual compliance obligation.

SCPPA's proposed changes to section 95856 are set out below:

> § 95856. Timely Fulfillment~~Surrender~~ of Compliance Obligations~~Instruments~~ by a Covered Entity.
>
> (b) Compliance Instruments Valid to Fulfill Compliance Obligations~~for~~ ~~Surrender~~.
> …
> (d) Deadline for Fulfillment~~Surrender~~ of Annual Compliance Obligations. For any year in which a covered entity has an annual compliance obligation pursuant to section 95855, it must fulfill that obligation: …
> …
> (f) FulfillmentSurrender of Triennial Compliance Obligation.
> …
>
> (2) The total number of compliance instruments that may be used~~submitted~~ to fulfill the triennial compliance obligation is subject to the quantitative use limit pursuant to section 95854.
>
> (3) The number~~surrender~~ of compliance instruments in the compliance account must be equal to or greater than the triennial compliance obligation calculated pursuant to section 95853 ~~less compliance~~ ~~instruments~~

~~surrendered to fulfill the annual compliance obligation for the years in the compliance period~~.

…

(g) In determining whether the covered entity has fulfilled its compliance obligations, the Executive Officer shall:

(1) In the case of annual compliance obligations, ~~determine the status of compliance with the annual compliance obligation by~~ evaluat<u>e</u>~~ing~~ the number and types of compliance instruments in the Compliance Account <u>in accordance with section 95856(h)(1);</u> and

(2) In the case of triennial compliance obligations:

(A) Retire ~~the~~ compliance instruments<u> in accordance with section 95856(h)(2)</u>~~surrendered~~; and …

(h) Annual and Triennial Compliance Instrument Requirements

(1) ~~When a covered entity or opt-in covered entity surrenders compliance instruments to meet its annual compliance obligation pursuant to section 95856(d), t~~<u>T</u>he Executive Officer will determine <u>a covered entity's or opt-in covered entity's</u> compliance with the annual compliance obligation by evaluating the number and type of compliance instruments in <u>its</u>~~the~~ ~~C~~<u>c</u>ompliance ~~A~~<u>a</u>ccount ~~in the following order~~ and ensuring there are enough <u>valid</u>~~eligible~~ compliance instruments to cover the annual compliance obligation.~~:~~

~~(A) Offset credits specified in section 95820(b) and sections 95821(b) through (d) without consideration of the quantitative usage limit set forth in section 95854;~~

~~(B) Allowances purchased from an Allowance Price Containment Reserve sale or compliance instruments pursuant to section 95821(f)(1);~~

~~(C) Allowances specified in section 95820(a), and 95821(a); and~~

~~(D) The current calendar year's vintage allowances and allowances allocated just before the annual surrender deadline up to the True-up allowance amount as determined in sections 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1) if an entity was eligible to receive true up allowances pursuant to sections 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1).~~

(2) ~~When a covered entity or opt-in covered entity surrenders compliance instruments to meet its~~ <u>After each</u> triennial compliance obligation <u>deadline</u>

pursuant to section 95856(f), the Executive Officer will retire <u>a covered entity's or opt-in covered entity's compliance instruments</u>~~them~~ from <u>its</u>~~the~~ <u>c</u>~~C~~ompliance <u>a</u>~~A~~ccount in the following order: …

(3) An entity that is not eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1), cannot use the current calendar year's vintage allowances or allowances allocated just before the current <u>compliance obligation</u>~~surrender~~ deadline to meet the timely <u>fulfillment</u>~~surrender~~ of compliance <u>obligations</u>~~instrument~~ requirements in section 95856. (SCPPA 1)

Comment: While this regulatory change may address the earlier-specified concern, it creates another issue: covered entities may now be more stressed by their holding limits. Under the current regulatory framework, the total holdings of a compliance entity would decrease each year (as ARB retired compliance instruments equivalent to 30% of the entity's prior year emissions). With the proposed elimination of the annual retirement, the entity's account holdings would continue to increase throughout the compliance period (except in the year following a triennial surrender). The relatively greater volume of compliance instruments an entity must hold at any given time means that some entities may be forced to adjust their compliance strategies so as not to exceed their holding limit and limited exemption, resulting in potentially lower market liquidity and trading opportunities. (SCE 1)

Comment: Timely Surrender of Compliance Obligations (S95856): WSPA has identified a series of issues in Section 95856. We highlight them below.

Issue 1: The proposed amendments to sections 95856 (g) and (h) eliminate the requirement for the Executive Officer to retire an annual compliance obligation, and replace it with a review by the Executive Officer to determine if there are sufficient compliance instruments to cover an annual compliance obligation. The new proposal will result in the allowances being kept in the entity's compliance account for the entire compliance period and counted against the limited exemption, instead of being moved to the program's Retirement Account. This will further restrict covered entities from market flexibilities.

Recommendation: Keep the current rule language requiring the Executive Officer to retire compliance instrument surrendered and remove the following new proposed sections 95856 (g) and (h). (WSPA 1)

Comment: SDG&E and SoCalGas support the following in the Proposed Regulation: Changes to the requirements for the annual compliance obligation. (SEMPRA 2)

Response: Regarding the portion of the comments about the supposed removal of the retirement of compliance instruments for the annual compliance obligation, staff notes that the annual retirement requirement was reinserted in sections

95856(g) and (h) during the 15-day changes to address commenters concerns with the limited exemption and the potential for “lost” offsets. The 15-day changes clarify the compliance instrument retirement at annual and triennial surrender events, and removed the proposed language from section 95986(h). As such, use of the term “surrender” is appropriate throughout section 95856. Likewise, since compliance instruments will be retired annually, an order needs to be specified for the annual surrender event. This clarification to annual retirement will also prevent the holding limit and limited exemption from being adversely impacted, which were concerns raised by the regulated entities. As such, ARB staff believes the language as amended in the 15-Day Modifications will ensure annual and triennial retirement is clear and that these changes address concerns of market flexibility. Staff therefore declines to make the other changes proposed by the commenters.

Self-Selection of Order

G-2.2. Multiple comments: During the July 18 Workshop, stakeholders expressed a desire to have the ability to designate which allowances they would like withdrawn by CARB for retirement. Such a feature should be implemented, as it is necessary for covered entities that need to distinguish between their allowances by vintage, and would also facilitate tracking of allowances generally. The self-designation could be required by a certain date in advance of when the Executive Officer would withdraw the allowances under section 95856, and in the event that the covered entity failed to make such a designation, the provisions set forth in section 95856(h) would be controlling. The PAR or AAR would have the authority to make the designation. (NCPA 1)

Comment: Compliance instrument retirement order: Section 95856(h): New section 95856(h) specifies a mandatory compliance instrument retirement order under which the Executive Officer will withdraw compliance instruments from an entities’ Compliance Account. CPEM believes it is appropriate for the regulations to specify a compliance retirement order to be used as a default, if no other order is specified by a covered entity, and believes that the proposed order is appropriate for that purpose. However, CPEM strongly believes a compliance entity should have the flexibility to specify a different order to meet its own business needs. Specifically, CPEM requests that Section 95856(h)(1) be modified as follows:

> (1) When a covered entity or opt-in covered entity surrenders compliance instruments to meet its annual compliance obligation pursuant to section 95856(d), the Executive Officer will retire them from the Compliance Account in the order proposed by the entity, and if no such order is proposed**,** in the following order. (CPM 1)

Comment: For these reasons, WPTF opposes the proposed changes in Section 95856 regulation that would proscribe the order in which CARB would move compliance instruments from a covered entity’s Compliance account to the centralized Retirement Account for the triennial surrender obligation. We recommend instead that CARB build functionality into CITSS that would enable individual account holders to designate compliance instruments, by type and vintage, for retirement. In the event that an entity fails to indicate sufficient compliance instruments for movement to the Retirement account by the relevant surrender date, then CARB should manually pull instruments from compliance accounts in the order proposed. (WPTF 1)

Comment: The ARB should allow covered entities to select which compliance instruments they will use to meet their compliance obligations: At the ARB's July 18 Workshop, regulated entities expressed their opposition to the staff-proposed compliance instrument retirement order. To address these concerns, ARB Staff indicated that they would consider allowing covered entities to select which compliance instruments in their compliance accounts to retire prior to a compliance deadline. By allowing entities to self-select the compliance instruments they wish to retire, the ARB-proposed compliance instrument retirement order would only be enforced if a covered entity failed to select enough instruments for retirement to fulfill its compliance obligation. Retirement flexibility would allow compliance entities to better manage their portfolios, reduce the administrative burden for the regulatory agency, and reduce the risk of an unlawful taking of property if the ARB removed compliance instruments from an entity's account without counting those toward the entity's compliance obligation (e.g., if offset credits in excess of the 8% quantitative usage limit were taken during the annual compliance surrender). SCE supports this framework.

Unfortunately, ARB chose not to implement this change in the Proposed Regulation Order. The ARB instead sought to address the concern regarding the taking of offset credits in excess of the 8% limit by removing the provision for the annual retirement of surrendered compliance instruments under Section 95856(g).

SCE urges the ARB to adopt SCE's earlier suggestion of allowing compliance entities to self-select compliance instruments for retirement. The ARB should also continue exploring operational changes to the CITSS to allow for this elective transfer of compliance instruments for retirement. (SCE 1)

Comment: The new proposed section 95856(h)(2) imposes new requirements for the Executive Officer to retire compliance instruments in a certain order. This action continues to include additional restrictions and constraint on trading. The regulation should not require covered entities to retire allowances in a certain order. Instead, the market is best served if the covered entities are able to select which compliance instrument they wish to retire based on their economic decision.

Taking away this ability to choose reduces the incentive to behave economically and will reduce market efficiency. At the same time it does nothing to promote ARB's goals of market liquidity or decreasing the potential for market manipulation.

There may be business reasons why companies choose to retire instruments in a different order than that specified by the amendments. For example, companies may place different values on different instruments for reasons that are not clear at this time.

By specifying the order, ARB could be indirectly interfering in business optimization. Companies should have the option of specifying order of retirement. Where a company does not specify the order, ARB could follow the retirement protocol. While we understand that ARB wants to make sure that the surrender "happens", it should be the option of the company to determine the preferred order of instrument surrender.

CCEEB believes that the proposed rule should allow covered entities to specify the types and quantity of compliance instruments to retire and the order for retirement and that the new proposed requirements in 95856(h)(2) be removed. (CCEEB 1)

Comment: Issue 2: The new proposed Section 95856 (h) (2) imposes new requirements for the Executive Officer to retire compliance instruments in a certain order. This action continues to include additional restrictions and constraint on trading. The regulation should not require covered entities to retire allowances in certain order. Instead, the market is best served if the covered entities are able to select which compliance instrument they wish to retire based on their economic decision. Taking away this ability to choose reduces the incentive to behave economically and will reduce market efficiency. At the same time it does nothing to promote ARB's goals of market liquidity or decreasing the potential for market manipulation.

There may be business reasons why companies choose to retire instruments in a different order than that specified by the amendments. For example, companies may place different values on different instruments for reasons that are not clear or are competitively sensitive at a particular time. By specifying the order, ARB could be indirectly interfering in business optimization. The responsibility of initiating the surrender and specifying the order of surrender should remain with the obligated entity. Where a company fails to specify the retirement order, ARB could follow the retirement protocol. (WSPA 1)

Comment: However, under Section 95856(h)(2), the ARB will retire allowances under the triennial compliance obligation based on a mandated and pre- determined retirement order. TID is concerned that a mandated retirement order for the triennial compliance obligation will tend to result in higher compliance costs for regulated entities. Regulated entities are in the best position to determine how to meet their compliance obligation in the most cost effective manner.

At most, the ARB should allow regulated entities to choose a pre-determined retirement order. TID's proposed revisions to Section 95856(h)(2) in Attachment A would provide regulated entities with greater flexibility and would reduce compliance costs.

Revise Proposed Section 95856(h)(2) to provide greater flexibility for Regulated Entities in determining the order of retirement for their compliance instruments.

When a covered entity or opt in covered entity surrenders compliance instruments to meet its triennial compliance obligation pursuant to section 95856(f) <u>and the entity has</u>

not specified its desired retirement order by October 1st, the Executive Officer will retire them from the Compliance Account in the following order:

(A) Offset credits specified in section 95820(b) and sections 95821(b) through (d) with oldest credits retired first and subject to the quantitative usage limit set forth in section 95854:
(B) Allowances purchased from an Allowance Price Containment Reserve sale or compliance instruments pursuant to section 95821(f)(1);
(C) Allowances specified in section 95820(a) and 95821(a) with earlier vintage allowances retired first; and
(D) The current calendar year's vintage allowances and allowances allocated just before the triennial surrender deadline up to the true-up allowance amount as determined in section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1) if an entity was eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1).

Regulated entities should have the flexibility to determine their own retirement order for the triennial compliance obligation.

Regulated entities should have the flexibility to determine the order that their compliance instruments are to be retired: The September 4th Amendments would revise Section 95856 of the Cap-and-Trade regulation to provide that allowances would not actually be retired from the compliance account at the annual surrender obligation. TID Supports this change. (TID 1)

Comment: Section 95856(h): The Staff's proposed amendment establishes the "order" or "priority" in which a covered entity's compliance instruments will be retired. The Staff states that this provision is necessary "because it provides participants with details regarding the order in which compliance instruments will be considered by the Executive Director for compliance with the annual surrender event." Staff Report at p. 138. The proposed amendment to order (prioritize) the retirement of compliance instruments should be modified to provide that the Executive Director will only dictate the order in which a covered entity's compliance instruments are retired if the covered entity has not otherwise designated the order in which the instruments are to be retired. The Staff Report states, for example, that "allowances from California and linked jurisdictions will be the third type of compliance instrument to be considered in the Compliance Account .. . based on earliest vintage first." Staff Report at p. 139. For a variety of reasons (including but not limited to corporate taxation and financial accounting), however, the covered entity may prefer to retire "offsets," or compliance instruments with a more recent vintage ahead of instruments with an older vintage. One reason for this is that most companies recognize their free allocations at $0 on their balance sheet, but recognize purchased allowances at "cost." A company may wish to retire all of its freely allocated Vintage 2014 allowances before the company retires its purchased Vintage 2013 allowances, in order to optimize its balance sheet. The proposed Compliance Instrument Retirement Order would not permit this. The order in which a covered entity's compliance instruments are retired should be within the discretion of the covered entity (both for its annual compliance obligation and its triennial compliance obligation), with the possible exception of "true-up" allowances, as provided in Section 95856(h)(3). The Executive Director should only prescribe the order of retirement as the "default." (SHELL 1)

Comment: Moreover, the use and recognition of serial numbers in the existing CITSS software should allow for sufficient functionality to ensure that regulated entities do not violate any of the allowance usage restrictions, while at the same time, the use of serial numbers would preclude the need for a predetermined retirement order. (TID 1)

> **Response:** Staff understands the concerns raised by stakeholders. However, as stated in the Initial Statement of Reason, the overall policy objectives of the retirement order include maximizing the use of offsets up to the limit to ensure maximum compliance flexibility at least cost, and removing compliance instruments in the order of least to most challenging to liquidate at auction if the tracking system account were to be closed for a particular entity. The first compliance instruments to be retired are the compliance offset credits up to the 8% entity limit. These compliance instruments are the lowest cost compliance instruments and, because there is no holding limit on offsets, an entity has no requirement or incentive to place more offsets in their compliance account than they want retired. Second, the Executive Officer would retire allowances purchased from the Allowance Price Containment Reserve (Reserve) or Quebec issued early reduction allowances. These allowance types do not have a vintage and would be challenging to liquidate at auction, if the account were to be closed. Since entities would only buy from the Allowance Price Containment Reserve as a last resort, it is unlikely the Reserve allowances would be purchased and used for compliance. Third, the Executive Officer would retire allowances in the order of earliest to latest vintage. Since allowances can be banked but not borrowed this assures that eligible vintage allowances are retired for compliance first. Lastly, the Executive Officer would retire a limited amount of future vintage allowances. The only time future vintage allowances would be eligible for compliance is when they are provided by ARB for allocation true-up. Clarifying changes to the retirement order in 15-day changes to specify the exact order for retiring instruments at the annual and triennial surrender deadlines ensure the policy objectives stated in the Initial Statement of Reasons are met, while still providing market flexibility.
>
> Moreover, the design of CITSS does not currently support the ability of entity specification of compliance instrument retirement order. As such, the compliance instrument retirement order specified in the Regulation will remain. Staff therefore believes the amendments to specify the compliance order are necessary and declines to make the requested changes.

G-2.3. Multiple Comments: The next issue I'd like to comment on is with respect to flexibility in determining the retirement order for allowances. There's some provisions in the regulation or the 45-day rules that will provide additional flexibility with respect to the allowance transfer -- excuse me -- the annual retirement obligation that we believe there should be more flexibility with the triennial compliance obligation and specifically allow regulated entities to determine the order in which the retire their allowances. (TID 2)

Comment: ARB has created new language describing how it will select compliance instruments from covered entities' Compliance Accounts to be moved to the Retirement Account to meet compliance surrender obligations. If the proposal was designed to be a "default" protocol, to be used absent receiving timely instructions from the account holder, MSCG would strongly endorse the proposal. However, the proposal to remove the account holder's ability to designate which instruments it prefers to render to meet its retirement obligations is very peculiar. We do not see, nor has the Staff Report offered, any reason why ARB needs to remove this decision from the discretion of the compliance entity. Conversely, a compliance entity may find significant value in being able to select which instruments it wishes to surrender. The most obvious reason is to manage inventory costs. Different compliance instruments may be "on the books" at different costs, and the decision with regard to which instrument to surrender and which to keep in inventory can have a significant difference in reported accounting costs.

As a governing regulatory principle, we believe that maximum flexibility and control should always reside with the regulated entity, absent a compelling reason to do otherwise. No such compelling reason has been offered. For that reason, we strongly urge the Board to convert the proposal to a default protocol, but let the compliance entity retain the right to exercise discretion, and make its own choice as to which instruments are retired, if it so chooses. (MS)

Comment: CARB should provide covered entities the option to specify compliance instrument retirement order instead of eliminating the annual surrender obligation: The Regulation does not currently indicate in what order compliance instruments will be retired from covered entities' compliance accounts into CARB's Retirement Account. The Proposed Amendments would mandate such a retirement order and, in so doing, create the possibility that entities that placed too many offset credits into their compliance accounts prior to an annual compliance obligation becoming due would lose the value of those offsets and need to come up with additional compliance instruments to meet the triennial obligation.

Calpine believes that the underlying concern that stakeholders have expressed regarding over- surrendering offsets can be better resolved by providing functionality in CITSS for covered entities to specify which compliance instruments in their compliance accounts they would like to retire. CARB expressed a willingness to consider such an option at the July 18, 2013 stakeholder workshop. Rather than postpone the retirement of compliance instruments at each annual compliance obligation for up to two more years, CARB should simply allow covered entities to specify which instruments in their respective compliance account they are seeking to retire. The mandatory retirement order would then function as a backstop mechanism in the event that a covered entity does not specify the compliance instruments it would like to retire, in which case

Calpine would nevertheless urges CARB to return over-surrendered offsets to the entity's compliance account or credit them against future compliance obligations. (CALPINE 1)

Comment: Elimination of annual compliance surrender obligation. The Proposed Amendments would impose a mandatory retirement order for compliance instruments and, to avoid the circumstance where entities might be deemed to over-surrender offsets, would eliminate retirement of compliance instruments to fulfill the annual compliance obligation. By not retiring allowances at the annual compliance obligation, the Proposed Amendments would result in covered entities carrying large liabilities on their balance sheets, even after the 30% annual compliance obligation was deemed to be satisfied. This could cause confusion to the public, who may closely monitor companies' corporate filings to confirm that they have satisfied the compliance obligation. While Calpine appreciates CARB's efforts to avoid over-retirement of offset credits, the best way to avoid this is for CARB to allow entities to specify the retirement order for compliance instruments in their compliance account. (CALPINE 1)

> **Response:** ARB staff recognizes that some covered entities prefer to determine the retirement order of instruments in their compliance account. However, as stated in the Initial Statement of Reason, the overall policy objectives of the retirement order include maximizing the use of offsets up to the limit to ensure maximum compliance flexibility at least cost, and removing compliance instruments in the order of least to most challenging to liquidate at auction if the tracking system account were to be closed for a particular entity. The first compliance instruments to be retired are the compliance offset credits up to the 8% entity limit. These compliance instruments are the lowest cost compliance instruments and, because there is no holding limit on offsets, an entity has no requirement or incentive to place more offsets in their compliance account than they want retired. Second, the Executive Officer would retire allowances purchased from the Allowance Price Containment Reserve (Reserve) or Quebec issued early reduction allowances. These allowance types do not have a vintage and would be challenging to liquidate at auction, if the account were to be closed. Since entities would only buy from the Allowance Price Containment Reserve as a last resort, it is unlikely the Reserve allowances would be purchased and used for compliance. Third, the Executive Officer would retire allowances in the order of earliest to latest vintage. Since allowances can be banked but not borrowed this assures that eligible vintage allowances are retired for compliance first. Lastly, the Executive Officer would retire a limited amount of future vintage allowances. The only time future vintage allowances would be eligible for compliance is when they are provided by ARB for allocation true-up. To ensure these policy objectives are met, staff made clarifying changes to the retirement order in 15-day changes to specify the exact order for retiring instruments at the annual and triennial surrender deadlines. ARB believes that reinserting the annual retirement language in the 15-day changes also addresses the commenter's concerns about not retiring allowances at the annual compliance obligation resulting in covered entities carrying large liabilities on their balance

sheets, even after the 30% annual compliance obligation was deemed to be satisfied.

Additionally, compliance instruments do not have a serial number visible to covered entities; thus entities are technically limited on how they could order compliance instrument retirement. Under the scenario proposed by the commenters, if an entity did not wish to retire specific compliance instruments, that entity could simply keep the compliance instruments in the holding account. Finally, as stated in a previous response, the design of CITSS does not currently support the ability of entity specification of compliance instrument retirement order.

Accounting and Tax Implications of No Annual Surrender

G-2.4. Multiple Comments: To avoid this result, the Proposed Amendments would postpone retirement of compliance instruments to meet the annual compliance obligation, until the triennial obligation is due (i.e., for one or two more years). Rather than retiring compliance instruments, CARB would determine whether a covered entity has fulfilled its annual compliance obligation "by evaluating the number and types of compliance instruments in the Compliance Account." CARB staff states that this proposal is primarily in response to "stakeholder concern about not estimating the [quantity] of offsets correctly to be placed into the compliance account and potentially over supplying offsets relative to the 8 per cent usage limit during the annual surrender event when instruments are retired."

Calpine appreciates that CARB is attempting to resolve stakeholder concerns about how the mandatory retirement order risks over-surrender and forfeiture of valuable offset credits. However, the Proposed Amendments create the possibility for confusion between how companies must report liabilities for accounting purposes and public reports concerning compliance with the Regulation. Because CARB proposes to merely "evaluat[e] the number and types of compliance instruments in the Compliance Account" without transferring such compliance instruments into CARB's Retirement Account, compliance instruments relied upon to satisfy the annual compliance obligation will remain in each covered entity's compliance account, until the triennial compliance obligation is due (up to two years later). As a result, even though the annual compliance obligation will be deemed fulfilled by CARB, the entity may be required, under generally accepted accounting principles ("GAAP"), to continue treating the 30% annual compliance obligation as an outstanding liability. This can only lead to confusion among members of the public, who may look to corporate reports for confirmation that an entity has satisfied its annual compliance obligation, only to see that the company is still accounting for a large outstanding liability for emissions already subject to that obligation. (CALPINE 1)

Comment: However, we remain concerned about the staff proposal to establish a regulatory requirement for the order of retirement of compliance instruments for the triennial compliance obligation.

As we have noted previously, there may be financial accounting implications (and possibly corporate tax implications) for companies if CARB imposes a predefined retirement order. For example, most companies recognize their free allocations at $0 on their balance sheet, but purchased allowances at cost. In order to optimize its balance sheet, a company may wish to retire all of its freely allocated allowances of one vintage before it retires their purchased allowances of other vintages. Regulated entities are in the best position to determine the most cost effective means of compliance (a fundamental tenant of the cap-and-trade design) and should be provided with the flexibility to determine the most appropriate retirement order. (WPTF 1)

Comment: IETA's membership has a strong preference for individual entities to be given the flexibility to indicate which compliance units they would like to surrender. We appreciate the need to provide a default surrender order in case an entity fails to indicate its own surrender order, but this default order should not supersede an entity's preference, if indicated. We understand that the Compliance Instrument Tracking System Service (CITSS) currently does not have the functionality to allow entities to indicate their own retirement order preference, but our membership contends that the benefits of implementing such functionality outweigh the cost. Some tax and accounting considerations follow.

Tax and Accounting Considerations: ARB officials may wish to consider the EPA's Acid Rain Program in determining the importance of an entity's ability to choose which compliance units it retires in light of tax implications. In the Acid Rain Program, an entity has the option to choose to retire specific allowances based on their tax basis (this is often referred to as "specific identification" by the accountants).

For tax purposes the basis of a freely allocated allowance is zero. That contrasts with a purchased allowance, where for tax purposes the basis would be the purchase price. An entity can then choose to retire an allowance based on its tax basis. In the Acid Rain Program, since SO_2 allowances are treated as a capital asset, a company could choose allowances based on how it would impact its capital gains posture for a given year.

According to a Journal of Accountancy report, approximately three quarters of companies value freely allocated allowances at zero, and purchased allowances at cost1. With this in mind, entities may want to choose to retire compliance units in a different order than is proposed by ARB. Different entities will have different financial drivers depending on their industry, financial situation, accounting policy, etc. – so while one company may wish to retire freely allocated allowances first, another may wish to do the opposite. Similarly, one company may wish to retire earlier vintages first, and another may wish to retire later vintages first. Consider the following example:

> A company in California is expected to emit 100 tons of GHGs per year in 2013 and 2014, and ARB allocates 80 allowances/year for free (i.e. 80 vintage

2013 allowances and 80 vintage 2014 allowances) leaving a shortfall of 20 tons/year that must be bought in the marketplace.

Assume that this company is concerned about rising costs, so it buys 40 tons of vintage 2013 allowances (the most liquid contract) in the marketplace at $15/ton to hedge its price risk. The regulation allows the company to use vintage 2013 allowances for compliance with 2013 or 2014 emissions.

Assume, now, that for whatever reason (perhaps production was down), that company only actually emitted 90 tons in 2013 and 90 tons in 2014. This leaves it with 20 surplus allowances, which it banks for 2015.

The regulation says that ARB will retire allowances in a specific order, starting with the earliest vintages (i.e. all vintage 2013s will be retired first). So in the company's registry account, it is left with 20 vintage 2014 allowances. Since all of these were allocated for free, this would be valued at zero on the company's balance sheet.

However, depending on the company's inventory/accounting policy, that company may actually prefer to retire all freely allocated allowances first (including all vintage 2014s), leaving them with 20 vintage 2013 allowances instead (which they value at cost).

As this example points out, there are important accounting considerations that make it important that an entity has the option to choose its own compliance unit surrender order depending on different circumstances. IETA encourages ARB to provide this capability within CITSS. (IETA 1)

Response: ARB staff appreciates that the retirement order affects a covered entity's accounting. If an entity would prefer not to retire a compliance instrument, the account representatives may choose to keep it in the holding account, rather than submitting it for compliance. The goal of the retirement order is not to optimize an entity's tax exposure, but rather to minimize the compliance and administrative costs with the Cap-and-Trade Program. ARB staff will monitor compliance during the surrender events to ensure an effective implementation of the retirement order process.

G-3. POUs and Allowance Retirement

G-3.1. Comment: Section 95856(c) requires a covered entity to transfer compliance instruments from its holding account to its compliance account to meet its compliance obligation, and similar language is used in section 95856(f)(1). However, publicly-owned utilities ("POUs") that choose to have some or all of their allocated allowances deposited directly into their compliance accounts may not need to move instruments from their holding account into their compliance account in order to meet their compliance obligation – they may already have enough instruments in their compliance accounts. Therefore, these sections should be revised.

SCPPA's proposed changes to section 95856 are set out below:

§ 95856.

(c) A covered entity must ~~transfer from its holding account to~~ have in its compliance account a sufficient number of valid compliance instruments to meet the compliance obligation set forth in sections 95853 and 95855.

(f) Fulfillment~~Surrender~~ of Triennial Compliance Obligation.

(1) The covered entity must have~~transfer~~ sufficient valid compliance instruments in~~to~~ its compliance account to fulfill its triennial compliance obligation by November 1, 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect), of the calendar year following the final year of the compliance period. (SCPPA 1)

Response: If a POU has a sufficient number of valid compliance instruments to cover its compliance obligation already in its compliance account, it will not have to transfer any additional compliance instruments under section 95856(c). Moreover, section 95986(f)(1) sets the deadline for such transfers, and if the POU's compliance account already has a sufficient number of valid instruments before the deadline in section 95856(f)(1), it will have satisfied that provision. As such, staff does not believe the proposed changes are necessary and declines to make them.

G-3.2. Multiple Comments: Specify that the application of the set retirement order will not result in POUs breaching section 95892(d)(5): The compliance instrument retirement order in proposed new section 95856(h)(2) raises the prospect of inadvertent breaches of existing section 95892(d)(5). A new sentence should be added to section 95892(d)(5) to address this issue.

POUs are not permitted to use the allowances freely allocated to them by the ARB to cover compliance obligations arising from the generation of electricity that is sold into the CAISO markets (effectively, wholesale sales). Section 95892(d)(5) provides:

> Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets.

Proposed new section 95856(h)(2) sets out a mandatory retirement order for compliance instruments on the triennial compliance obligation deadline: offsets, Reserve allowances, normal allowances with earlier vintages retired first, and lastly true up allowances.

The application of this retirement order may result in a POU inadvertently breaching section 95892(d)(5). This could occur if the POU's retail sales for a year turn out to be lower and its wholesale sales for the year turn out to be higher than expected when the POU distributed its freely-allocated allowances for that year between its compliance account and its limited use holding account.

For example, assume a POU receives (for simplicity) 100 free allowances for 2014. It expects to have 90 tons of emissions from power used to serve its native load in 2014, so it directs 90 of the allowances into its compliance account. The POU expects to have 10 tons of emissions from wholesale power in 2014, for which it cannot use its free allowances, so it sends 10 allowances to its limited use holding account. However, by the end of 2014 it turns out that the POU's emissions from power used to serve its native load were only 80 tons, and its emissions from wholesale power were 20 tons. Assuming that the POU's allocation of free allowances for 2013 matched its native load emissions, and that its governing board has not approved the purchase of offsets, it has 10 too many free allowances in its compliance account for the first compliance period. Even if it purchases 20 allowances at auction to cover its wholesale power emissions, the POU has no way to ensure only 80 of the free allowances are retired. If all 90 are retired, the POU will have inadvertently used free allowances to meet part of its wholesale power emissions liability, breaching section 95892(d)(5).

Furthermore, even if a POU correctly projects its native load and wholesale sales, the fixed retirement order forces the POU to auction the allowances that are in excess of its expected native load to avoid breaching section 95892(d), even though the POU might have preferred to keep the extra allowances in its compliance account to cover its native load emissions obligation in a future year.

Presumably setting the retirement order was not intended to cause these issues. This should be clarified by inserting a sentence in section 95892(d)(5) stating that the retirement of freely-allocated allowances is not a breach as long as the utility has procured enough other compliance instruments to cover its wholesale power emissions liability. (SCPPA 1)

Comment: The Regulation should include a way to distinguish between freely allocated allowances and those purchased by an electrical distribution utility. Section 95856(h) of the Proposed Amendments makes no distinction between freely allocated and purchased allowances, which can be problematic for some electrical distribution utilities. In the event that entities are not allowed to designate their preferred allowance retirement order as discussed above, the Regulation should make such a distinction. Being able to distinguish between purchased and freely allocated allowances is necessary to address the restrictions on the use of allowances and allowance value set forth in section 95892(d)(5) of the Regulation. If the vintage alone is used to determine allowances withdrawn from the compliance account, an electrical distribution utility that has placed its freely allocated allowances directly into its compliance account could be in a situation where allowances are retired for a use prohibited by section 95892(d)(5). Therefore, the classification of allowances should be further defined to distinguish between freely allocated allowances and purchased allowances, and this designation should be taken into account before withdrawing allowances by vintage generally. (NCPA 1)

Comment: § 95856(h) compliance instrument retirement order: Under §95892(d)(5), electrical distribution utilities (EDUs) are prohibited from using the value of their allocated allowances to meet compliance obligations that do not benefit its retail ratepayers consistent with the goals of Assembly Bill 32, including the use of such allowances for electricity sold into the CAISO markets. GARB proposes to surrender compliance instruments from entity compliance accounts in the following manner: offsets (oldest vintage first), allowances purchased from the Allowance Price Containment Reserve (Reserve), allowances (oldest vintage first), then true-up allowances. Although an EDU would be in compliance with §95892(d)(5) with respect to its procurement of allowances, this surrender proposal could have the unintended effect of appearing to conflict with §95856(h).
Proposed § 95856(h) compliance instrument retirement order example of potential impact to publicly-owned utilities (POUs)

Background
CARB's current proposal does not allow entities to specify a retirement order of compliance instruments such as allowances and offsets. ARB is proposing to retire an entity's compliance instruments in its compliance account in the following order:

1. Offset credits
2. Allowances purchased from an Allowance Price Containment Reserve sale
3. Allowances per section 95820(a) and 95821(all earlier vintage allowances retired first
4. Current calendar year's vintage allowances and allowances allocated just before the triennial surrender deadline up to the true-up allowance amount (for industrial sector)

This proposed surrender order, if adopted, will conflict with Section 95892(d)(5} which applies to electrical distribution utilities (EDUs). EDUs are prohibited from using the value of their directly-allocated allowances to meet compliance obligations that do not benefit its retail ratepayers consistent with the goals of AB 32, including the use of such allowances for electricity sold into the CAISO markets. Emissions associated with these energy sales must be covered by compliance instruments purchased at auction or the secondary market. This provision especially impacts POUs who may have specified that most, or all, of its allocated allowances be put into its compliance account.

The following is an example that shows the conflict between the two provisions.
POU Entity 2013 allocation = 5 MMT

POU Specified Distribution of allocation = 5 MMT to compliance account (specified to ARB on Sept. 1, 2012)

POU 2014 allocation = 4.8 MMT

POU specified distribution of allocation = 4.5 MMT to compliance account (specified to ARB on Sept. 1, 2013); .3 MMT to auction

2013 Compliance Year Activity

POU emissions = 4.5 MMT (4.0 MMT allocated toward AB 32 goals, .5 MMT allocated to sales to CAISO). POU purchased .5 MMT to cover sales to CAISO.

2014 Compliance Year Activity

POU emissions= 4.5 MMT (4.0 MMT allocated toward AB 32 goals, .5 MMT allocated to sales to CAISO)

ARB implementation of the surrender order proposal:

For 2013 and 2014 "triennial" surrender:

Amounts needed for surrender:

2013: 4.5 MMT

2014:4.5 MMT

How POUs Should Surrender Allowances Per §95892(d)(5)			(Allowance Values in MMT)	
	2013		2014	
	Directly-Allocated Allowances	Purchased Allowances	Directly-Allocated Allowances	Purchased Allowances
Direct Allocation	5.0		5.0	
Allowance Purchases		0.5		0.5
Surrender for Native Load Emissions	4.0	0.0	4.0	0.0
Surrender for Wholesale Emissions	0.0	-0.5	0.0	-0.5
Allowances Remaining	1.0	0.0	1.0	0;0

How POUs Should Surrender Allowances Per §95892(d)(5)		(Allowance Values in MMT)		
	2013		2014	
	Directly-Allocated Allowances	Purchased Allowances	Directly-Allocated Allowances	Purchased Allowances
Direct Allocation	5.0		5.0	
Allowance Purchases		0.5		0.5
Surrender for Total Emissions (Native Load + Wholesale)	-4.5	0.0	-4.5	0.0
Allowances Remaining	0.5	0.5	0.5	0.5

Although ARB and the POU compliance balances are the same in this instance, ARB surrenders the allocated allowances to cover the emissions associated with the CAISO sales. LADWP desires confirmation that ARB recognizes this difference in accounting of allowances and will not penalize the POU before it finalizes its compliance instrument surrender proposal. (LADWP 1)

Comment: The regulation should distinguish between purchased and freely allocated allowances: Section 95856(h) of the Proposed Amendments specifies the order in which allowances are retired from a covered entity's compliance account. Under the proposal, the Executive Director will evaluate the number and type of compliance instruments in that account, and will retire compliance instruments in the following order: offset credits, allowances purchased from the allowance price containment reserve, allowances generally with the earliest vintages first, and finally, true-up allowances. This proposal does not distinguish between allowances that are freely allocated to electrical distribution utilities and those that are purchased (either through the auction or other sales). Because of the restriction placed on the use of allowance value from freely allocated allowances in section 95892(d)(5), allowances retired based strictly on the vintage could result in the retirement of allowances for prohibited transactions. In order to address this concern, the classification of allowances should be further defined to distinguish between freely allocated allowances and purchased allowances, and regulated entities should be allowed to specify the amount to be retired from each of these classifications, with earlier vintage allowances retired first within each classification. This change would ensure that electrical distribution utility is able to comply with the restrictions on the use of allocated allowances, such as the prohibition on the use of allowances/allowance value to meet compliance obligations for electricity sold into the CAISO markets. (MSR 1)

Comment: Recommendation: SCPPA's proposed changes to section 95892(d)(5) are set out below:

> (5) Use of the value of any allowance allocated to an electrical distribution utility, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets (“Non-Retail Compliance Obligation”). Retirement of allocated allowances in accordance with section 95856(h)(2) will not constitute a breach of this section provided that the electrical distribution utility has a quantity of alternative valid compliance instruments in its compliance account at least equal to its Non-Retail Compliance Obligation. (SCPPA 1)

Comment: In addition, covered entities such as EDUs would not have serial number information to decipher which allowances in their compliance accounts are allocated versus purchased for sales into the CAISO. Thus, although the EDU's and CARB's compliance account balance would be the same in terms of the number of allowances, the EDUs' accounting of allowances by vintage and date procured may not match CARB's. As long as CARB recognizes this situation and determines that EDUs will not be penalized for differences in accounting for allowances because of the manner in which they were surrendered, LADWP can support CARB's surrender proposal. (LADWP 1)

Comment: On the allowance surrender designation, we ask that the entities be allowed to designate which allowances are surrendered for retirement. And specifically, that there be a distinguishment between the allowances that are freely allocated to electrical distribution utilities and those that are purchased.

The reason for this is because there are restrictions in the regulation on the use of freely allocated allowances. And without an ability to ensure that the allowances that are drawn out of an account simply by vintage could result in a POU that has placed their freely-allocated allowances into their compliance account being found in violation, if those allowances aren't clarified to show that the ones that were withdrawn are the ones that were purchased and not freely allocated. (NCPA 2)

> **Response:** In response to stakeholder comments, staff added section 95856(h)(4) to the regulation as part of the 15-day changes to ensure electric distribution utilities will not be in violation of the regulation if sufficient compliance instruments are in the entity’s compliance account. Staff believes this new provision effectively addresses the concerns raised by the public utilities.

G-4. Annual Obligation Surrender

G-4.1. Comment: These proposals recognize the important role offsets can play to reduce unnecessary upward pressure on allowance prices and prevent depletion of the allowance price containment reserve while meeting the environmental goals of the program.

ARB should further study the removal of holding limits and of other means of increasing the supply of compliance instruments, such as offset carryover across compliance periods, the redistribution of unused offsets, and widening the offset market geographically and temporally. (WSPA 1)

> **Response:** Staff appreciates the comment, but notes that the commenter is not recommending any regulatory change. Staff will monitor the Cap-and-Trade Program, including holding limits, and will propose any future modifications, as necessary. With regard to offsets, staff will continue to study the need and potential for more offset protocols and mechanisms.

G-5. ARB's Authority to Retire Compliance Instruments

G-5.1. Multiple Comments: Furthermore, the amendments would grant ARB inappropriate authority at the triennial surrender to enter a company's CITSS account and "take" compliance instruments (e.g. allowances) to meet the triennial surrender obligation. While this surrender is required for compliance, it is more appropriate for companies to have the option to execute this surrender voluntarily. Only if the surrender is not done by a specified date, should ARB have the capability and authority to initiate the surrender. (CCEEB 1)

Comment: Furthermore, the amendments would grant ARB inappropriate authority at the triennial surrender to enter a company's CITSS account and "take" compliance instruments (e.g. allowances) to meet the triennial surrender obligation. While this surrender is required for compliance, it is more appropriate for companies to have the responsibility to execute this surrender. Only if the surrender is not done by a specified date, should ARB have the capability and authority to initiate the surrender.

Recommendation: The proposed rule should allow covered entities to specify the types and quantity of compliance instruments to retire and the order for retirement. We recommend the new proposed Section 95856 (h) (2) (shown below in ~~strike-through~~) be removed.

> ~~§95856(h)(2). Surrender of Compliance Instruments~~
>
> ~~When a covered entity or opt-in covered entity surrenders compliance instruments to meet its triennial compliance obligation pursuant to section 95856(f), the Executive Officer will retire them from the Compliance Account in the following order:~~
>
> ~~(A) Offset credits specified in section 95820(b) and sections 95821(b) through (d) with oldest credits retired first and subject to the quantitative usage limit set forth in section 95854;~~

~~(B) Allowances purchased from an Allowance Price Containment Reserve sale or compliance~~ ~~instruments pursuant to section 95821(f)(1);~~

~~(C) Allowances specified in section 95820(a) and 95821(a) with earlier vintage allowances retired~~ ~~first; and~~

~~(D) The current calendar year's vintage allowances and allowances allocated just before the triennial surrender deadline up to the true-up allowance amount as determined in section 95891(b),95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1)~~ ~~if an entity was eligible to receive true up allowances pursuant to section 95891(b), 95891(c)(3)(B), 95891(d)(1)(B), 95891(d)(2)(B), 95891(d)(2)(C), 95891(e)(1), or 95894(d)(1)."~~ (WSPA 1)

Response: ARB staff disagrees with these comments. Entities are responsible for surrendering compliance instruments. For example, when entities place compliance instruments into compliance accounts, those compliance instruments are effectively surrendered. Requiring the covered entity actively move instruments into its compliance account preserves the covered entity's choice on which instruments ARB should consider for retirement. Pursuant to section 95856(h)(2), the Executive Officer of ARB only retires the surrendered compliance instruments after the annual/triennial surrender deadline, which is the regulatory (not voluntary) deadline. ARB staff therefore declines to make the requested deletions.

H. IMPLEMENTATION OF AUCTION AND TRADING REQUIREMENTS

H-1. Auction

Auction Application

H-1.1. Comment: Auction Participation Information: Issue: the current prohibition on auction information disclosure prohibit certain transactions that would help small and medium size covered entities procure allowances.

Proposed Change: modify Section 95914(c)(1) to permit limited exchange of information in certain transactions that are disclosed to ARB. (CHEVRON 2)

> **Response:** Based on transaction contracts reviewed thus far, staff does not see the value in permitting auction participation information exchange as suggested by the commenter. As such, staff declines to make the suggested change. Staff notes that release of limited information is allowed as specified in section 95914(c)(2).

H-1.2. Multiple Comments: Revise section 95912(e) regarding maintenance and modification of auction approval: Section 95912(e)(1) states that once an entity is approved for an auction, it does not need to submit an application for future auctions unless:

> there is a material change to the information contained in the approved application, there is a material change in the entity's Cap-and-Trade Program registration pursuant to section 95830 …

If a change in the status of an investigation (section 95912(d)(4)(E)), or the arrival or departure of an employee with information on compliance instrument transactions or holdings (section 95830(c)(1)(I)), constitute a "material change", large entities would have to complete full auction applications for virtually every auction. The information that should be excluded from section 95912(d)(5), as discussed above, should also be excluded from section 95912(e)(1).

SCPPA's proposed changes to section 95912(e)(1) are set out below:

> (1) Once the Executive Officer has approved an entity's auction participant application, the entity need not complete another application for subsequent auctions unless there is a material change to the information contained in the approved application <u>(other than information pursuant to subsection 95912(d)(4)(E))</u>, there is a material change in the entity's Cap-and-Trade Program registration pursuant to section 95830 <u>(other than subsections 95830(c)(B), (I) and (J))</u> ...

Section 95912(e)(2) provides that:

> An entity approved for auction participation must inform the Auction Administrator at least 30 days prior to an auction when reporting a change to the information disclosed, otherwise the entity may not participate in that auction. …

The purpose of this section is unclear. From section 95912(e)(1), it appears that if an entity has a material change to the relevant information since it was previously approved for an auction, it must complete another full auction participant application pursuant to section 95912(d)(4). Is the report to the Auction Administrator under section 95912(e)(2) intended to be in addition to, or in substitution for, a full auction participant application?

If a full auction participant application is required, an additional report (with the same deadline) under section 95912(e)(2) seems unnecessary, and this section should be revised to direct the applicant to comply with section 95912(d)(4) again.

If this report is in substitution for a full auction participant application, section 95912(e)(1) should be amended to make this clear. In addition, section 95912(e)(2) should be amended to clarify that a "change to the information disclosed" does not include changes to information disclosed under sections 95830(c)(B), (I) and (J), or section 95912(d)(4)(E). (SCPPA 1)

Comment: The second item is the application for participating in the auction. And this proposal is really broadly written and such that any changes in an entity's auction or account application will result in denial of the entity's ability to participate in the auction. We believe this requirement is too restrictive and recommends that CARB work to define what constitutes a change that would lead to denial of an entity to participate in an auction.

It would be extremely difficult for an entity to have no changes at all in an entity's directors and officers within the time period stated, especially if the entity plans to participate in all four quarterly auctions. (LADWP 2)

> **Response:** ARB staff notes that no changes were made to section 95912(e)(1) as part of this rulemaking action. As such, the comments are outside the scope of this rulemaking. However, staff believes section 95912(e)(1) clearly indicates that material information is that information specified in section 95912(d)(4), and any change to such information must result in a newly submitted application. With respect to section 95912(e)(2), this section corresponds to the same timeframe as in section 95912(e)(1).
>
> Subsection 95912(e) has two parts. The first part explains that in the event of a material change, an entity should resubmit an auction application. The second part explains that such a change should be disclosed at least 30 days before the auction if an entity intends to participate. Finally, ARB staff disagrees that completing an auction application is overly burdensome. There are 5 to 6

screens of information to fill out, much of which is auto-populated. As such, ARB staff declines to make the suggested changes.

H-1.3. Comment: We do remain concerned about some of the market monitoring provisions. We have submitted written comments discussing our concerns in detail, but I would just say there is a section that appears to preclude SoCal Gas and SDG&E from auction participation due to circumstances outside of their control. And I note in the Resolution that staff is going to continue to work with compliance entities to resolve some of these issues, and we appreciate that effort. (SCGE)

Response: ARB staff is aware of the special relationship between SoCal Gas and SDG&E. So far this relationship has not triggered any complications, nor does staff expect it will. ARB staff looks forward to continuing to work with these stakeholders to ensure an efficient operation of the program.

H-1.4. Comment: Particularly, I want to encourage staff to continue to clarify the information, submission, and attestation requirements to enable auction participation and program compliance. And this includes the treatment of confidential information and the release or provision of information to other regulatory agencies such as the Public Utilities Commission. (SCE 3)

Response: In response to stakeholder comments, ARB staff modified section 95914(c)(2)(E) of the proposed amendments as part of the 15-day changes to make explicit that Electric Distribution Utilities may disclose information required by the California Public Utilities Commission.

With respect to the treatment of confidential information, ARB staff notes that section 95921(e) specifies that ARB protects confidential information to the extent permitted by law, which would include the requirements of the California Public Records Act (Government Code section 6250 et seq.) and the procedures set forth in title 17, California Code of Regulations, section 91000 to 91022. Under section 95921(e), any release by the accounts administrator of transfer prices and quantities of compliance instruments would only be done in a manner which protects the identity of the parties to the transfer as well as the number of compliance instruments in holding accounts. Moreover, under section 95914(c), ARB has specifically prohibited participants in the Cap-and-Trade Program (including their consultants and advisors) from sharing information pertaining to bidding and auction participation, except in a number of limited situations. This information would include an entity's intent to participate (or not) in an auction, bidding strategy, bid price or bid quantity information, and information on bid guarantees. All of this information would be considered market sensitive, confidential business information by ARB and would be treated as such in the event of a request for disclosure under the California Public Records Act.

ARB staff notes that except under the limited circumstances provided in section 95914(c)(2), the prohibition on information sharing contained in section 95914(c), and the express provisions for protecting confidential information contained in section 95921(e), require (and allow) a government entity who happens to be a covered entity in the Cap-and-Trade Program to protect this confidential information from disclosure in the event of a request under the California Public Records Act.

H-1.5. Comment: Auction intent to bid notification: Section 95912(f); Section 95913(e). New Section 95912(f) specifies that an entity that "intends to participate" in an auction must inform the Auction Administrator at least 30 days prior to an auction of its intent to bid in an auction. Similarly, new Section 95913(e) provides that an entity must inform the reserve sale administrator at least 20 days prior to a reserve sale of its "intent to bid." CPEM requests that the ARB clarify that this indication of intent does not represent a binding commitment to participate in such auctions. For example, an entity may, more than 30 days prior to an auction, intend to participate, but prior to such auction find an over-the-counter transaction under which it can purchase the compliance instruments required at a fixed price, thereby avoiding auction risk, and rendering its auction participation unnecessary. CPEM recommends that Section 95912(f) be revised, as set forth below, with a corresponding change to Section 95913(e):

Auction Intent to Bid Notification Requirements. An entity that intends to participate in an auction must inform the Auction Administrator at least 30 days prior to an auction of its intent to bid in an auction, otherwise the entity may not participate in that auction. <u>Informing the Auction Administrator of an intent to bid does not commit the entity to participate in the auction.</u> (CPM 1)

Response: Staff does not agree that the definition of "intent" needs to be in the Regulation. "Intent to bid" allows ARB to prepare the auction for expected bidders. Entities are free to decide not to turn in a bid guarantee or not to bid. As such, the proposed language is not necessary and staff declines to make the change.

H-1.6. Comment: Entities Should Have an Opportunity to Correct Errors or Omissions Prior to Auction Cancellation: Likewise, PG&E suggests changes to Section 95914(a), concerning the ability of ARB to cancel or restrict auction participation based on certain determinations. PG&E requests that an entity that provided inaccurate information or omitted required information be given an opportunity to correct such error or omission before the Executive Officer cancels or restricts that entity's participation in the auction. ARB provides similar flexibility to entities to correct errors concerning transfer requests, and offset validation processes. While PG&E understands ARB's need for accurate and complete information, the impact on PG&E and its ratepayers for what may be an administrative error is not justified. Accordingly, it is reasonable and consistent with ARB regulations to provide similar flexibility to the auction process.

Section 95914(a): The Executive Officer may cancel or restrict a previously approved auction participation application or reject a new application if the Executive Officer determines, <u>in each case after the individual has been notified</u>

of the failure and given an opportunity to correct the error or omission, as needed, that an entity has... (PGE 2)

Response: Staff disagrees that an opportunity to correct errors in auction application or account applications should be codified in the Regulation. That said, the Regulation does not force the Executive Officer to cancel auction applications in the case of missing material information. The Regulation instead says that the Executive Officer may cancel the auction applications. Section 95914(a)(1) and (2) allow cancellation or restriction of auction participation for the provision of false or misleading facts or withholding material information from an entity's auction application or its CITSS account application. Neither of these provisions pertains to inaccurate information or omitted required information. ARB staff reviews all CITSS applications for accuracy and completeness and after consultation with the entity account representatives, corrects CITSS account applications as needed. The auction platform relies primarily on CITSS for required information needed to complete an auction application. ARB staff believes that our administrative procedures address the concerns expressed by PG&E in this comment and that no change in the text is needed.

Auction Application Attestation

H-1.7. Multiple comments: The ARB should not make acceptance of an entity's auction application contingent on an attestation that the entity has not been subject to investigation: The auction participant application, which must be completed by all entities wishing to participate in the ARB's quarterly auctions, currently requires the applicant to identify any "previous or pending investigation" for market violations under current regulations. In Section 95912(d)(4)(E) of the Proposed Regulation Order, this prerequisite for completing the auction application has been changed to require the applicant to attest that the participating entity, along with any other entities with which it shares a direct or indirect corporate association, has not been subject to any previous or ongoing investigation. Below, SCE identifies three critical problems with the attestation provision as proposed by the ARB.

A. Investigations do not constitute evidence of market manipulation or wrongdoing: Like many other large compliance entities in the cap-and-trade program, SCE actively participates in a variety of different markets, including markets for power, natural gas, securities, derivatives, and emissions. It is common practice for regulators in many of these markets to investigate the actions of many market participants in response to any abnormal functioning of the market. Moreover, such regulators do not always inform the market participants that they are being investigated. Such investigations frequently conclude with many, if not all, of the investigated entities cleared of any charges.

Simply knowing about any previous or ongoing investigations opened against a compliance entity without knowing the outcomes of these investigations would not serve any legitimate purpose for the ARB or Auction Administrator. Information on convictions and penalties assessed as a result of market violations would prove much more relevant to the ARB as a tool to prevent market manipulation.

B. A participating entity may not be privy to information regarding market investigations of other entities with which it shares a corporate association: Many compliance entities that participate in the ARB auctions, including investor-owned utilities such as SCE, operate as wholly-owned subsidiaries of parent companies, which may also own other commercial entities in whole or in part. These other subsidiary companies would fall under the definition of direct or indirect corporate associations as set forth in the cap-and-trade regulation, and thus would be included in the requirement for the compliance entity to attest to the absence of any market investigations in its auction application.

However, due to rules governing affiliate conduct and standard company practices for information disclosure regarding ongoing legal investigations, company representatives completing the auction application on behalf of the compliance entity may not have access to information regarding previous or ongoing investigations for market violations at other companies with which the compliance entity shares a direct or indirect corporate association. It is not reasonable for the ARB to require that compliance entities make attestations based on potentially sensitive legal information from other corporate entities.

C. It is unreasonable for the ARB to deny an entity's auction application solely based on the disclosure of previous or ongoing market investigations: Participation in the ARB auctions is an important mechanism for ensuring compliance with the cap-and-trade regulation, especially for entities with large compliance obligations that are subject to regulatory restrictions regarding their participation in secondary exchange-traded or over-the-counter markets for compliance instruments. Allowance awards from the ARB auctions also constitute a major source of liquidity that flows into secondary markets for compliance instruments as compliance entities hedge or refine their positions. If the ARB excludes entities that disclose a previous or ongoing investigation from participating in the auctions, as is currently proposed, the ARB would severely limit the possible avenues for the excluded entities to satisfy their compliance obligations and substantially reduce available liquidity in the secondary markets. Both of these outcomes would result in increased costs for all compliance entities to meet their compliance obligations under the cap-and-trade regulation, producing costly and undesirable results for compliance entities and the program as a whole.

There is no reason why the presence of an investigation alone, without a conviction or penalty, should affect the investigated entity's ability to participate in the auctions, especially given the strong existing controls that the ARB employs around auction conduct and market monitoring. This unnecessary control measure could exclude major players from participating in the auctions. Rather than resulting in fairer auctions or reducing the risk of manipulation, this measure would instead raise compliance costs for all entities and cripple the functioning of the entire market.

Since investigations do not equate to evidence of market manipulation or other wrongdoing, the exclusion of compliance entities from bidding at auction based solely upon a prior investigation having taken place would not achieve the ARB's goal of reducing market manipulation. Accordingly, the ARB should change its proposed requirement for applicants to submit the aforementioned attestation as part of their auction applications. The ARB should require applicants only to disclose penalties or punitive actions that they have incurred for violations of market regulations, but not require information regarding ongoing investigations or actions taken against other associated entities. Unless the ARB deems the information materially relevant to bidding behavior in the auctions, the disclosure of this information should not prevent compliance entities from participating in the ARB auctions. (SCE 1)

Comment: Section 95912(d): Auction administration and participation application: Section 95912(d)(4)(e) is problematic as written because it appears to deny auction participation to entities with a "corporate association, direct corporate association, or indirect corporate association pursuant to section 95833" that has been subject to "any previous or ongoing investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation." This does not seem to be ARB's intent and is not reflected in the Initial Statement of Reasons (ISOR) for the regulatory change. Section 95912(d)(4)(e) should be modified to be consistent with the ISOR so that information on current investigations is reported on the auction participation application.

Modification to Section 95912(d)(4)(e) (Auction administration and participation application)

> An attestation that the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, is ~~has~~ not ~~been~~ subject to any ~~previous or~~ ongoing investigation, whether previously identified or not, with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of any ongoing investigation; or, if there is an ongoing investigation, provides required information on the investigation; (SEMPRA 2)

Comment: WPTF is also concerned with the new language in Section 95912(4)(E) that would greatly expand existing requirement for an entity registering for an auction disclose any previous or pending investigations regarding the entity's violation of commodity, security or financial market rules. The new language would instead require an attestation that has not only the entity not been subject to investigation, but in addition, no entity with which it has a corporate association has been subject to investigation.

WPTF considers this revision to be completely inappropriate for two reasons. First, we object to the requirement of disclosure of investigations of entities with which the registering entity has a corporate association. Registering entities are not likely to have knowledge of the investigations of any corporate associates, particularly with staff's proposed expansion of the scope of corporate association. Second, the language is problematic because it would essentially prevent any entity that has been subject to investigation at any point in time from participating in auctions.

WPTF therefore opposes the proposed changes to Section 95912(4)(E). (WPTF 1)

Comment: Auction Administration and Participation Application – Section 95912: New language in Section 95912(4)(E) adds a requirement that entities who desire to participate in an auction provide an attestation that the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, has not been subject to any previous or ongoing investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities or financial market, including a change in the status of an ongoing investigation. When considered in light of the previously addressed issues on what may be thousands of corporate associations for large corporations such as BP, this requirement is wholly unworkable and would preclude many, if not most, large regulated entities from participating in auctions.

Virtually all large entities that have participated in commodities, securities or financial markets with millions of transactions across the globe are likely to have been subject to investigation for alleged violations. The current language contains no threshold or time limit on investigations. When combined with the regulation's requirement that the attestation also applies to what may be thousands of corporate associations, there will be virtually no way to track or report investigations that may have occurred at any time in the past with associations that may take place with entities all over the world – let alone allow attestation that no investigation has occurred - ever.

It is our understanding that it is not staff's intention that an inability to provide the attestation would result in a prohibition from participation in an auction. However, the regulation clearly does not reflect this intention.

BP strongly suggests that 1) this section of the regulation apply only to ongoing investigations involving the entity participating in the auction, and not to a broad range of unrelated corporate associations, (i.e. removing the language in 95912(d)(4)(E) which reads and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833) and 2) the regulation requires simply that the entity planning to participate in the auction disclose all ongoing investigations, and not provide an attestation that no investigation has ever occurred. (BP 1)

Comment: Auction Administration and Participant Application (S95912(d)(4), page 173): ARB proposed the following language: "An attestation that the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, has not been subject to any previous or ongoing investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation…" The requirement, covering "the entity" and "all other entities" with which it is directly or indirectly associated is so broad as to be impossible to comply with because an entity cannot be expected to know if any such association "has been subject to previous or ongoing investigations". Moreover, even if investigations were undertaken in the past, or are even pending, an investigation does not imply wrong-doing.

Of even greater concern, one of the currently required attestations requires the company to confirm that it is not under investigation for potential violation of any rule, regulation or law associated with any commodity, securities, or financial market. A company might not know that it is under investigation. Furthermore, the proposed amendments would expand this to also require that the company attest that none of its corporate associations is similarly under investigation. This is clearly regulatory over-reach, unreasonable, and will place a burden on companies that is impossible to satisfy. It could, in fact, result in chilling the market – which is exactly the opposite of ARB's intent.

Recommendation: ARB should withdraw the proposed amendments that expand attestation requirements. Any agency could initiate an investigation, or any individual could request an investigation or initiate a lawsuit leading to an investigation, and the entity would be unable to participate in an auction and to remain compliant with the Cap & Trade Regulations. If any attestation is required, it should only be pertaining to actual findings of violations of laws pertaining to the Cap & Trade regulation by the attesting party and not its associates. (WSPA 1)

Comment: When registering for the auction, entities must now attest that they have not been subject to any previous or pending investigation related to securities, commodities or financial markets. This proposal is unworkable because it would exclude entities from participating in an auction merely for having been investigated, even if no wrongdoing is ever uncovered. Chevron believes the current requirement – disclosure of such investigations – is sufficient to ensure appropriate market monitoring. (CHEVRON 2)

Comment: Section 95912(d)(4)(E): The Staff's proposed amendment to the items that must be included in the "application" for auction participation would require an attestation that the entity participating in the auction, "and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association" (pursuant to Section 95833) has not been subject to "any previous or ongoing investigation with respect to any alleged violation of any rule, regulation or law associated with any commodity, securities, or financial market . .. ." The Staff states that this new provision is needed "to improve ARB's ability to monitor investigation of alleged violations in other financial markets . . . ." Staff Report at p.176.

This proposed amendment is overreaching and unreasonable. Under Section 95833(a)(4), an "indirect" corporate association can be established with an ownership interest that is no more than 20 percent. It is unreasonably burdensome to require the applicant to undertake the research to ascertain whether an entity with an "indirect corporate association" is the subject of an allegation of wrongdoing under financial market rules. If such a disclosure requirement is to be imposed, the requirement should be limited to entities with which the applicant has a "direct corporate association." This proposed amendment should be modified or stricken. (SHELL 1)

Comment: Clarify that a previous or ongoing investigation, if disclosed, will not prevent auction participation: The proposed revisions to section 95912(d)(4)(E) of the Regulation require an entity to attest, as part of its application to participate in an auction, that it:

> has not been subject to any previous or ongoing investigation with respect to any alleged violation of any rule, regulation or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation.

It follows that if an entity has been subject to any previous investigations, it would not be able to make this attestation and therefore could not apply to bid at any auction. This would exclude a large number of covered entities from the auctions. For example, many electric sector entities were investigated as a result of the California electricity market crisis.

At a meeting with utilities on October 3, 2013, ARB staff members stated that this section was not intended to have such a draconian effect, and that entities that were subject to relevant investigations merely need to list them (as provided in the July 2013 discussion draft of the Regulation), and can then participate in the auctions. This position is reasonable. The drafting of section 95912(d)(4)(E) needs to be revised to reflect the staff's intent, as the currently- proposed wording of this section does not allow entities to provide a list of investigations.

ARB staff members also stated that they do not require entities to list all investigations they have been subject to over their history (which would include investigations that were concluded decades ago), but only investigations that (a) are ongoing at the time of the auction application; or (b) were ongoing at the time of a previous auction application and thus were listed on a previous auction application. These limits are welcome and should be reflected in the Regulation.

Finally, section 95912(d)(4)(E) should be revised to remove the impossible requirement for an attestation that the entity "has not been subject to … a change in the status of an ongoing investigation." All investigations will have changes in their status at some stage.

It should suffice for an entity to list its ongoing investigations and note any change in status since the previous auction application.

> **Recommendation:** SCPPA's proposed changes to section 95912(d)(4)(E) are set out below:
>
> (4) … The entity must provide information and documentation including:
>
> > (E) An attestation that the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, has not been subject to any previous or ongoing investigation with respect to any alleged violation of any rule, regulation or law associated with any commodity, securities, or financial market~~, including a change in the status of an ongoing investigation~~. If the entity participating in the auction is not able to make this attestation, it must provide a list of such investigations that are ongoing at the time of the auction application or were ongoing at the time of a previous application under this section, noting any change in the status of the investigation since the previous application. (SCPPA 1)

Comment: Section 95912. Investigation disclosure language should be modified: Finally, PG&E proposes the following modifications to the ongoing investigation disclosure requirement for auction participation. For a company as large as PG&E, knowledge and materiality qualifiers are essential to PG&E's ability to provide the requested representation. PG&E would not want to violate the Cap-and-Trade regulations due to its failure to report a minor administrative violation of a CFTC rule connected to its energy purchases, which would likely be unrelated to PG&E's Cap-and-Trade compliance. In addition, the required attestation should pertain only to those investigations that are currently pending before applicable entities.

> (E)~~(C)~~. An attestation that to the best of the participating entity's knowledge, the entity participating in the auction~~, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, has not been~~ is not aware ~~subject to The identification~~ of any ~~previous or~~ ongoing ~~pending~~ investigation by the U.S. Securities and Exchange Commission or the Commodity Futures Trading Commission, with respect to any alleged material violation of any ~~rule, regulation, or~~ law ~~associated with any~~ applicable to commodities trading~~y, securities, or financial market, including a change in the status of an ongoing investigation;~~ and (PGE 2)

Comment: §95912(d)(4)(E) auction attestation: CARB proposes to establish a new condition for participating in an auction. Specifically, the proposed amendment would require an entity to attest that the entity "has not been subject to any previous or ongoing investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation."

This amendment would change the provision from a disclosure requirement to an attestation requirement. The existing regulations only require an entity to identify previous or ongoing investigations. This is a significant change in the rules for participating in an auction and this new requirement could unnecessarily bar many entities from participating in the auction. The fact that there was an investigation would be sufficient to disqualify an entity even if that investigation determined the alleged violations totally lacked merit.

LADWP prefers that CARB eliminate the proposed attestation requirement or limit the scope of the attestation. One way to narrow the scope is to limit the attestations to previous investigations in which a violation was determined. CARB would continue to have broad authority to limit or deny entities from participation in an auction. For example, CARB can deny registration for the cap-and-trade program (which is a condition for participating in the auction) "based on the information provided" to CARB under §95830(c)(8). (LADWP 1)

Comment: Section 95912(d)(4)(E) adds a provision requiring that an entity participating in an auction (including all associated entities) submit an attestation indicating that it has never been subject to any previous or ongoing investigation regarding “any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation”.

This is a significant divergence from the previous regulation language, which required just an “identification” of whether an entity had been involved in any investigation regarding the above- mentioned transgressions.

Is an entity unable to attest to such a statement denied from participating in an auction? If so, the language of the attestation seems unnecessarily harsh, not even taking into consideration whether guilt is proven during an ongoing investigation.

Further, the idea an entity should be denied participation in an auction due to the fact that even one employee within an organization with thousands of employees all over the world could have been found guilty of a violation at one point or another seems extreme.

IETA recommends that ARB revert to the original language from the current regulation as opposed to this proposed amendment. (IETA 1)

Comment: Section 95912. Investigation disclosure language should be modified: None of the Joint Utilities would want to violate the Cap-and-Trade Regulation due to a failure to report a minor administrative violation of a CFTC rule connected to its energy purchases, which would likely be unrelated to their Cap-and-Trade compliance. The

Joint Utilities recommend ARB match the auction platform provisions more closely by revising Section 95912(d)(4)(E) to allow an entity to list any previous or ongoing investigations if it is not able to attest that there are no such investigations. ARB should also confirm that providing such a list will not prohibit an entity from participating in the auction. (JUC)

Comment: Auction administration and participant application (s95912(d)(4)), (page 173): ARB proposed the following language: "An attestation that the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, has not been subject to any previous or ongoing investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation…."

CLFP finds this requirement, covering "the entity" and "all other entities" with which it is directly or indirectly associated, so broad as to be impossible to comply with because an entity cannot be expected to know if any such association "has been subject to previous or ongoing investigations". Moreover, even if investigations were undertaken in the past, or are even pending, an investigation does not imply wrong-doing.

Of even greater concern, one of the currently required attestations requires the company to confirm that it is not under investigation for potential violation of any rule, regulation or law associated with any commodity, securities, or financial market.

A company might not know that it is under investigation. Furthermore, the proposed amendments would expand this to also require that the company attest that none of its corporate associations is similarly under investigation. This is clearly regulatory over-reach, unreasonable, and will place a burden on companies that is impossible to satisfy.

CLFP recommends the following: ARB should withdraw the proposed amendments that expand attestation requirements. Any agency could initiate an investigation, or any individual could request an investigation or initiate a lawsuit leading to an investigation, and the entity would be unable to participate in an auction and to remain compliant with the Cap & Trade Regulations. If any attestation is required, it should only be pertaining to actual findings of violations of laws pertaining to the Cap & Trade regulation by the attesting party and not its associates. (CLFP 1)

Comment: The amendment would change a disclosure requirement into an attestation requirement. We're concerned that this is a significant change in the rules.

We're participating in an auction. And if an entity has any kind of an investigation, whether it's warranted or not, that that could bar that entity from participating in the auction.

We would prefer to see that this amendment be limited to either eliminate the attestation or limit the scope of the attestation so that it would cover fewer possible investigations. (LADWP 2)

> **Response:** Based on stakeholder concerns with the 45-day language in section 95912(d)(4) having an unlimited time frame for which the attestation disclosure would cover and the value of information on old investigations, ARB staff has amended section 95912(d)(4) in the 15-Day Modifications to limit the attestation disclosure to a period of 10 years and to limit the scope of the attestation disclosure with respect to corporate associates to investigations related to markets most closely related to the Cap-and-Trade program: other carbon markets, electricity or fuel markets. The revised 15-day language makes clear that the attestation must be updated to reflect a change in the status of an ongoing investigation. This change is intended to simplify completing the attestation disclosure for subsequent auctions.
>
> Stakeholder comments reflected concerns that Section 95912(d)(5) would prohibit entities disclosing a prior investigation or an ongoing investigation from participating in that auction. The text in this section says "….may be denied participation in the auction." ARB staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word "may" would instead read "shall." ARB staff will carefully evaluate the information in the more limited attestation disclosure, along with any other changes to information in listed in Section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation of all information required to be submitted pursuant to section 95912(d)(4).

Bid Guarantees

H-1.8. Multiple Comments: Auction Administration/Bid Guarantee (S95912(j)(1)(B), pg. 175): ARB has proposed the following language: "A bid guarantee submitted in any form other than cash must be payable within one business day of payment request." This seems, even with the advent of electronic transfers, an overly aggressive requirement. Certainly payment and reconciliation must be done promptly, but systems and people do fail and some provision needs to be made for the "normal course of business".

> **Recommendation:** WSPA recommends that the period be five working days to account for weekends, holidays etc.

Bid Guarantee Penalties and Restrictions: Section 95912 (j)(5)(D) is a new rule which states that if the bid guarantee is less than the maximum value of the bids to be submitted, it would result in a violation pursuant to section 95914. Under section 95914, the Executive Officer may impose significant penalties on the entity, including restricting its participation at an unspecified number of future auctions. Under the auction rules in section 95911 (e)(3) and 95912 (j)(10), the auction operator already has the authority to reject bids that exceed the bid guarantee. Considering this action, which could occur inadvertently, to be a violation with significant penalties seems excessive and unnecessary.

Recommendation: Eliminate 95912 (j)(5)(D). The auction administrator should reject all bids in excess of the bid guarantee. (WSPA 1)

Comment: The proposed regulation order proposed modification to bid guarantees that are not cash should be altered: The Proposed Regulation Order includes a new provision on page 175 that states that any bid guarantee that is not provided in the form of cash must be payable within one business day of a payment request. While SMUD understands that the ARB desires swift payment protocols in order to facilitate settlements, one business day is restrictive for many forms of bid guarantee still allowed by the Cap-and-Trade regulations. For example, a certified letter of credit is normally payable in two business days, and at times it may take three business days to complete the transaction. It is unclear to SMUD why settlements from a quarterly auction must be finalized as quickly as the modification in the Proposed Regulation Order suggests. SMUD recommends that the time period allowed for this be modified as follows:

> 95912(j)(3): A bid guarantee submitted in any form other than cash must be payable within three ~~one~~ business days of payment request. (SMUD 2)
>
> **Response:** Staff agrees that requiring non-cash bid guarantees to be payable within one business day may be too little time in some circumstances. After consulting with the Financial Services Administrator, and recognizing that undue delay in settling an auction is not desirable, the requirement has been changed in 15-day language to three business days. Staff believes that three business days is sufficient to ensure an adequate processing of bid guarantees, and declines to modify this to five business days. With respect to section 95912(j)(5)(D) regarding bid guarantees and rejecting bids which exceed the bid guarantee, staff agrees that this provision is not needed and deleted it in the 15-day changes.

Holding Limit/Purchase Limit

H-1.9. Comment: Holding Limit Allocation: Section 95914(d)(2) is proposed to state that “Entities that are part of a direct corporate association must allocate shares of the purchase limit amongst themselves. This allocation of the shares of the purchase limit must be provided pursuant to section 95830”. This requirement seems unnecessary when all entities with a direct corporate association are consolidated pursuant to section 95833(f)(1). Also reference to section 95830 appears incorrect.

> **Recommendation:** Modify 95914(d)(2) to state “Entities that are part of a direct corporate association and have opted out of consolidation pursuant to section 95833 (f)(3) must allocate shares of the purchase limit amongst themselves. This

allocation of the shares of the purchase limit must be provided pursuant to section ~~95830~~ 95833 (f)(3)(C)(2)." (WSPA 1)

Response: Thank you for the comment. ARB staff has corrected this non-substantial error following Board approval of the Regulation.

H-1.10. Comment: Section 95912(d)(4)(C), (D): The proposed amendment would require a covered entity's auction participation application to include an allocation of the "purchase limit" and the "holding limit" among members of a "direct corporate association" as defined in Section 95833. The Staff states that the purpose of this provision is to require covered entities to report any change in the distribution of the purchase limit and/or the holding limit among corporate associates. Staff Report at p. 176. Whether or not this proposed amendment is adopted, each of the covered entities with a "direct corporate association" that is subject to the purchase limits and the holding limits should be permitted to establish its own subaccount for compliance and retirement in accordance with Section 95856(c), and should be allowed to transfer compliance instruments between and among the compliance accounts for each covered entity, subject to the overall holding limits. This approach provides entities that have a direct corporate association, and that are subject to the purchase and holding limits, greater flexibility in the timing and allocation of compliance instruments for retirement. The Regulation should be amended to include a provision that allows covered entities to establish their own subaccounts for compliance and retirement as discussed above. (SHELL 1)

Response: Covered entities with a direct corporate association are able to establish their own compliance and retirement accounts. This is accomplished by choosing to opt-out of account consolidation. Opting-out of account consolidation results in the directly associated entities maintaining separate CITSS accounts, including separate compliance and retirement accounts. For technical and policy reasons, compliance instruments in a compliance account may only be withdrawn by the state of California when a compliance obligation is due. Thus, neither direct corporate associates, nor anyone else, may transfer compliance instruments from their compliance accounts.

Notification of Advisors and Consultants

H-1.11. Multiple Comments: A number of additional and overly burdensome administrative requirements have been amended in the following sections of the regulation: Registration of Cap-and-Trade Consultants and Advisors (95830(c) (1) (J))

It is unclear to CCEEB how many of these requirements benefit the program and their inclusion presents a significantly increased administrative burden on compliance entities in an already complicated regulation. CCEEB would recommend eliminating these changes, as they do not appear necessary. (CCEEB 1)

Comment: Consultants and advisors can work with entities on a range of issues and matters, from advising on reporting deadlines to potential use of allowance values. Requiring reporting to CARB about all such individuals is not warranted unless those individuals have access to confidential or restricted information, or direct control over compliance instrument disposition. Further, a strict reading of the current language could impose upon registered entities a requirement to report and disclosure all employees of their various consultants and advisors or be in violation of the Regulation. This request could place a significant burden on the registered entity to report every employee of an advisor or consultant that may review the company's file, even assuming the registered entity knows who those individuals may be.

While acknowledging CARB's concerns, the Proposed Amendments place an unreasonably broad burden on registered entities. As discussed above with regard to employee information disclosures, the restrictions and burdens should be placed on individuals registering for CITSS as voluntarily associated entities; with that information, on a case-by-case basis, CARB would be notified of relevant information, and can make a determination regarding which individuals should not be permitted to participate in CITSS. NCPA urges the Board to strike in its entirety the Proposed Amendment that would add section 95923 to the Regulation.

> **Recommendation:** In the alternative, should the section remain, it should be revised to provide that:
>
> (a) A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program. Cap-and-Trade Consultants and Advisors do not include attorneys. (NCPA 1)

Comment: Disclosure of cap and trade consultants and advisors: Section 95923 New Section 95923 sets forth new disclosure requirements for "Cap and Trade Consultants and Advisors," which are defined as a person or entity that is not employed by an entity registered in the cap and trade program, "but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program."

CPEM requests that ARB clarify draft section §95923 in a variety of respects. First, CPEM believes the phrase "advises or consults with the entity regarding compliance with the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program" is too broad as drafted, and could improperly capture consultants advising on non-material issues. (CPM 1)

Comment: The ARB should modify the rules for disclosure of cap-and trade consultants and advisors: Section 95923 of the Proposed Regulation Order defines "Cap-and-Trade Consultant or Advisor" and would require entities registered in cap-and-trade program to disclose identifying information about cap-and-trade consultants or advisors, along with a brief description of the work performed. SCE appreciates the sensitivity to rules governing confidentiality, such as the attorney-client privilege, which the proposed regulation language attempts to address in section 95923(a)(2) by limiting disclosure to a description that does not "violate any of the rules under which the Consultant or Advisor may be required to observe." Still, this proposed section opens the door to possible waivers of privilege, is administratively burdensome, and can easily lead many regulated entities to be unintentionally noncompliant. For example, must the regulated entity now monitor every consultant's employee or law firm associate that might be put on a bill -- and constantly update disclosures accordingly? There is no information released in this disclosure that would be useful to the ARB that cannot be obtained through a subpoena.

SCE proposes modifying the regulation language to require regulated entities to maintain records of such consultants or advisors and provide these records to the ARB upon their request, within 10 days of the request. (SCE 1)

Comment: The language of Section 95923 (Disclosure of Cap-and-Trade Contractors) should be modified so that the disclosures apply only to consultants who provide advice on transactions of compliance instruments.

> **Recommendation:** WPTF accordingly suggests the following changes to the language in Sections 95830(i) and (j) and Section 95923:
>
> §95923(a) A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program. (WPTF 1)

Comment: Definition of a "Cap-and-Trade Consultant or Advisor": SGEN agrees with ARB that the term "Cap-and-Trade Consultant or Advisor" should be defined within the Regulations, but the proposed language in section 95923(a) does not provide the clarity needed regarding the functions performed by this person or entity.

> **Recommendation:** SGEN therefore suggests the following revisions to section 95923(a) in order to avoid confusion when reporting the formation or termination of an advisor-client relationship:
>
> A "Cap-and-Trade Consultant or Advisor" is a person or entity that ~~is not an employee employed of an by entity registered in the cap and trade, but~~ is retained by an entity registered in the Cap-and-Trade Program, to provide information or advice related to auction bidding strategy, carbon instrument transactions, or assessment of the entity's holdings of carbon instruments ~~the Cap and Trade Program, specifically for the entity registered in the Cap and Trade Program~~. A permanent employee of the hiring entity is not to be considered a "Cap-and-Trade Consultant or Advisor."

The amendments suggested above would negate the need for "a brief description of the work performed by the Consultant or Advisor..." as proposed for section 95923(b)(2). Thus, along with the changes noted above, proposed section 95923(b)(2) should be deleted from the proposed amendments. (SEMPRA 1)

Comment: Disclosure requirements should be modified or clarified to ensure protection of the attorney-client privilege and duty of confidentiality: clarification is necessary regarding an entity's obligation to provide a description of work performed by a consultant or advisor: An entity registering to participate in the Cap-and-Trade Program must provide detailed information for individuals serving as a Cap-and-Trade Consultant or Advisor. Specifically, an entity employing a Cap-and-Trade Consultant or Advisor must provide, among other things, "a brief description of the work performed ... to the extent disclosure of such a description does not violate any other rules under which the Consultant or Advisor may be required to observe." In the Proposed Regulation Order, "Cap-and-Trade Consultant or Advisor" is broadly defined as "a person or entity that is not an employee of an entity registered in the cap-and-trade, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program." On its face, a "Cap-and-Trade Consultant or Advisor" would include attorneys retained by entities to provide legal and other advice regarding the Cap-and-Trade Program.

We note that the provision that the disclosure must not violate any rules that the Consultant or Advisor is required to observe is newly proposed language that did not appear in CARB staffs July 2013 Draft Amendments. Presumably, this provision is intended to address stakeholders' concerns that section 95923 would require entities to disclose documents or information protected by the attorney-client privilege. While CARB staff's modified section 95923(b)(2) is an improvement in this regard, it does not specifically exclude disclosure of information that would violate the attorney-client privilege. We believe that such a modification to the Proposed Draft Order is necessary in light of the essential function that the attorney-client privilege serves in the American legal system.

The attorney-client privilege broadly protects confidential communications made between attorneys and their clients, and "has been a hallmark of Anglo-American jurisprudence for almost 400 years." Expressly protected by California statute, the attorney-client privilege is critical to "safeguard[ing] the confidential relationship between clients and their attorneys so as to promote full and open discussion of the facts and tactics surrounding individual legal matters." Indeed, by protecting confidentiality and encouraging open and complete communication between clients and lawyers, the attorney-client privilege ensures that attorneys can provide clients with candid advice and effective representation. The privilege undoubtedly provides an essential legal safeguard that the Regulation should not compromise. Thus, we encourage CARB staff to modify the Draft Regulation Order to make expressly clear that any "description of the work performed" required by section 95923(b)(2) does not include any information protected by or subject to the attorney-client privilege.

Auction advisor disclosure requirements should be modified to safeguard the attorney-client privilege and avoid violation of duty of confidentiality: Section 95914 requires an entity participating in an auction who has "retained the services of an advisor regarding auction bidding strategy" to: (1) inform CARB staff of (a) the identity of the advisor, (b) the advisor's employer, and (c) the advisor's contact information; and (2) provide CARB staff an attestation of the completeness of such disclosure. In addition, however, such an auction advisor must provide CARB staff, in writing, at least 15 days before the auction: 1. Names of the entities participating in the Cap-and-Trade Program that are being advised; 2. Description of advisory services being performed; and 3. Assurance under penalty of perjury that advisor is not transferring to or otherwise sharing information with other auction participants.

Under the Proposed Regulation Order, if an auction participant retained an attorney to advise it regarding some aspect of the auction bidding process, section 95914(c)(3)(D) would require the attorney (not the entity) to provide a description of the advisory services performed for such an entity. In doing so, however, the attorney would violate the attorney-client privilege and the separate duty of confidentiality required by the California Rules of Professional Conduct.

As discussed above, the attorney-client privilege protects confidential communications between clients and lawyers. The right to assert the privilege belongs to the client. However, "the attorney is professionally obligated to claim it on behalf of his client's behalf whenever the opportunity arises unless he has been instructed otherwise by the client." The essential importance of such protection is further evidenced by courts' inability to compel any waiver of the attorney client privilege. Given the significance of the privilege in the American legal system, an attorney who willfully violates the attorney-client privilege may face disqualification from practicing law and incur other sanctions. As written, section 95914(c)(3)(D) would require the attorney, not the client-holder of the privilege, to disclose privileged communications to CARB.

In addition, attorneys are subject to a separate ethical duty of confidentiality, which is even broader than the attorney-client privilege. The duty of confidentiality extends to cover all of the information gained within the scope of the attorney-client professional relationship that the client has requested be kept secret, or the disclosure of which could be harmful or embarrassing to the client. Significantly, a lawyer must "maintain inviolate the confidence, and at every peril to himself or herself to preserve the secrets, of his or her client." While the attorney-client privilege applies in judicial and other proceedings in which an attorney may be called as a witness or otherwise be compelled to produce evidence concerning a client, the duty of confidentiality prevents an attorney from revealing a client's confidential information-even when not confronted with such compulsion. Like the attorney-client privilege, the duty of confidentiality "contributes to the trust that is the hallmark of the client-lawyer relationship," ensuring full and frank communication between client and lawyer, and enabling the lawyer to provide effective counsel to the client. The disclosure requirements contemplated by section 95914(c)(3)(D), however, would require an attorney to violate this duty.

Absent an express exclusion of attorneys from this provision, to avoid running afoul of such disclosure requirements, outside counsel may be forced to refrain from providing any advice to entities regarding the auction bidding process and potentially other related aspects of the Cap-and-Trade Program. As a result, section 95914(c)(3)(D) could have a "chilling effect" on attorneys' ability to advise clients in this regard, which would severely limit the ability of clients to receive complete legal and other advice in such matters. To avoid undermining the attorney-client relationship in this regard, we encourage CARB staff to expressly exclude attorneys from the disclosure requirements in section 95914(c)(3)(D). While CARB staff included this provision "to provide ARB with greater oversight of advisors," we believe such modification to the Regulation will not undermine or affect CARB staff's ability to maintain such regulatory oversight. In light of these considerations, we encourage CARB staff to make every effort to protect the attorney-client privilege and to ensure that attorneys are not required to disclose privileged or client confidential information under the Regulation.

Finally, we note that the auction advisor described in section 95914 would appear to satisfy the definition of "Cap-and-Trade Consultant or Advisor" in section 95923, described above. Thus, for consistency and clarity, it appears that references to "advisor" in section 95914 should be changed to "Cap-and-Trade Consultant or Advisor".

Separately; we request that CARB staff modify or clarify certain disclosure requirements under the Regulation to ensure protection of the attorney-client privilege and to avoid any potential requirement for attorneys to breach their ethical duty of confidentiality to their clients. Absent such modifications, outside attorneys may be forced to refrain from providing any advice to clients in order to avoid the risk of sanctions, or even disbarment.

Recommendation: Exhibit A: Recommended Amendments To Protect Attorney-Client Privilege And Duty of Confidentiality

§ 95923. Disclosure of Cap-and-Trade Consultants and Advisors

(b) An entity employing Cap-and-Trade Consultants or Advisors defined per 95923(a) must disclose the following information for each Cap-and-Trade Consultant or Advisor, unless already disclosed pursuant to section 95914(c)(3):

(2) A brief description of the work performed by the Consultant or Advisor, to include information sufficient to explain the entity's evaluation of the measures contained in section 95923(a) used to determine the Consultant or Advisor relationship, without <u>compromising the confidentiality of the attorney-client relationship or any duty of confidentiality afforded by rule, regulation, case law or statute</u> to the extent disclosure of such a description does not violate

any other rules under to which the entity is entided or the Consultant or Advisor may be required to observe. (PH 1)

Comment: Section 95923 has improved from the discussion draft, but the section should identify attorneys as separate from consultants and advisors. To protect attorney client privilege, attorneys should be excluded from providing data in Section 95923(b)(2) as follows.

Recommendation: Modifications to 95923 (Disclosure of Cap-and-Trade Contractors):

(a) A "Cap-and-Trade Attorney, Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the cap-and-trade, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program.

(b) An entity employing Cap-and-Trade Attorneys, Consultants or Advisors defined per 95923(a) must disclose the following information for each Cap-and-Trade Attorney, Consultant or Advisor, unless already disclosed pursuant to section 95914(c)(3):

(1) Information to identify the Cap-and-Trade Attorney, Consultant or Advisor, including:

(A) Name;

(B) Contact information;

(C) Physical work address of the Cap-and-Trade Consultant or Advisor; and

(D) Employer, if applicable.

(2) A brief description of the work performed by the Consultant or Advisor, to include information sufficient to explain the entity's evaluation of the measures contained in section 95923(a) used to determine the Consultant or Advisor relationship, to the extent disclosure of such a description does not violate any other rules under which the Consultant or Advisor may be required to observe.

(c) The entity must disclose the information pursuant to section 95923(b) to the Executive Officer:

(1) When registering pursuant to section 95830;

(2) At any time after registering when a Contractual agreement pursuant to section 95923(a) is created;

(3) Within 30 days of a change to the information disclosed on Attorneys, Consultants or Advisors. (SEMPRA 2)

Comment: §95923. Disclosure of cap-and-trade consultants and advisors: The proposed amendments add a new section requiring registered entities to disclose specific information on "cap-and-trade consultants or advisors." A "cap-and-trade consultant or advisor" is broadly defined as "a person or entity that is not an employee of an entity registered in cap-and-trade, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity." It is not clear from CARB's rationale provided in the ISOR why CARB would require a description of services provided by the consultant or advisor as the requirement is not tailored toward addressing a specific concern. Per this proposed definition, this could include attorneys and consultants who provide advice regarding compliance with specific cap-and-trade provisions but do not have access or knowledge of the entity's compliance instrument position or strategy with respect to procurement or sale of compliance instruments.

Attorneys are bound by long recognized obligations and privileges to prevent the ready disclosure of communication reposed in the attorney, such as the duty of confidentiality, the attorney-client privilege, and the attorney-work product doctrine. An attorney's duty of confidentiality is "one of the principal obligations" of the attorney-client relationship. Flatt v. Sup. Ct. (Daniel)(1994) 9 Cal.4th 275, 289. The obligation is "a very high and stringent one." Id. In addition, the purpose of the attorney-client privilege is to "encourage full and frank communications between attorneys and their clients and thereby promote broader public interests in the observance of law and administration of justice." Upjohn Co. v. United States (1981) 449 US 383, 389; California Evidence Code §950 et seq. Furthermore, "[a] writing that reflects an attorney's impressions, conclusions, opinions, or legal research or theories" is generally protected as well. Vapnek, Tuft, Peck & Weiner, Cal. Prac. Guide: Professional Responsibility (Rutter Group 2012), §7:385.2 citing Cal. Code Civ. P. §2018.030; Rico v. Mitsubishi Motors Corp. (2007) 42 Cal.4th 807, 814 (additional citations omitted). The broad language of the ARB's proposed definition appears to require the disclosure of privileged communications, and possibly work product to the ARB in contravention of these long standing attorney obligations and client privileges.

Moreover, government officials and employees, including government attorneys, are subject to additional rules under the "Political Reform Act of 1974", which established the Fair Political Practices Commission (FPPC) and requires the disclosure of financial interests. Government Code §81000 et seq. and, the FPPC has created new rules and forms for consultants disclosing their interests. GARB should look to the efforts of the FPPC to help it achieve its goals in a focused manner.

Recommendation: LADWP recommends that the amendments be clarified to exclude attorneys as follows in §95923(a):

A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program. Cap-and-Trade Consultants and Advisors do not include attorneys.

In addition, LADWP recommends that CARB include a simple form in the Compliance Instrument Tracking System Service (CITSS) for entities to complete if they have retained consultants that have access to information contained in the CITSS. (LADWP 1)

Comment: And, as discussed below with reference to Section 95923, attorneys (including attorneys employed by a cap and trade entity) are subject to regulation under state (and/or provincial) bars, have ethical obligations to protect client confidentiality, and are subject to strict conflict of interest rules.

Recommendation: At the least, CPEM requests that this section be modified as follows:

"Names and contact information for all persons employed by the entity (other than legal counsel) in a capacity giving them access to material information on compliance instrument transactions or holdings, or involving them in material decisions on compliance instrument transactions or holdings, and which, by virtue of their job function, allows them to affect material transactions and strategy."

Second, CPEM requests that ARB clarify that this disclosure provision does not apply to attorneys, who are subject to regulation under state (and/or provincial) bars and have ethical obligations to protect client confidentiality and are subject to strict conflict of interest rules. Outside counsel frequently advise entities regarding compliance matters, some of which may be confidential and sensitive, and such attorneys may not be permitted under state bar rules to disclose that fact to other entities, including other existing or prospective clients. Moreover, to the extent outside counsel is engaged to provide advice with respect to compliance with ARB regulations, disclosing this fact to the ARB, as would be required pursuant to draft Section 95923(b)(2), may operate as a waiver of the attorney–client privilege, rendering access to counsel ineffective. Given the overbroad definition discussed above, and given that attorneys are subject to express regulation with respect to client confidentiality and conflict of interest, and the longstanding public policy of encouraging the opportunity to seek advice of counsel, CPEM requests that Section 95923(a) be modified as follows:

> A “Cap-and-Trade Consultant or Advisor” is a person or entity<u>(other than an attorney providing legal advice)</u> that is not an employee of an entity registered in the cap-and-trade, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program <u>in a manner that the Consultant or Advisor receives confidential information regarding the entity’s auction or compliance instrument holding strategy.</u> (CPM 1)

Comment: Disclosure of cap-and-trade contractors: provisions regarding the disclosure of cap-and-trade contractors should specifically exclude lawyers.

NCPA appreciates the fact that the Proposed Amendments reflect changes to section 95923 from what was set forth in the Discussion Draft. As expressed in earlier comments, the proposed addition of section 95923(a) included an ambiguous and potentially broad definition of individuals that “advise and consult.” The Proposed Amendments narrow the scope of this request, but is still problematic. As NPCA understands it, CARB is concerned that auction and other advisors could be working for more than one registered entity, and thereby have access to information that could then be used for some kind of malfeasance. NCPA further understands from meeting with CARB staff that the intent of this section is not to obtain information regarding attorneys working with registered entities, nor to compel entities to disclose information that would otherwise be privileged. NCPA appreciates this clarification and urges the Board to include it within the list of proposed 15-day changes to the Regulation. However, that does not address other concerns stemming from this Proposed Amendment. (NCPA 1)

Comment: Section 95923. Disclosure of cap-and-trade consultants or advisors: The proposed definition for a “Cap-and-Trade Consultant or Advisor” is too broad and could result in the waiver of attorney-client privilege. Attorneys are already subject to strict conflict of interest rules and therefore do not need to be captured in this definition. The Joint Utilities recommend Section 95923(a) explicitly exclude attorneys. (JUC)

Comment: Clarify that consultant and advisor disclosure requirements do not include attorneys: Proposed new section 95923 requires registered entities to report to the ARB details on “Cap-and-Trade Consultants or Advisors”, defined as a person or entity that is not an employee of the registered entity but is paid for information or advice related to the Cap-and-Trade Program for the registered entity.

The reference to advice related to the Cap-and-Trade Program would, on its face, include attorneys advising clients on the program. If an entity discloses the work performed by its attorneys under section 95923(b)(2), this may constitute a waiver of attorney-client privilege. Entities may wish to preserve this privilege. Furthermore, attorneys are already subject to stringent confidentiality and conflict of interest requirements under the California Rules of Professional Conduct. Therefore, there is no need for this section to include attorneys. ARB staff members confirmed in a teleconference on October 10, 2013, that this section is not intended to cover attorneys.

This section should be revised to clearly exclude attorneys. In addition, to reduce the reporting burden a simple online form should be developed, perhaps in the tracking system, for an entity to complete if it engages a consultant or advisor.

> **Recommendation:** SCPPA's proposed changes to section 95923(a) are set out below:
>
> (a) A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the ~~c~~Cap-and Ttrade Program, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program. Cap- and-Trade Consultants and Advisors do not include attorneys. (SCPPA 1)

Comment: PG&E also recommends the following change to Section 95923(a)(1): A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the cap-and-trade, but ~~is paid~~ retained under contract by an entity registered in the Cap-and-Trade Program for the purpose of providing information or advice related to the Cap-and-Trade Program specifically for such entity. Cap-and-Trade Consultants and Advisors do not include attorneys. (PGE 2)

Comment: (J) Information required under section 95923 for individuals serving as Cap-and-Trade Consultants and Advisors for entities participating in the Cap-and-Trade Program. (WPTF 1)

Comment: Most recently, ARB proposed in Section 95830: "Information required under section 95923 for individuals serving as Cap-and-Trade Consultants and Advisors for entities participating in the Cap- and-Trade Program." WSPA opposes proposed amendments that would require registration of the names and contact information for all "individuals serving as Cap-and-Trade Consultants and Advisors for entities participating in the Cap-and-Trade program" because the requirements are overly broad and it is unclear who this would apply to. In cases where companies do use advisors and consultants, it is common business practice for the contracts between the company and consultant to include confidentiality provisions.

Again, WSPA does not understand what ARB would do with this information or how ARB would effectively manage it. This provision is overly broad and does not provide any additional insights into the market. How, for example would ARB propose to address "regulation" of law firms or accounting firms that have multiple clients, each, presumably, under a specific confidentiality agreement?

> **Recommendation:** ARB should remove this requirement. The requirement to divulge information about advisors, whether paid or not, is intrusive, unnecessary and violates the legal rights of entities to be free to enter into contracts with appropriate contractors on terms of their choice, which terms frequently contain trade secret protecting confidentiality requirements.

The requirement could also adversely affect the market in which contractors compete for clients. In addition, given the number of restrictions already in-place and probably difficult to enforce, this requirement is not appropriate. (WSPA 1)

Response: As indicated in the Staff Report, ARB staff believes the information required to be disclosed by section 95923 is necessary to ensure effective monitoring and oversight of entities that have access to information from multiple entities participating in the Cap-and-Trade Program. In response to stakeholder comments, however, the definition of "Cap-and-Trade Consultant or Advisor" pursuant to section 95923 has been modified in 15-day changes to be more specific, and to correspond to existing "services" as already specified in the Regulation. As defined in modified section 95923(a), a "Cap-and-Trade Consultant or Advisor" would be a person or entity (excluding employees of the registered entity) who provides the services listed in section 95979(b)(2) of the Cap-and-Trade Regulation, or section 95133(b)(2) of the MRR, to the registered entity. This would include outside counsel hired by a registered entity to the extent that outside counsel is providing any of those services. As specified in sections 95979(b)(2) and 95133(b)(2), these services are:

Section 95979(b)(2)	Section 95133(b)(2)
(A) Designing, developing, implementing, reviewing, or maintaining an inventory or offset project information or data management system for air emissions, unless the review was part of providing GHG offset verification services; (B) Developing GHG emission factors or other GHG-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) GHG analysis that includes offset project specific information; (C) Designing energy efficiency, renewable power, or other projects which explicitly identify GHG reductions and GHG removal enhancements as a benefit; (D) Designing, developing, implementing, internally auditing, consulting, or maintaining an offset project resulting in GHG emission reductions and GHG removal enhancements; (E) Owning, buying, selling, trading, or retiring shares, stocks, or ARB offset credits or registry offset credits from the offset project; (F) Dealing in or being a promoter of ARB offset credits or registry offset credits on behalf of an Offset Project Operator or Authorized Project Designee; (G) Preparing or producing GHG-related manuals, handbooks, or procedures specifically for the Offset Project Operator or Authorized Project Designee;	(A) Designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing greenhouse gas verification services; (B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) greenhouse gas analysis that includes facility specific information; (C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit; (D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emissions reduction or GHG removal offset project as defined in the cap-and-trade regulation; (E) Owning, buying, selling, trading, or retiring shares, stocks, or emissions reduction credits from an offset project that was developed by or resulting reduction credits are owned by the reporting entity; (F) Dealing in or being a promoter of credits on behalf of an offset project operator or authorized project designee where the credits are owned by or the offset project was developed by the reporting entity;

(H) Appraisal services of carbon or GHG liabilities or assets;
(I) Brokering in, advising on, or assisting in any way in carbon or GHG-related markets;
(J) Directly managing any health, environment or safety functions for the Offset Project Operator or Authorized Project Designee;
(K) Bookkeeping or other services related to the accounting records or financial statements;
(L) Any service related to information systems, including 14001 certification, unless those systems will not be reviewed as part of the offset verification process;
(M) Appraisal and valuation services, both tangible and intangible;
(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the information reviewed in formulating the Offset Verification Statement will not be reviewed as part of the offset verification services;
(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
(P) Any internal audit service that has been outsourced by the Offset Project Operator or Authorized Project Designee that relates to the Offset Project Operator's or Authorized Project Designee's internal accounting controls, financial systems, or financial statements, unless the systems and data reviewed during those services, as well as the result of those services will not be part of the offset verification process;
(Q) Acting as a broker-dealer (registered or unregistered), promoter, or underwriter on behalf of the Offset Project Operator or Authorized Project Designee;
(R) Any legal services; and
(S) Expert services to the Offset Project Operator or Authorized Project Designee or a legal representative for the purpose of advocating the Offset Project Operator's or Authorized Project Designee's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related

(G) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting entity;
(H) Appraisal services of carbon or greenhouse gas liabilities or assets;
(I) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
(J) Directly managing any health, environment or safety functions for the reporting entity;
(K) Bookkeeping or other services related to accounting records or financial statements;
(L) Any service related to development of information systems, including consulting on the development of environmental management systems, such as those conforming to ISO 14001 or energy management systems such as those conforming to ISO 50001, unless those systems will not be part of the verification process;
(M) Appraisal and valuation services, both tangible and intangible;
(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;
(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
(P) Any internal audit service that has been outsourced by the reporting entity or offset project operator that relates to the reporting entity's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification process;
(Q) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the reporting entity;
(R) Any legal services;
(S) Expert services to the reporting entity or a legal representative for the purpose of advocating the reporting entity's interests in litigation or in a regulatory or administrative proceeding or investigation.
(T) Verification services that are not conducted in accordance with, or equivalent to, section 95133 requirements, unless the systems and data reviewed during those services, as well as the result of those services, will not be part of the verification process.

entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company	"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

Various commenters raised concerns with respect to whether section 95923 would require the disclosure of confidential, privileged attorney-client communications. This was not staff's intent, and staff agrees with the multiple comments asserting the long history and legal protections for confidential, privileged legal advice and communications provided by attorneys to their clients. However, under existing legal precedent, ARB staff understands the rule protecting confidential attorney-client communications applies to the communications, and generally not to the existence of the attorney-client relationship in and of itself. In response to these comments, staff has deleted section 95923(b)(2) in 15-day changes to remove the previously proposed language requiring a "description of services" to be disclosed. This amendment ensures that protected attorney-client communications are not in fact disclosed. As amended, the only information required to be disclosed under section 95923 is the name, contact information, physical work address, and employer of the retained Consultant(s) or Advisor(s).

Moreover, regarding commenters' concerns about attorneys disclosing any information themselves, section 95923 applies not to the Consultant or Advisor, but to the entity which contracts with such Consultant or Advisor. Only the registered entity is required to disclose the names, contact information, physical work address, and employer (if applicable) of any retained Consultants or Advisors.

In addition, multiple commenters have raised questions about which types of "legal services" being provided by outside counsel would require a disclosure. As specified in section 95923(a), these would include those services provided specifically for the entity registered in the Cap-and-Trade Regulation. With respect to legal services, staff does not intend this language to apply to legal advice specifically related to enforcement-related matters initiated by ARB or another regulatory body, white collar criminal proceedings, or legal support in preparing individual and entity registration in CITSS. Registered entities however would have to disclose the nature and status of investigations (ongoing and for the previous 10 years) associated with any commodity, securities, environmental, or financial market pursuant to section 95912(d)(4)(E).

Furthermore, staff believes it is important to understand that not all services provided by an attorney are considered "legal services." If an attorney is providing non-legal services, such as brokering, auditing, financial advice, bid strategy, or other business advice, these would not constitute legal services. The attorney would be operating in a non-lawyer capacity in giving this advice. In these cases, where an attorney provided non-legal services listed in section 95979(b)(2) of the Cap-and-Trade Regulation or section 95133(b)(2) of the MRR to the registered entity, the registered entity would have to disclose the Consultant or Advisor information as required under section 95923. If such non-legal service related specifically to auction bidding strategy, the attorney would be required to disclose as a Consultant or Advisor under section 95914(c)(3).

Finally, section 95830(f) has been modified to reflect the need to disclose personnel who have authority involving compliance instruments; and. staff continues to explore additional functionality in CITSS for entities to include information about retained Consultants and Advisors.

H-1.12. Comment: Requirement to Inform ARB of an Advisor: Section 95914(c)(3)(C) has been added to include the requirement that any entity that has retained the services of a "Cap-and-Trade Consultant or Advisor" must inform ARB of the advisor's retention, "and identify the advisor...and provide an attestation by the Primary Account Representative of the entity retaining the advisor…"

The notification required under section 95914(c)(3)(C) should be accepted from the Alternate Account Representative *or* the Director or Officer who is responsible for the conduct of the entity as well as from the Primary Account Representative.

Recommendation: Therefore, section 95914(c)(3)(C) should be revised as follows:

Any entity that has retained the services of an advisor must inform ARB of the advisor's retention, and identify the advisor, the advisor's employer, the advisor's contact information, and provide an attestation by the Primary Account Representative<u>, the Alternate Account Representative, or Director or Officer who</u> <u>is responsible for the conduct of the entity.</u> (SEMPRA 1)

Response: In response to stakeholder comments, staff has stricken section 95914(c)(3)(C) in 15-day changes in order to prevent duplicative or conflicting requirements that exist in section 95923. As such, this comment is now moot and no further changes are needed.

H-1.13. Comment: Section 95914(c)(1)(A) prevents disclosure of intent to participate, etc. to entities other than those identified in section 95914(c)(2). The institution providing the bid guarantee will know that the registered entity intends to participate in the auction. An entity participating in an auction has to provide a bid guarantee provided by an external entity.

Recommendation: Edit language to allow, at a minimum, disclosure to the financial or other institution that the participating entity uses to satisfy the bid guarantee requirements. (WSPA 1)

Response: Staff does not agree with the recommendation. Section 95914(c)(1)(D) explicitly includes bid guarantee information provided to the financial services administrator. As such, inclusion again in section 95914(c)(2) would be redundant.

H-1.14. Comment: Requirement to Inform ARB of a Client: Section 95914(c)(3)(D) has been added in the proposed amendments to impose an obligation on an "advisor" who has clients participating in the Cap-and-Trade Program to inform ARB 15 days prior to each carbon auction of the names of its clients and the advisory services being performed.

This new requirement would not only be overly burdensome to those that provide Cap-and-Trade Consultant or Advisor services, it is also duplicative of the information disclosure requirements imposed on entities under sections 95914(c)(3)(C), and 95923(b) and (c). Proposed section 95914(c)(3)(C) already specifies that "Any entity that has retained the services of an advisor must inform ARB of the advisor's retention," therefore, there should be no gap in notification of an advisor-client relationship to ARB by certain entities. Section 95914(c)(3)(D) should be removed from the proposed amendments. (SEMPRA 1)

Response: In order to avoid duplicative requirements, staff removed section 95914(c)(3)(C) in the 15-day changes. Formerly proposed section 95914(c)(3)(D) has been renumbered to section 95914(c)(3)(C) in the 15-day Regulation text. The requirement under this provision provides a second data point to validate information presented in other disclosure requirements, providing greater market oversight of entities that may have access to market sensitive information. Staff does not agree that Section 95914(c)(3)(D) (renumbered to section 95914(c)(3)(C) in the 15-day Regulation text) should be deleted, as this would remove the requirement for disclosure by Consultants or Advisors, which is separate from the disclosure requirement by the covered entity in section 95923.

H-1.15. Comment: If a bidding advisor fails to provide information to ARB, the entity engaging the bidding advisor should not be penalized: Revised section 95914(c)(3) requires information regarding bidding advisors to be provided to the ARB by both the entity engaging the bidding advisor and the bidding advisor itself. Section 96010 (Jurisdiction) does not appear to provide the ARB with authority to regulate bidding advisors, as they will not be registering for accounts, holding compliance instruments, verifying offsets, or receiving compensation from transfers of compliance instruments. If a bidding advisor fails to provide the ARB with the information requested under section 95914(c)(3)(D), the ARB should not penalize the covered entity in place of the bidding advisor. A bidding advisor may work as an independent contractor to several covered entities, and the covered entities will not necessarily be aware of, and should not be liable for, the acts or omissions of independent contractors. (SCPPA 1)

> **Response:** Section 95914(c)(3)(C) has been stricken during the 15-day changes so that section 95914(c)(3) only requires disclosure by the consultant or Advisor. Covered entities will be liable for omission of disclosure of Consultants or advisors as per section 95923. Regarding ARB's jurisdiction to require advisors to disclose their clients, ARB staff notes this is an existing requirement.

H-1.16. Multiple Comments: CPEM also requests that the ARB clarify whether a "Cap-and-Trade Consultant or Advisor" as used in Section 95923(a) is the same or different than an "auction bid advisor" as used in new section 95914(c)(2)(B) or an "advisor regarding auction bidding strategy" as referenced in 95914(c)(3). If these definitions are the same, then CPEM submits that new Section 95923 is entirely unnecessary, as such entities are already required to be disclosed to the Executive Officer. If such advisors are different, then CPEM requests specific clarification as to when the different definitions of advisor apply. (CPM 1)

Comment: And finally, with regard to the employee disclosures and the contractors, we appreciate the proposed revisions or staff's acknowledgement that they want to continue to work with stakeholders and ask that you adopt that portion of the resolution. (NCPA 2)

Comment: Disclosure of Cap-and-Trade Consultants or Advisors: PG&E suggests minor changes to Sections 95914 and 95923 concerning Cap-and-Trade Consultants and Advisors to clarify applicable provisions in the proposed Regulation. PG&E also suggests that ARB globally replace references to "consultants" and "advisors" with "Cap- and-Trade Consultants or Advisors" to ensure the consistency of the Regulation.

> **Recommendation:** Because the amendments do not define "advisors," PG&E has provided an "advisor" definition for ARB's consideration.
>
> Section 95914(c)(3): If an entity participating in an auction has retained the services of <u>an Cap-and-Trade Consultant or Advisor, which means a firm or an individual not employed by the entity for the purpose of advising the entity on auction bidding strategy,</u> then...
>
> Section 95914(c)(3)(A): The entity must ~~ensure~~ <u>caution the Cap and Trade Consultant or Advisor against</u> ~~the advisor~~ transferring information to other auction participants or coordinating the bidding strategy among participants... (PGE 2)
>
> **Response:** In response to comments, staff changed the text in Section 95914(c)(2)(B) and 95914(c)(3) to refer consistently to "Cap-and-Trade Consultant or Advisor" as defined in Section 95923. Staff also revised Section 95914(c) by deleting the former section 95914(c)(3)(C) that required entities to disclose whether they had retained a Cap-and-Trade Consultant or Advisor; this

requirement is now contained in Section 95923 (the “new” 95914(c)(3)(C) requires certain disclosures by the Consultant or Advisor, not the entity). Section 95923 also defines a Cap-and-Trade Consultant or Advisor and cross-references Section 95979(b)(2) of the Cap-and-Trade Regulation and Section 95133(b)(2) of MRR, defining the services a Cap-and-Trade Consultant or Advisor would provide. Hence, staff believes section 95923 is needed.

H-1.17. Multiple Comments: Disclosure requirements should be modified or clarified to ensure protection of the attorney-client privilege and duty of confidentiality: clarification is necessary regarding an entity's obligation to provide a description of work performed by a consultant or advisor: An entity registering to participate in the Cap-and-Trade Program must provide detailed information for individuals serving as a Cap-and-Trade Consultant or Advisor. Specifically, an entity employing a Cap-and-Trade Consultant or Advisor must provide, among other things, "a brief description of the work performed ... to the extent disclosure of such a description does not violate any other rules under which the Consultant or Advisor may be required to observe." In the Proposed Regulation Order, "Cap-and-Trade Consultant or Advisor" is broadly defined as "a person or entity that is not an employee of an entity registered in the cap-and-trade, but is paid for information or advice related to the Cap-and-Trade Program specifically for the entity registered in the Cap-and-Trade Program." On its face, a "Cap-and-Trade Consultant or Advisor" would include attorneys retained by entities to provide legal and other advice regarding the Cap-and-Trade Program.

We note that the provision that the disclosure must not violate any rules that the Consultant or Advisor is required to observe is newly proposed language that did not appear in CARB staffs July 2013 Draft Amendments. Presumably, this provision is intended to address stakeholders' concerns that section 95923 would require entities to disclose documents or information protected by the attorney-client privilege. While CARB staff's modified section 95923(b)(2) is an improvement in this regard, it does not specifically exclude disclosure of information that would violate the attorney-client privilege. We believe that such a modification to the Proposed Draft Order is necessary in light of the essential function that the attorney-client privilege serves in the American legal system.

The attorney-client privilege broadly protects confidential communications made between attorneys and their clients, and "has been a hallmark of Anglo-American jurisprudence for almost 400 years." Expressly protected by California statute, the attorney-client privilege is critical to "safeguard[ing] the confidential relationship between clients and their attorneys so as to promote full and open discussion of the facts and tactics surrounding individual legal matters." Indeed, by protecting confidentiality and encouraging open and complete communication between clients and lawyers, the attorney-client privilege ensures that attorneys can provide clients with candid advice and effective representation. The privilege undoubtedly provides an essential legal safeguard that the Regulation should not compromise. Thus, we encourage CARB staff to modify the Draft Regulation Order to make expressly clear that any "description of the work performed" required by section 95923(b)(2) does not include any information protected by or subject to the attorney-client privilege.

Auction advisor disclosure requirements should be modified to safeguard the attorney-client privilege and avoid violation of duty of confidentiality: Section 95914 requires an entity participating in an auction who has "retained the services of an advisor regarding auction bidding strategy" to: (1) inform CARB staff of (a) the identity of the advisor, (b) the advisor's employer, and (c) the advisor's contact information; and (2) provide CARB staff an attestation of the completeness of such disclosure. In addition, however, such an auction advisor must provide CARB staff, in writing, at least 15 days before the auction: 1. Names of the entities participating in the Cap-and-Trade Program that are being advised; 2. Description of advisory services being performed; and 3. Assurance under penalty of perjury that advisor is not transferring to or otherwise sharing information with other auction participants.

Under the Proposed Regulation Order, if an auction participant retained an attorney to advise it regarding some aspect of the auction bidding process, section 95914(c)(3)(D) would require the attorney (not the entity) to provide a description of the advisory services performed for such an entity. In doing so, however, the attorney would violate the attorney-client privilege and the separate duty of confidentiality required by the California Rules of Professional Conduct.

As discussed above, the attorney-client privilege protects confidential communications between clients and lawyers. The right to assert the privilege belongs to the client. However, "the attorney is professionally obligated to claim it on behalf of his client's behalf whenever the opportunity arises unless he has been instructed otherwise by the client." The essential importance of such protection is further evidenced by courts' inability to compel any waiver of the attorney client privilege. Given the significance of the privilege in the American legal system, an attorney who willfully violates the attorney-client privilege may face disqualification from practicing law and incur other sanctions. As written, section 95914(c)(3)(D) would require the attorney, not the client-holder of the privilege, to disclose privileged communications to CARB.

In addition, attorneys are subject to a separate ethical duty of confidentiality, which is even broader than the attorney-client privilege. The duty of confidentiality extends to cover all of the information gained within the scope of the attorney-client professional relationship that the client has requested be kept secret, or the disclosure of which could be harmful or embarrassing to the client. Significantly, a lawyer must "maintain inviolate the confidence, and at every peril to himself or herself to preserve the secrets, of his or her client." While the attorney-client privilege applies in judicial and other proceedings in which an attorney may be called as a witness or otherwise be compelled to produce evidence concerning a client, the duty of confidentiality prevents an attorney from revealing a client's confidential information-even when not confronted with such compulsion. Like the attorney-client privilege, the duty of confidentiality "contributes to the trust that is the hallmark of the client-lawyer relationship," ensuring full and frank communication between client and lawyer, and enabling the lawyer to provide effective counsel to the client. The disclosure requirements contemplated by section 95914(c)(3)(D), however, would require an attorney to violate this duty.

Absent an express exclusion of attorneys from this provision, to avoid running afoul of such disclosure requirements, outside counsel may be forced to refrain from providing any advice to entities regarding the auction bidding process and potentially other related aspects of the Cap-and-Trade Program. As a result, section 95914(c)(3)(D) could have a "chilling effect" on attorneys' ability to advise clients in this regard, which would severely limit the ability of clients to receive complete legal and other advice in such matters. To avoid undermining the attorney-client relationship in this regard, we encourage CARB staff to expressly exclude attorneys from the disclosure requirements in section 95914(c)(3)(D). While CARB staff included this provision "to provide ARB with greater oversight of advisors," we believe such modification to the Regulation will not undermine or affect CARB staff's ability to maintain such regulatory oversight. In light of these considerations, we encourage CARB staff to make every effort to protect the attorney-client privilege and to ensure that attorneys are not required to disclose privileged or client confidential information under the Regulation.

Finally, we note that the auction advisor described in section 95914 would appear to satisfy the definition of "Cap-and-Trade Consultant or Advisor" in section 95923, described above. Thus, for consistency and clarity, it appears that references to "advisor" in section 95914 should be changed to "Cap-and-Trade Consultant or Advisor".

Separately; we request that CARB staff modify or clarify certain disclosure requirements under the Regulation to ensure protection of the attorney-client privilege and to avoid any potential requirement for attorneys to breach their ethical duty of confidentiality to their clients. Absent such modifications, outside attorneys may be forced to refrain from providing any advice to clients in order to avoid the risk of sanctions, or even disbarment.

Recommendation: Exhibit A: Recommended Amendments To Protect Attorney-Client Privilege And Duty of Confidentiality

§ 95914. Auction Participation and Limitations

(c) Non-disclosure of Bidding Information

(3) If an entity participating in an auction has retained the services of an advisor a Cap-and-Trade Consultant or Advisor regarding auction bidding strategy, then:

(C) Any entity that has retained the services of an advisor a Cap-and-Trade Consultant or Advisor must inform ARB of the advisor's retention and identify the advisor, the advisor's employer, the advisor's contact information, and provide an attestation by the Primary Account Representative of the entity retaining the advisor of the completeness of the disclosure; and

(D) The advisor must provide to the Executive Officer in writing at least 15 days prior to an auction, the following information:

1. Names of the entities participating in the Cap-and-Trade Program that are being advised;

2. Description of advisory services being performed without compromising the confidentiality of the attorney-client relationship or any duty of confidentiality afforded by rule, regulation, case law or statute under which the Consultant or Advisor may be required to observe; and (PH 1)

Comment: And, as discussed above, CPEM requests that the ARB clarify that the definition of advisor as used in Section 95914 does not include attorneys subject to regulation under state (and/or provincial) bars that have ethical obligations to protect client confidentiality and are subject to strict conflict of interest rules. (CPM 1)

Response: See response to 45-day comment H-1.11.

In addition, the requirement that Consultants and Advisors disclose information pursuant to section 95914 has been modified in the 15-day changes by deleting formerly proposed section 95914(c)(3)(C), and re-lettering former section 95914(c)(3)(D) as new section 95914(c)(3)(C). This modified section 95914(c)(3)(C) requires only those Cap-and-Trade Consultants or Advisors who are providing advice on auction bidding strategies, not legal matters requiring attorney representation, to disclose the names of the entities participating in the Cap-and-Trade Program being advised, a description of the auction bidding strategy advisory services being performed, and an assurance under penalty of perjury that the advisor is not transferring or sharing that information with other auction participants. Staff notes that if an attorney is acting as an auction bidding strategy advisor, this would constitute non-legal advice and would have to be disclosed. Such disclosure would not impinge upon the attorney-client relationship since auction bidding strategy advice is not legal advice.

H-2. Registration Requirements

CITSS Registration

H-2.1. Comment: Consolidation: PG&E seeks clarification from ARB on the intended purpose of the new language regarding consolidation by facility operators. PG&E also seeks confirmation that the use of the term "entities" is intended, rather than "facilities."

Recommendation: Section 95830(b)(l): An entity must qualify for registration in the Tracking System pursuant to section 95811, 95813, or 95814. If an entity is registering pursuant to section 95811 or 95813, the facility operator identified in section 95101(a)(3) of MRR must register pursuant to this section and meet all applicable requirements of this article. If the facility operators choose to consolidate accounts pursuant to Section 95833, then at least one facility operator of the ~~facilities~~ entities in the direct corporate association must be identified pursuant to this section and meet all applicable requirements of this article for all ~~facilities~~ entities included in the consolidated account. (PGE 2)

Response: The purpose of the new language is to ensure that the operators of the facility with reported emissions register in CITSS, and that they consolidate their facilities under one account, if appropriate. This language already recognizes that registered entities, and actual facility operators, may be different. As such, ARB staff does not believe further changes are needed.

H-2.2. Comment: The added language in section 95830(c)(7) that requires account viewing agents to provide registration details to ARB seems unnecessary and onerous for individuals whose account access is already limited. By definition, an account viewing agent cannot transact, and can only review an account status. The level of detail required for registration in ARB's proposed amendments is not commensurate with an account viewing agent's responsibility.

Consider, also, that it may be common practice for multi-national companies to employ non-US residents as account viewing agents – employees who would not have US bank accounts. (IETA 1)

Response: Staff disagrees that an account viewing agent could access CITSS without registering in the system. All users are required to register in CITSS to gain access, including ARB staff.

By having a US bank account, a registrant has gone through a comprehensive background check conducted by the Federal government as part of the Patriot Act. This lessens the burden on staff to review a registrant's background.

H-2.3. Comment: ARB should include amendments to the cap-and-trade regulations that allow flexibility in CITSS account participation. Currently under the Cap-And-Trade regulations, Primary and Alternative Account Representatives register in CITSS and have the authority to transfer allowances among accounts as a "settlement" function per the definitions of these roles in §§ 95802(9) and (206), along with the registration structure established in § 95832. These CITSS participants are also allowed to participate in the quarterly auctions per § 95912 – in fact, a PAR or AAR CITSS registration is required to participate in these auctions (as well as the APCR auctions, when held).

However, in SMUD, and in many other companies, the “settlement” function is strictly and explicitly separated from the “trading” or auction participation function for transaction integrity reasons. Thus, the broad authority provided to PARs and AARs in CITSS is problematic. SMUD understands that a solution to this problem can be implemented in the CITSS structure when there is time and resources to do so, but that first the Cap- and-Trade regulations must be modified to allow the CITSS solution to be a possibility. Hence, SMUD believes that the Cap-and-Trade regulations should be modified to allow an eventual CITSS solution by providing participating entities the flexibility to designate the proper roles in CITSS for entity personnel. This can be accomplished by simply adding the phrase “… as specified by the entity” to the definitions for PARs and AARs in §§ 95802(12) and (269). These definitions would now read:

> 95802(12) “Alternate Account Representative” means an individual designated pursuant to section 95832 to take actions on an entity’s accounts<u>, as specified by the entity.</u>
>
> 95802(269) “Primary Account Representative” means an individual designated pursuant to section 95832 to take actions on an entity’s accounts<u>, as specified by the entity.</u>

These simple changes are all that SMUD believes is required in the Cap-and-Trade regulations in order to enable auction participants such as SMUD to preserve internal trading guidelines. SMUD believes that this change is within the scope of 15-day changes because § 95802 includes many modifications, including renumbering of the specific subsections for AAR and PAR. In addition, SMUD believes that the change will be useful for a variety of market participants in addition to SMUD, and that the proposed change is noncontroversial and uncomplicated. (SMUD 2)

> **Response:** ARB staff appreciates the commenter’s suggestions, but believes these comments are outside the scope of the proposed regulation since these specific definitions were not amended in the 45-day package. Moreover, the designation of PARs and AARs by an entity implies that these individuals are authorized to act within CITSS on behalf of the designated entity. As such, ARB staff believes the requested changes are unnecessary.

H-2.4. Comment: Change in Ownership: PG&E seeks clarification from ARB on the intent of the changes to Section 95830(i), specifically whether "facility" rather than "entity" is the correct reference. PG&E notes that ARB's "Summary of Proposed Changes" suggests the provision was intended to apply to changes in ownership of covered entities and not facilities, but the proposed regulation next references "when the ownership of a facility changes..." PG&E also suggests the removal of subpart (5), which requires original signatures of the officer or directors of the entity being purchased. PG&E does not see a need for this provision.

95830 (i) Change of ownership due to merger or acquisition. When the ~~ownership of a facility changes~~ registered entity is acquired by or merged into another entity, the following information must be submitted ~~to ARB~~ by the surviving or new entity within 30 days of finalization of ownership change:

~~(5) Original signatures by a Director or Officer from the entities being purchased and the purchasing entity, notifying ARB of the change of ownership.~~ (PGE 2)

Response: ARB staff appreciates the commenter's suggestions. As indicated in subparagraph (i)(1), this provision does include the change in ownership of any entity and the change in ownership of an individual facility. Moreover, the section title – "Change of Ownership" – applies to any reason for the change, not just mergers and acquisitions.

With regard to the removal of subpart (5), staff does not agree with the comment. By requiring a signature from an officer or director of the facility being purchased, staff ensures that both affected parties agree to the change. As such, staff declines to make the suggested changes and deletion.

Broad Information Requirements

H-2.5. Multiple Comments: Overly burdensome requirements that are unnecessary for market monitoring should be deleted: Many of the proposed provisions on market monitoring are overly burdensome and unnecessary for effective market monitoring. The following changes to the Proposed Regulation would ensure effective and efficient market compliance without being overly burdensome or disrupting the market.

Section 95830(c)(1)(I): Registration with ARB: Proposed Section 95830(c)(1)(I) requires disclosure of the name and contact information of all employees that have "access to information on compliance instrument transactions or holdings." The proposed section is vague and overly burdensome because "access" and "information" can be broadly interpreted. SDG&E estimates that more than I 00 SDG&E employees have access to information on compliance instrument transactions or holdings, given the extensive reporting requirements of compliance instrument purchases and holdings to government agencies such as the CPUC and to Sempra Energy, which is SDG&E's parent company. SoCalGas also estimates that more than I 00 employees will have access to information on compliance instrument transactions or holdings, again because of extensive reporting requirements of compliance instrument purchases and holdings to government agencies and to Sempra Energy.

The SDG&E and.SoCalGas employees subject to this proposed requirement work in multiple departments, such as risk management, accounting, regulatory compliance, billing, legal counseling, procurement, and environmental compliance. These employees would include administrative personnel. (SEMPRA 2)

Comment: A number of additional and overly burdensome administrative requirements have been amended in the following sections of the regulation: Updating Registration Information (95830 (f) (1)).

It is unclear to CCEEB how many of these requirements benefit the program and their inclusion presents a significantly increased administrative burden on compliance entities in an already complicated regulation. CCEEB would recommend eliminating these changes, as they do not appear necessary. (CCEEB 1)

> **Response:** ARB staff does not intend to overly burden participants. However, in order to understand relationship networks we are requesting more information about employees who have direct access to compliance instrument transactions or holdings information. This Section's language has been modified in the 15-day changes to more clearly specify which employees should be reported. These include only those employees who have specific knowledge of the entity's market position (i.e., knowledge of both the entity's current and/or expected holdings of compliance instruments <u>and</u> the entity's current and/or expected emissions), which includes future compliance instrument procurement strategy.

H-2.6. Comment: The purpose of Section 95830(c)(1) is to provide separate information on voluntary associated entities (VAEs). This section should therefore be modified to include only employees registered as VAEs who change jobs and have access to aggregate transactions data or holdings information. The employer is aware of all VAEs as a result of new Sections 95814(a)(3) and 95814(a)(4). This data will yield the necessary information to enforce Section 95814(a)(6) without requiring the employer to provide the extensive employee information required under Section 95830(c)(1)(I). Section 95814(a)(6) should also place the burden on the VAEs to report any change in the employment relationship.

> **Recommendation:** SDG&E and SoCalGas request the following modifications: Modification to Section 95830(c)(1)(I) (Registration with ARB):
>
> Names and contact information for all <u>individuals registered as a voluntary associated entities</u> ~~persons who are~~ employed by the entity <u>and whose employment relationship has changed so that they have</u> access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings. (SEMPRA 2)
>
> **Response:** ARB staff disagrees with the assertion that the "purpose of Section 95830(c)(1) is to provide separate information on voluntary associated entities (VAEs)." All entities registering in CITSS must furnish the information required in this subsection, not just VAEs. Subsection 95830(c)(1)(I) allows ARB to track relationship networks between employees of an entity with knowledge of the entity's market position, who may have an incentive to collude.

H-2.7. Comment: Section 95833(a)(2)(F): The Staff's proposed amendment includes a "limited liability corporation" within the meaning of a "direct corporate association," if one entity owns more than 50 percent of the other entity. Shell Energy does not object to including limited liability corporations ("LLC") within the meaning of the disclosure rules. However, it is not enough to establish a "direct corporate association" with an entity by showing that the entity owns more than 50 percent of the LLC. In order to establish the level of "control" that is required for a direct corporate association, the terms of the LLC's operating agreement must be considered. This consideration should be added to the amended language. (SHELL 1)

> **Response:** ARB staff is aware that LLC operating agreements may establish control in a different way than simple ownership. However, ARB staff strives to avoid discretionary qualitative analysis. Thus, a simple quantitative analysis of ownership will be employed to determine whether entities have a direct corporate association. Additionally, the administrative burden associated with evaluating numerous LLC operating agreements would be too high to adequately accomplish the goals of the section. Staff is also not sure who would enforce any internal operating agreement that would prohibit the sharing of market position or auction strategy between the LLC and any board members who are also employees of other registered entities in the Cap-and-Trade Program.

H-2.8. Comment: Information requirements for employees and contractors: In our August 13th comments submitted on CARB's informal discussion draft, WPTF raised concerns about proposed new requirements for entities to provide information on employees or contractors involved with compliance with the cap and trade regulation in sections 95830(c)(1)(i) and (j) and 95923. Although CAR has modified these provisions slightly, we remained concerned that the language is overly broad and would inappropriately require firms to identify employees and contractors that do not play a substantive role in company compliance decisions.

As currently drafted, the regulatory text refers to both to employees involved in "decisions on compliance instrument transactions or holdings" as well as those who have "access to information on compliance instrument transactions or holdings". As WPTF has argued previously, the phrase "access to information" is particularly problematic, as it would cover administrative staff whose access to information may consist of nothing more than printing out documents for a meeting.

CARB's right to apply penalties for failure to comply with any requirement under the regulation means that there is a real financial risk, particularly for large corporations, if an entity fails to fully account for and identify every single employee with knowledge of, access to, or input to information or decisions regarding these issues. Thus, it is critical that the language be specific so that it does not create the potential for significant inadvertent non---compliance.

To address this risk, WPTF urges CARB to revise section 95830(i) to apply only to employees that actually make decisions about holding and transferring compliance instruments. We understand from the explanation given in the Initial Statement of Reasons, that staff is concerned about the possibility of two different registered entities coordinating their actions by actions of individuals participating in the decision making of both entities. To address this concern, CARB should require individual registering in CITSS to submit an attestation that neither the individual nor a member of the individual's family is an employee of any other registered entity under the cap and trade program.

> **Recommendation:** WPTF accordingly suggests the following changes to the language in Sections 95830(i) and (j):
>
> §95830…
>
> (l) Names and contact information for all persons employed by the entity in a capacity giving them access to information on authority to transact compliance instruments transactions or holdings, or access to the entity's Compliance Instrument Tracking System Service account involving them in decisions on compliance instrument transactions or holdings. (WPTF 1)
>
> **Response:** Staff does not intend to overly burden participants. However, in order to understand relationship networks we are requesting more information about employees who have direct access to market position information. The 15-day changes have clarified that these employees include only those employees who have specific knowledge of the entity's market position (i.e., knowledge of both the entity's current and/or expected holdings of compliance instruments <u>and</u> the entity's current and/or expected emissions), which includes future compliance instrument procurement strategy.
>
> .

H-2.9. Multiple Comments: ARB participant registration and information requirements are needlessly broad: An efficient, liquid market facilitates the most cost effective emission reductions. Rules must enable a level playing field between allowance market participants. To this point, entity specific, market sensitive data must be protected to avoid unfairly exposing sensitive position information for compliance entities which could lead to a less competitive market.

ARB requests all possible information with the apparent intent to use it to look for some type of unspecified irregularities. The overwhelming majority of the information gathered will never be useful and represents a waste of resources. Chevron recommends that ARB take a "for cause" or "as needed" approach for anything beyond the current regulatory language. We believe that giving the ARB leeway to ask for additional information when the need arises can accomplish ARB's need to investigate unusual situations without burdening every compliance entity with reporting data that will never be the subject of concern. This type of conditional data request provides the ARB an efficient and effective means to gather data when needed. (CHEVRON 2)

Comment: Finally, we recognize that staff is planning to make changes to reduce or remove administrative burden, and we support those efforts as well. Thank you. (WSPA 3)

Comment: And then lastly, we would like to raise that we are concerned with some of the proposed changes regarding market and administrative burden. But we notice those will be addressed in 15-day changes, so we look forward to working with you. And I seed my 47 seconds. (CHEVRON 3)

> **Response:** Staff appreciates stakeholders' sentiments that the information requirements for CITSS registration are comprehensive. While the requirements are not intended to be burdensome, having such information allows the market monitors to have a better view of market participants and networks. Staff believes the amendments, including those proposed in 15-day changes, strike the appropriate balance between disclosure for rigorous market monitoring and oversight, and ARB and covered entity workload.

CITSS Access Disclosure

H-2.10. Comment: The draft regulation denies an individual's ability to register based on particular circumstances. Given the consequences for breach of the regulations, PG&E believes that it is prudent and reasonable to give an individual or entity the ability to cure an error or omission prior to such registration restrictions.

> **Recommendation:** PG&E proposes the following revision:
>
> Section 95830(c)(8): An individual may be denied registration <u>in each case after the individual has been notified of the failure and given an opportunity to correct the error or omission, as needed.</u> (PGE 2)
>
> **Response:** Staff does not agree that the Regulation should be amended as the commenter suggests because the proposed revision is vague. ARB staff works with stakeholders to try to resolve any issues prior to taking enforcement action. However, the restrictions in place in the Regulation ensure ARB may preserve the integrity of CITSS in cases where it is obvious correction would not be possible.

H-2.11. Comment: Registration: PG&E assumes ARB's intention in requiring tracking system registrations for individuals is to capture those individuals acting on behalf of an entity, such as the primary account representative. In order to act in such capacity, the individuals must have authority from the entity to act, as ARB has made clear in other sections of the Cap-and-Trade Regulations. PG&E has attempted to include language to bridge the gap between individuals and those individuals acting on behalf of registered entities or an entity.

Section 95830(c)(7): Any individual ~~who~~ acting on behalf of and with authorization of a registered entity, which individual requires access to the tracking system, including the primary account representative, alternate account representatives, or account viewing agents must first register as a user in the tracking system.

(c)(7)(D) An individual registering in the tracking system must agree on behalf of the registered entity to the terms and conditions contained in Appendix B of this article. (PGE 2)

Response: Staff disagrees with the comment. The purpose of this regulatory change is to be aware of which employees have knowledge of an entity's market position, not only those with the authorization to change it. This has been further clarified through 15-day changes, which restrict this disclosure to employees who have knowledge of the entity's market position (i.e., knowledge of both the entity's current and/or expected holdings of compliance instruments and the entity's current and/or expected emissions), which includes future compliance instrument procurement strategy.

.

H-2.12. Multiple Comments: Registration with ARB– access to information: Section 95830(c)(1)(I) New Section 95830(c)(1)(I) provides that an entity registering with the ARB must provide names and contact information for "for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings"

CPEM submits that this section is overly broad, unnecessary, and should be eliminated or clarified. As drafted, "all persons with access to information" could cover a substantial number of persons – perhaps the majority of a company's employee pool -- despite the fact that the vast majority of such employees only have access to minor pieces of information, and may not have access to or knowledge of the registrant's account balances, strategies, or other information. By way of example, a records archive administrator or file clerk may have access to a transaction document regarding compliance instruments. A regulatory analyst may be asked to determine whether an early action offset will be subject to revocation. A credit analyst may review a counterparty's credit status for a particular transaction. A computer technician may have access to corporate records, although it would be impermissible for them to use such access. Requiring a registrant to provide names and contact information for employees with just access to such information, without any test of relevancy, is inappropriate. (CPM 1)

Comment: Disclosure of Individuals – Section 95830: BP is concerned with new language in Section 95830(c)(I) requiring reporting of names and contract information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings. This requirement is overly broad, without thresholds or limitations, onerous, unworkable, many times unknowable, and unnecessary in order to address concerns that staff may have.

Our understanding of staff's concerns prompting this new language is that individuals, or family members of individuals, who may be employed by a registered entity are registering as individuals in order to trade for personal gain. We share staff's concern here. That is why BP has a policy that prohibits its employees and their family members from trading products in personal accounts that the company trades or originates as part of its business lines.

As currently drafted this requirement would create significant administrative burden and compliance risk - especially for large corporations where literally hundreds of people could have knowledge of, access to, or input to information or decisions regarding these issues.

A hallway conversation, access to a briefing memo, or participation in an unrelated meeting where these issues were nonetheless discussed are just a few of the ways where the number of employees that fall under this overly broad language would spiral – and knowing or tracking the reporting requirements would be unmanageable by a large corporation. This unmanageability creates compliance risks for large entities.

BP therefore recommends that the Regulation narrow the proposed language to identify employees who have delegated authority to commit the company to purchases and sales of compliance instruments and who have access to the entity's CITSS account. Further, the regulation should require an attestation by individuals who seek to register, that they or their family members are not employees of a registered entity. We believe this, along with the requirement for a letter from the employer for individuals who are employed by a regulated entity should be sufficient. (BP 1)

Comment: Section 95830 adds language that would require entities to provide ARB with contact information for "all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings".

IETA believes this language is overly broad and unnecessary. Within a large company, the list of people who could have access to information could be in the hundreds, and would be very fluid. To maintain a contact list of each of these employees is burdensome and unrealistic. The proposed regulatory language is general, and there is no discernable threshold for access or involvement. How should a situation be treated if a person normally unconnected to the issue offers unsolicited advice in an impromptu discussion?

These registration requirements also pose problems for offset project developers who may work with external entities (consultants, project owners, etc.) to manage projects. For example, within an Ozone Depleting Substance (ODS) destruction project, there could be many technicians who know the number of credits accruing due to the amount of ODS that is being destroyed in the incinerator. Would this constitute knowledge of compliance instrument holdings? Would these technicians need to be listed in the registration? IETA recommends this proposed amendment be struck. (IETA 1)

Comment: Section 95830. ARB should not include burdensome staff reporting requirements: The Joint Utilities oppose the introduction of Section 95830(c)(1)(I), requiring the reporting of names and contact information for all persons employed by a registered entity that either has access to any information regarding compliance instrument transactions or holdings; or is involved in decisions regarding transactions or holding of compliance instruments. This provision is overly broad and unnecessary. It would require entities to track and report hundreds of individuals to ARB for large organizations, including those individuals who may inadvertently obtain information, and update such information within ten days of any changes. Due to the broad scope of individuals covered by Section 95830(c)(1)(I), administration of such a provision would undoubtedly prove burdensome and costly. Further, combined with Proposed Section 95912(d)(5), updates or changes to this information would unreasonably jeopardize an entity's auction participation.

The strict confidentiality requirements already provided for in the Regulation and the security requirements for access to and use of CITSS are sufficient to protect the Cap-and- Trade market from manipulation. The additional information currently required of individuals who register as voluntary associated entities (VAEs) in the amended regulation should prove sufficient to monitor conflicts of interest and the use of information gained on the job for personal benefit. (JUC)

Comment: Overbroad disclosure of employees and contractors: At section 95830(c)(1)(I), ARB has proposed new requirements for entities to provide information on employees or contractors involved with an entity's Program compliance. While it is understandable that ARB would need a record of the individuals that are held responsible for an entity's conduct, the language as proposed could require entities to provide information on any individual with even a minor, non-substantive administrative role in the Program.

The language of section 95830(c)(I)(I), which refers to"...all persons employed by the entity in a capacity *giving them access to information* on compliance instrument transactions or holdings ... " is ambiguous and subject to an interpretation that is overly broad. If read literally, this phrase could be interpreted to apply to employees that would include, for example, accounts payable clerks that process requests for collateral used to post a bid guarantee, or accountants that report the value of the compliance instruments an entity holds in its CITSS account. These administrative duties are often performed by employees that are not involved in any substantive decisions related to the Program. Indeed, sometimes these types of jobs are performed by contract or temporary employees. This amendment to the Regulations would therefore impose significant administrative burdens on companies where various departments and numerous employees are involved in the administrative aspects of the Program.

Presumably, ARB is really concerned with the identity of those individuals developing an entity's compliance instrument procurement strategy, those participating in the quarterly auctions, or those involved in other substantive decision-making for a company registered in the Program.

> **Recommendation:** Thus, SGEN suggests the following revision to the proposed amendment to section 95830(c)(1)(I):
>
> Names and contact information for all persons employed by the entity ~~in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings~~ that are actually involved in decision-making regarding compliance instrument procurement, the transfer of compliance instruments, or the entity's holdings of compliance instruments. (SEMPRA 1)

Comment: The new requirement to provide details about employees with access to cap and trade information should be reconsidered: Proposed new section 95830(c)(1)(I) of the Regulation requires entities seeking to register for accounts to report to the ARB the names and contact information for all employees who will have access to any information on compliance instrument transactions or holdings, or who will be involved in decisions on compliance instrument transactions or holdings.

This type of information is not typically required in other markets, including highly regulated markets such as the electricity market. The ARB should consider whether the benefit it will obtain from this information justifies the burden that this new reporting requirement may impose on covered entities. Given the broad scope of the section, it will cover many employees at each covered entity – upwards of 50 people at larger entities. It will take time to gather and report this information initially, and the information will need to be updated frequently as people are hired, resign, change positions, or assume new responsibilities.

However, if the changes above cannot be made, at a minimum section 95830(c)(1)(I) should be revised to narrow the categories of employees who must be reported. ARB staff members have indicated that their key concern is with employees who must have access to information on compliance instrument transactions or holdings to perform their role, not with employees who merely come across this information from time to time in the course of other duties.

> **Recommendation:** Revisions clarifying this in section 95830(c)(1)(I) are set out below:
>
> (I) Names and contact information for all persons employed by the entity in a capacity that requires~~giving them~~ access to information on compliance instrument transactions or holdings in order to perform their key duties, or who

> <u>make</u>~~involving them in~~ decisions on compliance instrument transactions or holdings.

See also section XIII below on changes to this information prior to an auction or Reserve sale in sections 95912 and 95913. (SCPPA 1)

Comment: The proposed amendments also contain the following new requirement applicable to entities registering with GARB (§95830(c)(1)(1)):

> Names and contact information for all persons employed by the entity that will either have access to any information regarding compliance instruments, transactions, or holdings; or be involved in decisions regarding transactions or holding of compliance instruments; or both.

LADWP believes that GARB's concern that individuals with access to potential market-related data would use that information for personal gain is addressed in proposed §95814(a)(3). The proposed requirements of §95830(c)(1)(1), if broadly applied, would burden covered entities with the task of providing names and contact information of all employees that will have access to compliance instrument information. Larger companies make decisions related to compliance with the cap-and-trade regulation on several levels: staff, work group, and executive levels which involves a significant number of employees. Implementation of the requirement would be time consuming as it would be very difficult to develop the information and keep it updated.

Covered entities registered in GARB's compliance instrument tracking system have already submitted the names and addresses of its directors and officers who would be involved in decisions on compliance instrument transactions or holdings. LADWP believes that this already established mechanism, coupled with the new requirement that an individual registering as a voluntary associated entity be required to provide a notarized letter per §95814(a)(3) would be sufficient deterrent such that a registered individual would not want to use knowledge gained through his/her work as employees of an entity for personal benefit. Thus, LADWP recommends that§ 95830(c)(1)(I) be deleted. (LADWP 1)

Comment: Registration of names of employees (S 95830(c) (1) (I)), (page 65): ARB has proposed the following language:

"Names and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings."

CLFP opposes proposed amendments that would require registering "all persons" employed by the entity with knowledge of the company's activity with allowances and offsets. This casts an extremely wide ARB net without offering any compelling justification as to need or plans for this information.

ARB should explain why the current rules requiring the registration of a Primary Account Representative (PAR) and one or more Alternate Account Representatives (AAR) is insufficient or will not provide ARB with enough contact points to a company. As proposed, the regulation places unwarranted burdens on both companies and ARB, and is a clear example of regulatory over-reach. (CLFP 1)

Comment: ARB should not include burdensome staff reporting requirements: PG&E opposes the introduction of Section 95830(c)(1)(I), requiring the reporting of names and contact information for all persons employed by a registered entity that either has access to any information regarding compliance instruments, transactions, or holdings; or is involved in decisions regarding transactions or holding of compliance instruments. This provision is overly broad and unnecessary. It would require PG&E to track and report hundreds of individuals to ARB, including those individuals who may inadvertently obtain information, and update such information within ten days of any changes. Due to the broad scope of individuals covered by Section 95830(c)(1)(I), administration of such a provision would undoubtedly prove burdensome. Further, combined with Proposed Section 95912(d)(5), updates or changes to this information would unreasonably jeopardize an entity's auction participation. Moreover, it is not clear how such a requirement would contribute to the success of the Cap-and-Trade program or how ARB would analyze, make use of, or benefit from this information.

The strict confidentiality requirements already provided for in the regulation and the security requirements for access and use of CITSS are sufficient to protect the Cap-and- Trade market from manipulation. The additional information required of consultants and individuals who register as VAEs in the amended regulation should prove sufficient to monitor conflict of interest and the use of information gained on the job for personal benefit, an activity already strictly prohibited by PG&E. Additional controls are not needed, would be unduly burdensome for covered entities to prepare, and administratively burdensome for ARB to review, monitor and enforce. As such, PG&E recommends that this requirement be removed. If ARB cannot agree to remove this requirement, the Regulation should narrowly tailor its applicability to those employees who are primary account representatives, alternate account representatives, and account viewing agents. (PGE 2)

Comment: Reporting employees: provisions regarding the disclosure of employees are overly broad and burdensome: The Proposed Amendments should be revised to remove burdensome and unnecessary employee reporting requirements. Section 95830(c)(1) of the Regulation sets forth a list of information that a covered entity must provide in order to register for a CITSS account. The Proposed Amendments would change section 95830(c)(1) to require covered entities to provide additional information, including “names and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings.”

NCPA appreciates the fact that staff has attempted to revise the requested information to reflect the concerns raised by stakeholders in their comments to the June 15, 2013 Discussion Draft. However, as drafted, the Proposed Amendments still seek information on a very broad range of employees, and the ambiguity regarding the scope of an employee's responsibilities as it pertains to the program remain. Employees involved in a capacity "involving them in decisions on compliance instrument transactions or holdings," would likely be a manageable and finite list. The same is not true for compiling a list of "all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings"; this requirement could result in the covered entity disclosing its entire employee roster. Indeed, persons that have access to that information and transactions can change often and without notice. The scope of this requested information remains overly broad. There must be additional parameters around an individual's "access to any information regarding compliance instrument transactions, or holdings," otherwise this could ostensibly include all employees of a covered entity at any given time.

It is also important to note that covered entities have already provided CARB with extensive information on its Primary Account Representatives (PARs), Alternate Account Representatives (AARs), and directors and officers, as that information is already required to be disclosed under the Regulation and for registration with CITSS. Before expanding the covered entities' reporting obligations, there must be a demonstration that the individuals at issue are directly involved in making decisions regarding the acquisition and disposition of compliance instruments. CARB's desire to obtain more disclosure regarding the individuals that are involved in the decision-making process must be balanced and weighed against an additional and potentially burdensome reporting requirement. The reporting should be limited to include only employees that will have access to information regarding trading transactions or similar conduct. The scope of the access and the type of information the employee has access to must be defined in such a way as to address the agency's concerns without being overly broad.

CARB's desire to track the conduct of entities and prevent potential manipulation or malfeasance in the market is laudable. However, as a means to that end, the reporting required under subsection (I) of 95830(c)(1) is overly broad. (NCPA 1)

Comment: Requirements for registration with CARB(§ 95830(c)(1)(i)): CARB is proposing to require that covered entities file a registration application for an account in the compliance allowance tracking system, which would include the "[n]ames and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings." (Emphasis added.) This requirement is overly broad, vague, and unnecessarily intrusive.

Under California law, a regulation is unconstitutionally overbroad or vague if it is not sufficiently definite to provide fair notice of the conduct proscribed or required and fails to provide sufficiently definite standards of application to prevent arbitrary and discriminatory enforcement. The proposed requirement that would require the submission of names and contact information of “all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings” is overly broad. Moreover, it is impermissibly vague. And the scope of this proposed requirement is overreaching and unnecessary in that it would be applicable to every individual in the company that might potentially see such information. Individuals at the lowest level of the company could potentially be pulled in by this regulation, though their access to information regarding compliance instruments is minimal or insignificant. Because this proposed regulatory language is overbroad and vague, it is impossible for regulated entities to know which personnel they must register and which personnel they need not register. Accordingly, the proposed regulatory language will lead to unlawful arbitrary and discriminatory enforcement.

Moreover, the over-expansive scope of the proposed amendment is unnecessarily intrusive in that it would reach far beyond CARB’s function of monitoring the market. CARB’s Compliance Instrument Tracking System Service (CITSS) user registration process requires that persons who “have access to the CITSS” provide certain identifying documentation to their employer to “help ensure the security of the [CITSS.]” This is reasonable given these individuals actually have access to the system. However, it is unnecessary to require the “names and contact information” of individuals whose job responsibilities have no connection to making decisions on holding and/or transferring compliance instruments. The fact that neither Federal Energy Regulatory Commission nor Commodity Futures Trading Commission regulations require such information is indicative of the overreaching and unnecessary scope of proposed Section 95830(c)(1)(I). (APS)

Comment: Section 95830 (c)(1)(I), (J): The Staff Report states that new Section 95830(c)(1)(I), which would require registered entities to disclose the names of all persons employed by the entity in a capacity that would give them knowledge of the entity’s decisions on compliance instrument transactions or holdings, is needed to identify individuals who gain knowledge of a registered entity’s transaction strategy through their work as employees of a registered entity. See Staff Report at pp. 104-05. Similarly, the Staff Report states that Section 95830(c)(1)(J) is needed to disclose the identities of registered entities’ auction bidding advisors or consultants for Cap and Trade activities. The Staff states that the new language would add disclosure requirements for individuals who gain knowledge of a registered entity’s compliance and transaction strategy through their work as consultants. The Staff states that because these individuals may serve as consultants for multiple registered entities, disclosure is needed to enable the ARB to monitor for “collusive activity.” Staff Report at p. 105. The proposed language in these two sections is overbroad and unduly burdensome. In a large corporate organization such as Royal Dutch Shell, this proposed language, if adopted, could require disclosure of numerous individuals that are only tangentially involved in the Cap and Trade program, including individuals in foreign countries. Moreover, the Staff’s failure to provide clear limits regarding the required disclosure would make it difficult to comply. Shell Energy suggests that the ARB withdraw the proposed amendment and replace it with a provision that requires a registered entity to adopt a policy that prohibits its employees (and their family members) from trading products in personal accounts that the company trades or originates as part of its business. Alternatively, Shell Energy recommends that the ARB narrow the proposed language to require disclosure of employees and consultants who have been delegated authority to commit the company to purchases and sales of compliance instruments, and who have access to the entity's CITSS account. The regulation could further require an attestation by any individual who seeks to register, that the individual's family members are not employees of a registered entity. (SHELL 1)

Comment: As currently outlined in Section 95830(c)(1)(I) of the Proposed Regulation Order, ARB seeks to collect names and contact information for "all persons employed by the entity that will have either access to any information regarding compliance instruments, transactions, or holdings; or be involved in decisions regarding transactions or holding or compliance instruments; or both." These requirements are unclear and could present an onerous administrative challenge, particularly for large market participants. Many large covered entities may have hundreds of employees with knowledge of compliance instruments and holdings, most of whom have no role in transaction decision-making. The roles and responsibilities of these employees change frequently, so managing and updating this list would be burdensome, requiring an unnecessarily large and sustained administrative effort.

The ARB's intent in collecting this employee contact information appears to be directed at preventing covered entity employees from registering as Voluntary Associated Entities ("VAEs") with individual tracking accounts, which would create conflicts of interest between market participants. To more effectively prevent such conflicts of interest, the ARB should focus its due diligence on VAEs and consultants hired as market advisors, rather than relying on exhaustive and unwieldy employee data from large compliance entities. (SCE 1)

Comment: Chevron understands that the purpose of this rule is to monitor employees that also act as voluntary associated entities (VAE) so that employees who operate as voluntary participants do not exploit information. Chevron supports efforts to maintain the integrity of the cap and trade market but believes as written this proposed rule could actually work counter to this effort. Chevron has internal governance processes to manage market sensitive information. Chevron suggests that ARB require VAEs to attest if they are employees of regulated entities. Chevron looks forward to working with ARB to identify the appropriate and useful level of participant information to be provided.

Employee Disclosure Requirements: Issue: requiring market participants to disclose all employees involved with the program is difficult to implement and administratively burdensome.

> **Recommendation:** Proposed Change: remove new requirement in Section 95830(c)(1)(I) and, instead, require individuals registering as voluntarily associated entities to attest that they are not employees of a covered entity with access to cap-and-trade information.

Employee Disclosure Requirements:

§ 95830. Registration with ARB.…

(c) Requirements for Registration.

(1) An entity must complete an application to register with ARB for an account in the tracking system that contains the following information: …

~~(I) Names and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings.~~… (CHEVRON 2)

Comment: ARB proposes to impose a burden on covered and voluntary participants to provide contact information for anyone in an organization that has knowledge of or is involved in decisions regarding compliance instrument activity. MSCG does wish to acknowledge that the final proposal was significantly pared back with regard to the degree of information required, from the initially proposed "full" registration, to a much less burdensome "contact list" approach. From the perspective of the physical burden to comply, the improvement is major, and appreciated. Nonetheless, the remaining obligation is, we believe, not commensurate with the benefit provided, and imposes a heavy burden of a different type than the "physical" burden of assembling and submitting the more complex "full registration" documents.

The problem comes from a "recognition" perspective. As written, the number of people in an organization that will be included in the requirement will be very high. In the case of MSCG, our preliminary estimate is that 15-25 people will meet the criteria, and have to be reported to ARB. Most importantly, the burden on the responsible member(s) of management to recognize when additional people meet the criteria and thereby obligate the organization to provide an updated list is extremely difficult to monitor. Just to provide perspective, the functional parts of the organization that will routinely encounter the relevant data include power traders, power schedulers, gas traders, gas schedulers, emissions traders, IT personnel, regulatory personnel, compliance personnel, Legal personnel, accounting personnel, Operations (back office) personnel, administrative assistants and more. Furthermore, in addition to people who will routinely encounter the relevant data, and might reasonably be identified via an exposure analysis, other people will randomly hear about trades and positions in meetings, overhear discussions among, say, accounting colleagues, and even randomly hear about a trade while walking down a row on the trading floor. Identifying the people who routinely encounter trade data will be taxing enough given the scope of people involved; identifying the people who acquire trade data randomly and unbeknownst to the responsible Manager becomes an impossible burden. Add to that the need to constantly remember to supply updates created by personnel turnover, promotion and rotation, and the burden becomes all but impossible.

Hopefully, the description provided above renders new insight into the scope of what is being asked by the new requirement. MSCG strongly suspects that, when this requirement was proposed, the burden of what was being asked was not fully thought through. Regardless, we believe that the burden imposed by the requirement is far beyond being commensurate with the value of the information provided, and strongly recommend that the Board not adopt this Proposed Amendment. Instead, it would be more appropriate to request Staff to re-think the objective and design something better suited to gather necessary information without an unreasonable burden on covered entities.

MSCG argued strongly against the, in our view, excessively burdensome requirements for registration of individuals accessing the tracking systems, particularly with regard to the provision of personal information, when they were originally enacted. We continue to object. In the current Proposed Amendments, ARB intends to extend these extremely burdensome and inappropriate requirements to employees that merely have viewing rights to a system. Whatever the merits of having extensive personal data on individuals who can actually access the tracking system, requiring the same data on individuals that can only view the accounts is exponentially less justified. Furthermore, it puts an additional undue burden on companies such as MSCG which have multinational operations, and may need to have non-US citizens view accounts. Among other issues, such personnel are unlikely to have US bank accounts, one of the major registration requirements. We do not believe that the case has been made for imposing this level of registration requirement on individuals who cannot actually access the tracking system. For that reason, we strongly urge the Board to reject the extension of the “full” registration requirement to Account Viewing Agents, and let the existing requirement stand unchanged. (MS)

> **Response:** ARB staff does not intend to overly burden participants. However, in order to understand relationship networks we are requesting more information about employees who have direct access to compliance instrument transactions or holdings information. This Section’s language has been modified in the 15-day changes to more clearly specify which employees must be disclosed. These include only those employees who have specific knowledge of the entity’s market position (i.e., knowledge of both the entity’s current and/or expected holdings of compliance instruments and the entity’s current and/or expected emissions), which includes future instrument procurement strategy.

H-2.13. Multiple Comments: ARB has proposed language: “Names and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings.”

WSPA opposes proposed amendments that would require registering "all persons" employed by the entity with knowledge of the company's activity with allowances and offsets. This extremely wide ARB net would include those "in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings."

In large companies that are expected to be market participants, including WSPA members, this requirement could include dozens of employees in departments responsible for compliance, accounting, commercial/trading, legal, refining, marketing, strategy and different levels of management. Unfortunately, staff employed in these capacities move to executive and management positions throughout the company routinely. As a result, maintaining an updated registration list would be problematic if not impossible.

WSPA does not understand ARB's need or plans for this information, nor has ARB offered any compelling justification. The registration of a Primary Account Representative (PAR) and one or more Alternate Account Representatives (AAR) should give ARB more than enough contact points to a company. Any more than this is regulatory over-reach and places unwarranted burdens on both companies and ARB.

> **Recommendation:** ARB should eliminate this section and require registration of only those employees designated as PAR, AAR or "Viewing Agents". (WSPA 1)

Comment: The requirement to report complete contact information for any employee who has access to or knowledge of allowance holding or procurement strategy is unreasonable and unenforceable. The proposed rule does not provide sufficient clarity regarding access and information. As written, regulated parties will be compelled to submit excessively large amounts of employee information in order to avoid a potential enforcement risk. Because of the vague nature of this rule the bulk of this information will likely be of no use to ARB and may actually make ARB's tracking and enforcement activities more difficult. (CHEVRON 2)

> **Response:** In response to your comments, we have modified the language in the 15-day changes to read:
>
> > <u>Names and contact information for all persons employed by the entity with knowledge of the entity's market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions).</u> ~~in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings~~

This information will be used to map relationships between entities to prevent collusion and insider trading.

Voluntarily Associated Entities

H-2.14. Comment: Modification to Section 95814(a)(6) (Voluntarily Associated Entities and Other Registered Participants):

> Individuals identified by registered entities pursuant to sections 95830(c)(1)(B),(C),(I), and (J) are not eligible to register as voluntarily associated entities. <u>Individuals with a change in status making them ineligible to register are required to provide notification of the change within 10 working days of the change</u>. (SEMPRA 2)

> **Response:** Ineligible individuals will already be identified pursuant to the registration requirements of 95830(c), rendering the commenter's proposed additional notification of change redundant.

H-2.15. Multiple Comments: SCPPA understands that the ARB's key concern is with employees of covered entities who themselves become voluntarily associated entities under the cap and trade program and may be able to trade using their knowledge of their employer's holdings. However, this concern is already addressed in section 95814(a). Rather than including a broad new reporting requirement for all covered entities, the notarized letter required under section 95814(a)(3) could be expanded to state that the employee in question does not have access to any information about the covered entity's compliance instrument transactions or holdings and is not involved in decisions about compliance instrument transactions or holdings by the covered entity. This would prevent any individuals with such knowledge from opening their own accounts while keeping the new reporting requirements to a minimum.

SCPPA's proposed changes to section 95814(a) are set out below in markup. Section 95830(c)(1)(I) should then be deleted.

> (3) An individual employed by an entity subject to the requirements of MRR, or employed by an entity subject to the Cap-and-Trade Regulation, or by an organization providing consulting services related to those Regulations who chooses to register as a voluntarily associated entity in the tracking system, must provide a notarized letter from the individual's employer stating the employer is aware of the employee's plans to apply as a voluntarily associated entity in the Cap-and-Trade Program, ~~and~~ that the employer has conflict of interest policies and procedures in place which prevent the employee from using information gained in the course of employment as an employee of the company and using it for personal gain in the Cap-and-Trade Program<u>, and that the employee does not have access to any information regarding the employer's compliance instrument transactions or holdings, and is not involved in decisions regarding the employer's compliance instrument transactions or holdings</u>. ...

(6) Individuals identified by registered entities pursuant to sections 95830(c)(1)(B), (C), and (I)~~, and (J)~~ are not eligible to register as voluntarily associated entities (SCPPA 1)

Comment: CARB seeks "information for all persons employed by the entity in a capacity which would give them knowledge of the entity's decisions on compliance instrument transactions or holdings," but the rationale appears to be directly targeted at ensuring that voluntarily associated entities do not game the Program and benefit because of their employment status. This legitimate concern is adequately addressed in the context of the Proposed Amendments to section 95814 regarding Voluntarily Associated Entities, and specifically section 95814(a)(3) and (6). (NCPA 1)

Response: ARB staff disagrees with the commenter that this provision is only applicable to Voluntarily Associated Entities. Rather, this provision is necessary to ensure no individual with access to an entity's compliance instruments or holdings colluding or otherwise engaging in market manipulation. The requirements of 95830(c)(1)(I) have been modified in the 15-day changes to more clearly specify which employees must be disclosed. These include only those employees who have specific knowledge of the entity's market position (i.e., knowledge of both the entity's current and/or expected holdings of compliance instruments and the entity's current and/or expected emissions), which includes future instrument procurement strategy. Staff believes this requirement is necessary to effectively monitor for potential collusion.

H-2.16. Comment: §95814(a)(3) Voluntary Associated Entities (VAE) and other registered participants and §95830(c)(1)(1) registration with ARB: The proposed amendments include a new section (§95814(a)(3)) applicable to an individual employed by an entity subject to requirements of the Mandatory Reporting Rule, or cap-and-trade regulation, or by an organization providing consulting services related to these regulations that chooses to register as a VAE in GARB's trading system. Such individual would be required to provide a notarized letter from the individual's employer stating that the employer is aware of the employee's plans to apply as a VAE and that the employer has conflict of interest policies to prevent the employee from using information for personal gain in the cap-and-trade program. (LADWP 1)

Response: Yes, that is correct.

H-2.17. Comment: Section 95814(a)(3): Voluntarily associated entities and other registered participants: Section 95814(a)(3) should be expanded to include employees of government oversight agencies and interveners in government oversight proceedings with access to carbon market data provided by regulated compliance entities. This change would be in line with the intent of the section as described in the ISOR.

Recommendation: Modification to Section 95814(a)(3) (voluntarily associated entities and other registered participants):

An individual employed by an entity subject to the requirements of MRR, or employed by an entity subject to the Cap-and-Trade Regulation, or by an organization providing consulting services related to those Regulations, <u>or by a government agency with oversight of compliance entities. or by an intervener in government oversight proceedings</u> who chooses to register as a voluntarily associated entity in the tracking system, must provide a notarized letter from the individual's employer stating the employer is aware of the employee's plans to apply as a voluntarily associated entity in the Cap-and-Trade Program and that the employer has conflict of interest policies and procedures in place which prevent the employee from using information gained in the course of employment as an employee of the company <u>or agency</u> and using it for personal gain in the Cap-and- Trade Program. (SEMPRA 2)

Response: Employees of certain government oversight agencies, including ARB, are prohibited from participating in the Cap-and-Trade Program as market participants. Therefore, ARB staff does not believe that the language proposed by the commenter is necessary. However, ARB acknowledges that some government entities are covered entities in the Cap-and-Trade program. Government employees are already subject to mandatory disclosures through the Form 700 filed annually with the Political Practices Commission.

Corporate Association – Disclosure of non-CITSS Entities

H-2.18. Multiple Comments: The Regulation Order requires entities to disclose all corporate associates, regardless of whether they are registered in the cap-and-trade program. Although ARB is characterizing the proposed change as a clarification of an existing requirement, existing Section 95830(c) (1) (H) clearly limits the scope of the disclosure requirement to “entities registered pursuant to this article”. Although the proposed changes may be important to monitor affiliations that may be used in violation of the regulations, the Proposed Regulation Order is simply unworkable and overreaching for large public companies that may have thousands of affiliates in more than 100 countries. Accordingly, Chevron proposes an exemption from this disclosure requirement for publicly traded companies.

Corporate Associations Disclosure: Issue: requiring registrants to disclose all of their affiliated entities regardless of whether they are registered in the program.

Recommendation: Proposed Change: create exemption in Section 95833(a)(1) for publicly traded companies.

Corporate Association Disclosure:

§ 95830. Registration with ARB.…

(c) Requirements for Registration.

(1) An entity must complete an application to register with ARB for an account in the tracking system that contains the following information:

…

(H) Identification of all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833, and a brief description of the association, unless the entity completing an application to register with ARB is a publicly traded company, in which case such entity need only identify such associated entities that are registered in the cap-and-trade program or are registering in the cap-and-trade program. An entity completing an application to register with ARB and for an account in the tracking system must provide all applicable information required by section 95833. (CHEVRON 2)

Comment: Section 95830(c)(1)(H): The Staff's proposed amendment provides that a registered entity must identify every other entity with which the registered entity has a "corporate association," a "direct corporate association," or an "indirect corporate association," as defined in Section 95833(a), whether or not the entity is registered with or intends to register with the ARB. This proposed requirement is unreasonable and unduly burdensome. As Shell Energy noted in its August 2 comments, large multi-national corporations such as Royal Dutch Shell have hundreds, if not thousands, of affiliates that would meet the definition of either a "direct" or an "indirect" corporate association. It would serve no useful purpose for a large corporation to disclose all of these entities, unless the entities intend to register with the ARB. For purposes of compliance with the Cap and Trade Regulations, it should be enough for a registered entity to identify all related entities that are "registered" with the ARB, or registered with a "linked" External Greenhouse Gas Emissions Trading System. Inquiry into a direct or indirect corporate association with an entity that is not so registered is neither appropriate nor necessary. The "Staff Report: Initial Statement of Reasons" ("Staff Report") states that the proposed language requiring disclosure of all "corporate associations," "direct corporate associations" and "indirect corporate associations" "is a clarification [of] an existing requirement and not a new requirement or change in policy." Staff Report at p. 112. Regardless of whether or not this is a "change" to an existing requirement, the proposed language should be stricken. As Shell Energy noted in its August 2 comments, the purpose of the "corporate association" rules is to place purchasing limits and holding limits on entities that are registered with the ARB (or a "linked" Trading System) and that have a "direct corporate association." No reasonable justification exists to disclose an entity's "corporate association" with an entity that is not participating in the Cap and Trade program. The Staff has not provided a reasonable basis for this requirement. This proposed amendment should be stricken or withdrawn. (SHELL 1)

Comment: Disclosure of Corporate Associations – Sections 95830, 95833 and 95912: BP understands the need for CARB to be aware of and track corporate associations for those participating in the state's cap-and-trade program. However, under the proposed changes to the rule, the requirement that a company lists all of its corporate associations, regardless of whether those corporate associations have ever participated in the cap-and- trade program, is onerous and unnecessary to the proper functioning of the program.

BP, as one of the largest and most diverse corporations in the world, has thousands of ever- changing corporate associations across the globe that would fall under the overly broad reach of the proposed regulation. The vast majority of these corporate associations – whether they are a wind farm in Texas, a refinery in Ohio or Australia, or a pipeline in Azerbaijan - are not even remotely related to or impacted by BP's transactions in CARB's cap and trade program. The amendments in the ISOR significantly broaden current and reasonable reporting requirements by removing the language in 95830 (c) (H) which limited reporting to associations with entities registered pursuant to this article and by adding language in 95833 (a) which requires reporting of these associations regardless of whether second entity is subject to the requirements of this article.

Our understanding of staff's concerns that prompted these changes is that apparently some regulated entities are not reporting these associations even under the current, more limited language. Staff are apparently also concerned about associations that may involve entities operating outside of California in linked programs. With regard to the former concern, if entities are not complying because they are uncertain of the requirements, then staff should focus and clarify the requirements – not significantly broaden them. If some entities are willfully not complying, it is appropriate enforcement - and not overly broad regulatory language that unreasonably impacts all regulated entities - that staff should pursue.

The broader requirement (which also relies upon entities to properly report) would put a significant burden on both regulated entities and on CARB staff. Instead of being alerted to associations between entities who are involved in the California cap and trade program, staff would be inundated with tens of thousands of (mostly inconsequential) associations with the burden of then attempting to cross reference these associations in search of a potential violation.

On the issue of linked programs, we suggest that the regulation simply include a requirement to list corporate associations with entities registered in a linked program. (BP 1)

Comment: Section 95830 (c)(1)(h): identification of corporate associations: Section 95830 of the proposed amendments makes a change within the program registration requirements that requires identification of all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association. In the previous regulation, these association disclosures were only required for associated entities registered pursuant to the program. The new proposal significantly expands the requirement for identification to associations far beyond the reach of the California program.

A number of IETA's members are large corporations with many corporate associations across the globe. For some IETA members, the number is in excess of 1000 affiliates and subsidiaries. The requirement as outlined in the amendments would be very difficult to maintain as hundreds of these associations are constantly changing, making submitted lists obsolete soon after submittal to ARB. Given the magnitude of what is being required, IETA wonders if ARB itself would view it as worthwhile to undertake the management of such a large influx of information.

Further, IETA is unsure why it is of interest to ARB to have record of corporate associations for entities not registered or otherwise involved in the cap-and-trade program. Unless there is some rationale that IETA is not aware of, we recommend reverting to the language as written in the current regulation. (IETA 1)

Comment: A number of additional and overly burdensome administrative requirements have been amended in the following sections of the regulation: Registration of names of employees (95830(c)(1) (I));

It is unclear to CCEEB how many of these requirements benefit the program and their inclusion presents a significantly increased administrative burden on compliance entities in an already complicated regulation. CCEEB would recommend eliminating these changes, as they do not appear necessary. (CCEEB 1)

Comment: Expansion of Scope of Corporate Associations: WPTF continues to oppose Staff's proposed changes to Section 95833 that would significantly broaden the umbrella of corporate associations to include affiliated entities "regardless of whether the second entity is subject to the requirements of this article". As we noted in our August comments on the Discussion Draft, many registered entities under the cap and trade program are large corporations with many affiliated companies, and a multi---national presence. In many cases, a regulated entity is a subsidiary of a large corporation, and the subsidiary does not have complete information about all of its corporate associations. This is particularly true of "disclosable" corporate associations (as distinguished from direct corporate associations). Compliance with the existing disclosure requirements under Section 95833 has already proved very challenging and delayed many entities' participation in quarterly auctions. Expanding the definition of corporate associations to include entities that are not subject to the cap and trade program would create additional administrative burden for these companies.

Further, WPTF does not see the benefit of including entities that are subject to neither the California cap and trade program nor linked programs under the umbrella of corporate associations. The proposed changes merely increases administrative costs to entities to comply with the program, and for CARB to implement. WPTF therefore opposes the proposed addition to Section 95833. (WPTF 1)

Comment: Disclosure of Corporate Associations (S95833 (a), pages 74-75)): ARB has proposed new language for corporate associations that requires disclosure where there is >20% ownership of any operation worldwide, regardless of whether it is in

California or has any C&T obligation. In large multinational companies, it is possible that this could involve dozens (or more) of "associations". Extreme examples could include shared ownership of a gas pipeline in Africa, or a marine shipping company for crude oils in Asia.

These challenges also would exist for associations with multiple-partners, joint ventures, or multiple- owners, especially if the entity within the State of California operates independently with its own executive management.

For that reason, WSPA opposes the proposed amendments.

> **Recommendation:** ARB should eliminate the proposed new language that requires identification of associations "regardless of whether the second entity is subject to the requirements of this article" and instead state that the requirement should apply ONLY where the association operates in California, or has a mandatory or voluntary involvement in the California Cap-and-Trade program. (WSPA 1)

Comment: A number of additional and overly burdensome administrative requirements have been amended in the following sections of the regulation: Disclosure of Corporate Associations (95833 (a))

It is unclear to CCEEB how many of these requirements benefit the program and their inclusion presents a significantly increased administrative burden on compliance entities in an already complicated regulation. CCEEB would recommend eliminating these changes, as they do not appear necessary. (CCEEB 1)

Comment: Disclosure of corporate associations (S95833 (a), pages 74-75)): ARB has proposed new language for corporate associations that requires disclosure where there is >20% ownership of any operation worldwide, regardless of whether it is in California or has any Cap-and- Trade obligation. In large companies, it is possible that this could involve dozens (or more) of "associations". Extreme examples could include shared ownership of processing facilities in Asia or India.

These challenges also would exist for associations with multiple-partners, joint ventures, or multiple- owners, especially if the entity within the State of California operates independently with its own executive management.

For that reason, CLFP opposes the proposed amendments. (CLFP 1)

> **Response:** Staff understands the concern that the requirement to identify corporate associates creates an additional administrative burden for entities, specifically multinational corporations. However, staff notes that this is not a new requirement and the disclosure of corporate associations, both registered and unregistered entities, has been a requirement from the beginning of the Cap-and-Trade Program. The changes outlined in the 45 day proposed amendments do

not alter the operative language of section 95833(d)(1) which outlines the information required to be disclosed for associated entities, registered and unregistered. The definitions of direct corporate association in sections 95833(a)(1), (2), and (3) have been modified to explicitly clarify that entities not subject to the Cap-and-Trade Regulation that meet the criteria outlined in section 95833 pertaining to a direct corporate association must be disclosed by a regulated entity. Section 95833(a)(4) outlining the definition of an indirect corporate association has not been altered. The intent of this staggered modification is to minimize, to the extent feasible, the administrative burden of the disclosure by requiring the disclosure of indirect corporate associations only for entities registered in the Cap-and-Trade Program.

Regulated entities have been complying with the requirements of section 95833 disclosing all registered and unregistered direct and indirect corporate associates. Staff has actively monitored this information and entity accounts have been suspended for failure to disclose all direct corporate associates until the account was in compliance with the regulatory requirements. Staff will continue to monitor the relationships between entities and will continue to enforce the requirements of section 95833.

Section 95830(c)(1)(H) was also modified for consistency with 95833. Staff appreciates that the requirements for registration outlined in sections 95830(c)(1)(H) and 95830(c)(1)(I) may require additional clarification and will address the issues in guidance.

The modifications made to section 95833 are intended to provide clarification in the reporting of corporate associates and to lessen the frequency of reporting changes to information pertaining to associates not subject to the Cap-and-Trade Regulation. Section 95833(e)(3) requires that information on corporate associations not subject to the Cap-and-Trade Regulation to be updated quarterly. This change is intended to reduce administrative burden, especially for large multinational entities. Regarding the comment seeking exemption for publicly traded companies, staff notes that such companies already list their subsidiaries on Form 10-K of their SEC filing. As such, they already maintain lists of subsidiaries and associated entities.

Staff understands the commenters' concern of the difficulty in balancing the collection of data required for prudent and expedient market oversight with the administrative burden required in the collection, processing, and updating of information pertaining to corporate associations. Staff believes that identifying direct corporate associations regardless of registration status is vital to properly analyze secondary and related energy markets on the periphery of the primary Cap-and-Trade market. Entities not registered in the program, but operating in related energy or carbon markets, may have undue influence on the market. By identifying relationship between entities across markets and commodities, ARB can better ensure a well-functioning primary market. Therefore, staff declines to make the requested changes which exempt or limit the collection of this necessary information.

Staff will continue to work with stakeholders in guidance to ensure that full market oversight can occur while minimizing the associated administrative burden to the extent feasible.

Corporate Associations – Tracking System Control

H-2.19. Comment: Corporate Associations: The draft regulation's use of "second entity" should be amended to serve a wider audience. For example, it is possible for more than two entities with a 20% interest to be subject to the regulations. PG&E recommends the following changes:

> Section 95833(a)(1)-(3): An entity has a corporate association with another entity, regardless of whether the ~~second~~ <u>other</u> entity is subject to the requirements of this article, if either one of these entities:
>
> > (2) has a "direct corporate association" with another entity, regardless of whether the ~~second~~ <u>other</u> entity is subject to the requirements of this article, if either one of these entities:
> >
> > (3) has a "direct corporate association" with ~~a second~~ <u>another</u> entity, regardless of whether the ~~second~~ <u>other</u> entity is subject to the requirements of this article, if the two entities are connected through a line of more than one direct corporate association.

Section 95833(a)(3)(B): An entity with a "direct corporate association" with another registered entity has a direct corporate association with any registered entity with whom the other registered entity has a direct corporate association. (PGE 2)

> **Response:** ARB staff agrees that it is possible for more than two entities with a 20% interest to be subject to the regulations. However, the corporate association analysis will only be conducted between two entities at a time. The comment may be a semantic dispute about the word "second" versus the word "other." ARB staff believes that the subsection is clear.

H-2.20. Multiple Comments: Clarify section 95833(f)(7) on control of accounts. Proposed new section 95833(f)(7) provides that:

> If a covered entity will have control of the account in the tracking system of another covered entity with which it does not have a direct corporate association, the entities will be considered to have a direct corporate association…

The meaning of the word "control" in this provision should be clarified. Various measures of control are set out in section 95833(a) on criteria for determining corporate associations. However, rather than referring to any of these measures of control, the ISOR states that section 95833(f)(7) relates to “covered entities who share staff for management of their tracking system accounts” because “two covered entities with the same account representatives have the potential to coordinate on market related decisions.” This type of “control” is not defined in section 95833 or elsewhere in the Regulation, and it is not the most obvious meaning of the word “control.”

The Magnolia POUs consider that the statements in the ISOR on this section are reasonable. The drafting of section 95833(f)(7) should be revised to reflect the intended meaning of this section as explained in the ISOR, as the currently-proposed drafting is unclear and does not convey this meaning.

The Magnolia POUs’ proposed changes to section 95833(f)(7) are set out below:

(7) If two~~a~~ covered entities~~y~~ share staff for management of their ~~will have~~ ~~control of the account in the~~ tracking system accounts~~of another covered entity with which it does not have a direct corporate association~~, the entities will be considered to have a direct corporate association… (SCPPA 2)

Comment: Control of an Account: The proposed language at section 95833(f)(7), if read literally, could severely limit and will unreasonably complicate the management and advisory services companies have traditionally provided to participants in existing markets. Proposed section 95833(f)(7) states:

> If a covered entity will have control of the account in the tracking system of another covered entity with which it does not have a direct corporate association, the entities will be considered to have a direct corporate association and the requirements in section 95833(f) apply.

In its Initial Statement of Reasons, staff explained that section 95833(f)(7) was added to "require covered entities who share staff for management of their tracking system accounts to be treated like direct corporate associations with a sharing of the purchase or holding limits," since this may lead to "...the potential to coordinate on market related decisions." While the Cap-and-Trade Program and carbon market are fairly new, the type of energy management services that this proposed language appears to constrain are services that are not uncommon or prohibited in commodity markets generally. Indeed, companies routinely offer and provide services to other market participants which often include management of market positions, providing recommendations on market position valuation, analysis, and strategy, as well as establishing and maintaining various accounts on behalf of a client so the agent can procure and manage Congestion Revenue Rights, bid-in and schedule a client's generation assets in the day-ahead and real-time markets, and buy and sell gas or power. Companies that provide these services implement robust policies, procedures and compliance programs to ensure compliance with, and ensure employees are well educated on, the same conduct that appears to be at the crux of ARB's concern: compliance with antitrust laws, avoidance of conduct that unreasonably restrains competition, conflict of interest, and the obligation to keep any information obtained as part of an advisor-client relationship confidential. The duties performed by one market participant on behalf of another market participant under these arrangements are allowable by market monitors, who are authorized to observe participants' behavior in the market, to ensure that an open and competitive market is maintained and to prevent no one participant from being able to take unfair advantage of the market rules or procedures, to unduly concentrate market power, or to inhibit competition.

If approved, however, the proposed language at section 95833(f)(7) noted above would impose on both entities the requirement to treat each other as if they had a 'direct corporate association' with all of the obligations under the Regulations that this relationship entails, despite the fact that the two entities have only an agent-client relationship and are not, in fact, legally related in any generally accepted corporate entity sense. This is entirely inappropriate, as is the requirement to treat two entirely unrelated legal entities as related for the purposes of sharing purchase and holding limits. Section 95833(f)(7) should be removed from the proposed amendments. (SEMPRA 1)

> **Response:** In response to stakeholder comments, ARB staff has deleted former section 95833(f)(7) as part of the 15-day changes. As such, ARB staff believes the commenters’ concerns have been addressed. ARB staff did include new 15-day language to include a new section 95833(f)(7) related to corporate associations being demonstrated via PARs and AARs with responsibility for developing and executing market activities such as procurement, transfer, and surrender of compliance instruments of another registered entity.

H-2.21. Comment: Section 95833 provides very broad definitions for what is considered by ARB to be an entity's direct or indirect corporate associations. The proposed amendments to that section are apparently intended to make it clear that this disclosure of direct and indirect corporate associations applies regardless of whether the direct or indirect corporate association is subject to the requirements of the Regulations. Under section 95833(e)(3), a registered entity is required to disclose within 30 days any change of information regarding its direct and indirect corporate associations.

It is also unclear why ARB would need, or even want, to have this information in 10 days (versus 30 days) regarding corporate entities that are not registered, not subject to the Regulations and are not even located within California in many cases. For example, what possible reason could ARB have in needing information regarding a change in SGEN's "corporate associations" in Peru or Indiana within a ten day period versus a 30 day period? Because of the administrative burden of updating information regarding direct and indirect corporate associations not subject to the Regulations, the 30 day rule should be maintained for this sort of information update. (SEMPRA 1)

> **Response:** In response to stakeholder comments, ARB staff modified section 95833(e)(3) in the 15-day changes to provide additional time for entities to

disclose information and made the reference to corporation associations more specific (i.e., at least quarterly).

H-2.22. Comment: The proposed language in Section 95833(f)(6) unnecessarily constrains an entity's ability to update information regarding corporate associations. This proposal fails to recognize the sophisticated corporate structures of many of the entities regulated under the Cap-and-Trade program. These structures are unlikely to remain stagnant over the course of a year and as such, these entities should be permitted to engage in normal business activities without limitations imposed by this Section. Given that ARB holds quarterly auctions and an entity must submit an application, which includes information regarding corporate association, to participate, entities should be permitted to change their corporate association accounts including whether or not to consolidate at this time.

Recommendation: PG&E recommends the following change to Section 95833(f)(6):

Entities with a direct corporate association may change their decision to consolidate accounts or opt-out of consolidation provided the entity reports such changes at least 30 days prior to an auction in accordance with Section 95912(d)(2) ~~only once each compliance period.~~ (PGE 2)

Response: Direct corporate associates are required to either opt-out of consolidation, or consolidate their accounts and share position limits. While the corporate association may not remain stagnant, this Section restricts how often account types may be changed to ease in implementation of the program. As such, staff declines to make the suggested changes.

Know Your Customer Information

H-2.23. Comment: The cap-and-trade regulations should be modified to explicitly include option 2 as a viable method of meeting the know your customer requirements: As the ARB began implementation of the Cap-and-Trade Program last summer, the Know Your Customer requirements raised significant concerns among covered entities. ARB responded at that time with guidance providing a second option for meeting the KYC requirements, involving much of the sensitive information being held by the covered entities themselves, and available for ARB inspection as required. The CITSS User Guide, Volume 1 describes these options and provides for compliance documentation with a covered entity attestation form (where the covered entity holds the KYC information in-house and files an attestation that it has the required information) or an individual attestation form (where the documentation would be sent to ARB for each individual).

SMUD appreciated the guidance provided at that time and understands that this guidance continues to be in place. Nevertheless, SMUD was under the impression that eventually changes would be made to the Cap-and-Trade regulations to clarify that the compliance entity attestation option was an explicit choice for the KYC requirements.

> **Recommendation:** SMUD urges the ARB to modify the language in the Proposed Regulation Order to address this issue as follows:
>
> Section 95834 (b): The individual must provide, either directly or by covered entity attestation, documentation of the following: …. (SMUD 2)
>
> **Response:** ARB did not propose changes to section 95834(b) and is continuing to evaluate the need for such an amendment. It is also considering these applications on a case-by-case basis while the evaluation of the need for such a change is ongoing.

H-2.24. Multiple Comments: WPTF understands that the intent of the know-your-customer requirements is to enable verification of the identity of individuals registered in CITSS. CARB does not have a valid interest in the information required (i.e. bank account, address, photo identification) except to the extent that it helps to establish the identity of the individual registering. Once the individual's identify has been verified, there should be no need for resubmittal of this information, since an individual's identity will rarely change. In the event that an individual's identity does change, then provisions for changing account representatives under section 95832(f) would apply.

Thus, WPTF sees absolutely no need for resubmittal of the know-your-customer documentation. The Know-Your-Customer provisions and documentation requirements are already burdensome and far beyond those required under the European Emission Trading Program. To require further that individuals must re-submit information every two years is excessive and unnecessary. We urge CARB to delete. (WPTF 1)

Comment: Section 95834(c)(2) adds a requirement that individuals registered in CITSS re-submit registration information every two years to enable the re-verification of documentation.

IETA appreciates the importance of adequate Know-Your-Customer requirements (KYC) for registration in the program, but questions the need for ARB to require that individuals re-submit this information every two years. The KYC requirements are already burdensome; a biannual re- submittal of that information (i.e. bank account information, addresses, photo identification) seems unnecessary and onerous. IETA recommends striking this proposed amendment, and retaining the language that ARB already has in place that would require re-submittal of information in the event that an individual's identity changes. (IETA 1)

Comment: Resubmittal of Know-Your-Customer documentation: WPTF is also extremely concerned about staff's proposed addition to Section 95834(c)(2) requiring individual's registered in the CITSS to re-submit registration information every two years to enable re-verification of this documentation. (WPTF 1)

Comment: "Know-Your Customer" Requirements (S95834): ARB has proposed changes to 95834 (Know Your Customer Requirements) by allowing the Executive Officer to re-verify information listed in Section 95834 (b) every two years for individuals registered as primary account representative, alternate account representative or account viewing agent. This list of information is extensive and includes private confidential information such as a documentation showing bank accounts in the United States. At the start of the program, ARB staff insisted that a copy of a bank statement was required, but subsequently accepted a letter from a bank or from an employer stating the company automatically deposits payroll payment to the employee's bank account in the United States.

Recommendation: Amend Section 95834 (b) to clearly indicate the type of documents that can be used to demonstrate an open bank account in the United States. (WSPA 1)

Comment: Revise the KYC re-verification provision to allow entities to specify information that has not changed: Proposed new section 95834(c)(2) provides that the Executive Officer may re-verify all documents required pursuant to the Know-Your-Customer ("KYC") requirements in section 95834 every two years, and that upon request individuals must provide updated documentation.

The KYC requirements are extensive and require individuals to provide a considerable amount of information to the ARB. It would be very burdensome if full re-verification was required every two years. Rather than providing additional notarized copies of documents, individuals should be given the option to attest that there have been no changes to their information. Individuals should only be required to provide documents again if the relevant piece of information has changed since the previous submission.

> **Recommendation:** SCPPA's proposed changes to section 95834(c)(2) are set out below:
>
> (2) The Executive Officer may re-verify all documents required pursuant to Section 95834 every two years. To allow verification, upon request, the individual must provide updated documentation required pursuant to section 95834(b), or an attestation that the documentation remains unchanged since it was previously submitted pursuant to section 95834. (SCPPA 1)
>
> **Response:** The know-your-customer information updates as described in the regulation are necessary for the effective monitoring of CITSS users. It is unlikely that all users would provide updated information if they were not requested to do so. Staff believes that resubmittal of information, upon request, every two years is not overly burdensome.
>
> Staff believes that including specific types of documentation to demonstrate an open bank account in the United States under section 95834(b) could conflict

with existing methods that financial institutions adopt for demonstrating open bank accounts. As such, this provision remains unchanged.

Timing of Information Updates

H-2.25. Multiple comments: Inconsistent and burdensome timing requirements: There is an inconsistency between the timing requirements for updating information pursuant to section 95830(f)(1) and section 95833(e)(3), which became apparent when reviewing the proposed amendments to section 95830(c)(1)(H) and section 95833.

Pursuant to section 95830(c)(1), an entity registering for an account in the tracking system must provide certain information to ARB including, among other things: "Identification of all other entities registered pursuant to this article with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 ..." Section 95830(c)(1)(H). Further, under section 95830(f)(1), both the existing regulation and in the proposed amendment, an entity is required to inform ARB within 10 working days if there are any changes to the information provided as part of the registration process under section 95830(c).

The proposed amendment to remove the reference to "registered pursuant to this article" in section 95830(c)(1)(H) would therefore create an irreconcilable inconsistency between section 95830(f)(1), which requires any changes to the information registrants submitted pursuant to section 95830(c) to be updated within 10 working days, and section 95833(e)(3), which requires entities to inform ARB of changes in information concerning all direct and indirect corporate associations within 30 days. In addition, this inconsistency renders both regulations confusing and the 30 day rule in 95833(e)(3) potentially superfluous.

Changes in information regarding corporate associations not themselves registered should be subject to the 30 day rule of section 95833(e)(3) and not the 10 working day rule in section 95830(f)(1). A requirement to provide information regarding any change concerning all direct and indirect corporate associations (not just those corporate associations which are also registered in the Program) within 10 working days of a change would be unduly burdensome and without a corresponding purpose with respect to the Cap-and-Trade program. Many registered entities, such as SGEN, do not have immediate access to information regarding corporate associations that have nothing to do with the registered entity's business and may even be located in other states or countries. Requiring entities to report all changes to their direct and indirect corporate associations not subject to the Regulations within 10 working days is unworkable as a practical matter, and puts registered entities at a constant risk of non- compliance. ARB should be cognizant of the business reality that many large corporate structures involve dozens (even hundreds) of affiliates and subsidiaries which operate largely independently from one another, and hence one entity may not have readily available access to information regarding the others with whom the only relationship they share is that of having the same ultimate corporate parent.

If section 95830(c)(1)(H) is not amended as proposed and "registered pursuant to this article" remains in the text (as it is now), section 95830(f)(1) could reasonably be interpreted to apply the 10 day rule to only those corporate associations that are themselves registered and subject to the Regulations, while changes in information regarding corporate associations that are not registered are required to be submitted to ARB within 30 days of a change pursuant to section 95833(e)(3) as is currently done. Leaving in place the phrase "registered pursuant to this article" would also make the additional amendments to section 95833, which add in numerous places the phrase "regardless of whether the second entity is subject to the requirements of this article" make more sense. Therefore, "registered pursuant to this article" should not be deleted from section 95830(c)(1)(H).

Should staff move forward with recommending the proposed change to section 95830(c)(1)(H), however, SGEN requests that ARB reconcile the code sections by adding appropriate language to make clear that registered entities are required to report information as to direct and indirect corporate associations within 30 days of a change as stated in section 95833(e)(3), not within 10 working days. (SEMPRA 1)

Comment: Moreover, without at least some test for materiality, requiring a registrant to keep such a list up to date within 10 working days of any change, as required by the Section 95830(f)(1), is extremely burdensome, as an employee may on occasion perform a function providing access to information – even non-material information – that could trigger the very broad rule accidentally. Consider, for example, a maintenance person temporarily re-assigned for one week for vacation coverage to internal mail delivery/copy room functions. Would a registered entity be required to submit a regulatory filing within 10 days of that event? CPEM does not believe that other regulators – the CFTC, FERC, the SEC, or similar bodies, require this type of information for compliance, and do not believe it is necessary or appropriate here. (CPM 1)

Comment: To make matters worse, the regulation includes a requirement that registrants update registration information within 10 working days of any change. This would mean that BP would be required to notify CARB within 10 days of a change within any one of thousands of corporate association around the globe. We are simply not set up as a corporation to provide internal let alone external notification of such changes within this sort of timeframe. Ten days notification is a reasonable requirement when the reporting of associations is limited to entities registered in the California program – or within linked programs. It is a wholly unreasonable requirement when it applies to thousands of associations around the globe with no relationship to the California program. (BP 1)

Comment: Section 95830(f)(1) requires updates to the name and contact information of all employees disclosed under Section 95830(c)(1)(I) within 10 working days of a change. Submitting updates on changes in the many different departments at SDG&E and SoCalGas every 10 working days would be extremely burdensome and not useful for market monitoring. (SEMPRA 2)

Comment: Section 95830(f)(l): Timing of registration updates: The proposed modifications to Sections 95930(c)(l)(H) and 95833 require that covered entities disclose changes in corporate associations regardless of whether the associated entities participate in the cap-and-trade program. For large entities like Sempra Energy, which is the parent company of SDG&E and SoCalGas, the hundreds of subsidiaries are constantly changing. The requirement in Section 95830(f)(l) that covered entities update ARB within 10 working days of any changes to associated entities, including entities that do not participate in the cap- and-trade program and entities outside the United States that cannot participate in the cap-and- trade program, is overly burdensome and unnecessary for effective market compliance. Section 95833(e)(4) already requires disclosure of any changes to associated entities by the registration deadline for each auction. Thirty day is also referenced in this section as the disclosure time frame, and it is unclear which time frame applies.

In addition, Section 95830(f)(1) requires updates to registration information within 10 working days of any change to registration information. This timing requirement is overly burdensome given the provisions in Section 95830(c) requiring disclosure of all changes in corporate associations and all changes in employee positions with any knowledge of the entity's transactions or holdings. ARB should modify the Proposed Regulation to change the deadline for updates listed in Section 95830(c) to the deadline for the auction participation application. For consistency, Section 95833(e)(3) should be deleted as well.

> **Recommendation:** Modification to Section 95830(f)(1) (Registration with ARB):
>
> > Registrants must update their registration information as required by any change to the provisions of 95830(c) <u>no later than the auction registration deadline established in Section 95912.</u> ~~within 30 days of the changes becoming effective. When there is a change to the information registrants have submitted pursuant to 95830(c), registrants must update the registration information within 10 working days of the change.~~
>
> Modification to Section 95833(e) (Disclosure of Corporate Associations)
>
> > ~~Within 30 days of a change to the information disclosed on corporate, direct, and indirect corporate associations; and~~ (SEMPRA 2)

Comment: Updating Registration Information (S95830 (f) (1), page 68): ARB has proposed new registration requirements: Any “changes” in information must be submitted to ARB within 10 days, and any newly required information must be provided within 30 days of rule adoption.

WSPA recognizes that ARB must be made aware when details of company registrations change. However, as the registration requirements grow in complexity, it is incumbent upon ARB to grant more time for changes to be fully implemented throughout the company up to and including registration on file with ARB. It is therefore unreasonable to continue to request that all updates to information be provided to ARB within 10 days. Further, it is unreasonable to expect that information required by new amendments be provided to ARB within 30 days.

> **Recommendation:** ARB should revise both of these requirements to provide that a company would need to notify ARB within 60 days. (WSPA 1)

Comment: BP strongly recommends that the proposed language removed from 95830 (c) (H) (registered pursuant to this article) be restored and that the added language in section 95833 (a) which requires reporting of these associations regardless of whether second entity is subject to the requirements of this article – be removed - with the result being that reporting of associations is only required when those associated entities are participating in the California cap and trade program and/or a program linked with the California program. If necessary, the regulation should seek to clarify these requirements rather than broaden them. Making these recommended changes will make the requirement manageable for the large corporate entities who would be most affected by this change. With these recommended changes, the required 10 day notification of changes in corporate associations, as well as the potential denial of auction participation for changes in these associations in proximity to an auction, also become more manageable. As previously stated, we suggest that the regulation include a requirement to report associations with entities registered in linked programs. These changes will also make clearer where and when a potential willful violation has occurred – and proper enforcement actions that deter future violations can occur. Without these suggested changes, it is virtually certain that there will be hundreds or thousands of instances of inadvertent and inconsequential violations – with staff having to sift through these violations to determine which had an impact on the program and/or warrant enforcement. We believe it is clear that without these recommended changes, the regulation will be needlessly burdensome and problematic for both staff and regulated entities and will cause unintended consequences for regulated entities who are attempting to act in good faith. (BP 1)

Comment: Updating registration information (S95830 (f) (1), (page 68): ARB has proposed new registration requiring that any “changes” in information must be submitted to the ARB within 10 days, and any newly required information must be provided within 30 days of rule adoption.

CLFP recognizes that ARB should be informed when details of company registrations change. However, as the registration requirements grow in complexity, it is incumbent upon ARB to grant more time for changes to be fully implemented throughout the company up to and including registration on file with ARB. It is unreasonable to continue to request that all updates to information be provided to ARB within 10 days. Further, it is unreasonable to expect that information required by new amendments be provided to ARB within 30 days.

CLFP recommends that ARB revise both of these requirements to provide for notification to ARB within 60 days. (CLFP 1)

> **Response:** Staff agrees with the commenters that there was an inconsistency in the timing requirements released in the 45-day amendments. That inconsistency has been resolved in the 15-day changes. The proposed changes now require updates within 30 days or quarterly of a change, depending on the information. This change provides participants with sufficient time to update relevant information. With regard to the comment about the burden of reporting affiliates and subsidiaries, listed companies already publish these lists with their SEC 10-K filing. Thus, there is no need to recompile the lists and the requirement is not burdensome. See also response to 45-day comments H-2.18 *Corporate Association – Disclosure of non-CITSS Entities* regarding the rationale and necessity of reporting corporate associations.

H-2.26. Comment: In multiple places, the regulation inconsistently refers to both 'calendar days' and 'working days' in setting deadlines for entity registration requirements. For instance, section 95830(d) sets a registration deadline of 30 calendar days of the date the regulation becomes effective for an entity. In contrast, section 95830(f)(1) refers to simply 'days' and 'working days'. Given the potential financial penalties to an entity for violation of these deadlines, we urge CARB to review and revise the regulation so that all deadlines refer to 'working days.' (WPTF 1)

> **Response:** Thank you for the comment, the inconsistent use of "days" has been corrected between these sections.

H-2.27. Comment: Inconsistent Use of "Days": Throughout the Regulations, the due date for various reporting obligations and other timing requirements are sometimes stated in terms of "business days," "working days," "calendar days," or just plain "days," and sometimes more than one of these terms is used within the same section of the Regulations. ARB should take this opportunity to amend any sections of the Cap-and-Trade Regulations that refer to timing in order to ameliorate any confusion, and consistently state the number of days in which an action is intended to be taken. (SEMPRA 1)

> **Response:** Staff disagrees that all deadlines should refer to working days. Some deadlines are appropriate on a calendar day basis, while others are more appropriate for working days. If a requirement states "working" or "business" days, covered entities must follow that requirement; if a requirement states "calendar days," that requirement must be followed. That said, staff has modified various sections in 15-day changes to reduce the number of times different types of "days" are used.

H-2.28. Comment: Clarify the timeframes in section 95830(f)(1) apply to the date the update was submitted: Proposed new section 95830(f)(1) provides that registrants must update their registration information within 30 days of a change to the Regulation and within 10 working days of a change to the information. For some types of registration information, registrants can update their information directly; in other cases, registrants must submit the updated information to the ARB and the ARB then processes the change. In the latter case, it may take some time for the change to the information to be recorded. This processing time should not count towards the 30- or 10- day deadline.

Therefore, section 95830(f)(1) should be revised to clarify that the deadlines to update information apply to the date the new information was submitted, not the date the change was actually recorded on the relevant platform. Additional clarity regarding the different meanings of the word “change” in the first and second sentence of this section would also be welcome.

> **Recommendation:** SCPPA’s proposed changes to section 95830(f)(1) are set out below:
>
> (1) Registrants must submit updates to their registration information as required by any change to the provisions of 95830(c) within 30 days of the changes to those provisions becoming effective. When there is a change to the information registrants have submitted pursuant to 95830(c), registrants must submit updates to the registration information within 10 working days of the change to the registration information. (SCPPA 1)
>
> **Response:** ARB staff disagrees with the comment and believes the subsection is clear.

H-2.29. Multiple Comments: Section 95912(d)(5): Auction Administration and Participation Application: Section 95912(d)(5) should be narrowed. As written, it is overly broad and extremely burdensome. The section appears to preclude SDG&E and SoCalGas from allowing hundreds of employees, including officers, to change jobs roughly six months (45 days for four auctions = 6 months) and could preclude SDG&E and SoCalGas from auction participation for circumstances outside the companies' control. For example, SDG&E or SoCalGas could be precluded under the proposed regulation if any of the following occurred: (1) employees or officers leave the entity, (2) Sempra Energy acquires or sells a subsidiary, or (3) the State of California assigns a new business number.

This provision could also disrupt the auction if a change were to occur after the auction results were released and then a participant was precluded from participation. Section 95912(d)(5) should be narrowed to avoid these problems and to be more consistent with the rationale in the ISOR for processing applications. As long as the information in an auction application is accurate at the time of its submittal, an entity should be allowed to participate in the auction unless it changes as an entity. ARB would still have Section 95914(a) as proposed to use for enforcement if information in Section 95830 was false or misleading in a material way.

> **Recommendation:** Modification to Section 95912(d)(5) (auction administration and participation application)

> An entity with any undisclosed changes to the auction application information listed in subsection 95912(d)(4)(A) ~~or account application information listed in section 95830~~ within 30 days prior to an auction, or ~~an entity whose auction application information or account application information listed in section 95830 will change within 15 days~~ after an auction but prior to public disclosure of auction results, may be denied participation in the auction. (SEMPRA 2)

Comment: New proposed language in Section 95912(d)(5) would exacerbate the problem. Under this section, if the aforementioned list changes 30 days prior to an auction or 15 days after an auction, the entity's auction participation may be denied. (SCE 1)

Comment: "Known" Changes to an Auction Application: The proposed amendments would add section 95912(d)(5) providing that auction participation may be denied if an entity "has any changes to the auction application information listed in subsection 95912(d)(4), or account application information listed in section 95830 within 30 days prior to an auction, or an entity whose auction application information listed in section 95830 will change within 15 days after an auction."

The addition of this section appears to be aimed at preventing entities from participating in auctions when that entity is aware of a considerable change that may occur soon before or after the auction. Given the complexities that exist in large corporations, as previously noted, program participants may not be aware if, within the panoply of affiliates, an entity is created within 15 days after an auction, or if the creation or dissolution of an entity is even contemplated.

> **Recommendation:** Thus, SGEN suggests section 95912(d)(5) be removed from the proposed amendments. Should staff continue to recommend the proposed amendment, however, ARB should revise it as follows:
>
> An entity that is aware of changes to the auction application information listed in subsection 95912(d)(4) or account application information listed in 95830 within 30 days prior to an auction, or an entity whose auction information listed in section 95830 will change within 15 days after an auction, must report those changes to ARB within 30 business days of being notified on the change(s), or the entity may be denied participation in the auction. (SEMPRA 1)

Comment: Section 95912. ARB should not unreasonably restrict an entity's auction participation: The Joint Utilities oppose Section 95912(d)(5) of the proposed amendments, which may bar an entity from participating in an auction if there are changes to information provided in an entity's auction or account application 30 days before or 15 days after an auction. This proposal is unduly restrictive and should be removed or significantly modified. The activities described in the auction or account application cover a range of activities that a company may need to perform in the course of its business and simply cannot remain static for 180 days a year in order to participate in the Cap-and-Trade program.

For example, an entity may need to raise capital to finance its activities, impacting information provided in its auction application. Proposed Section 95912(d)(5) jeopardizes an entity's ability to participate in ARB auctions because of such an activity. Combined with the proposed revisions to section 95830, Section 95912(d)(5) unreasonably threatens an entity's auction participation based on changes to the list of employees, without regard for whether or not the change is within the control of the registered entity. This restriction is unnecessarily burdensome, and particularly so for large compliance entities with many employees working on Cap-and- Trade Program issues. It is unreasonable to assume an entity can prevent employee job functions from changing within each of these 45-day periods, or restrict employees from leaving and/or changing jobs.

While ARB staff has stated that Section 95912(d)(5) is intended to facilitate effective settlement of the auctions and support market monitoring, and is not intended to be overly burdensome, Section 95912(d)(5) should be rejected because it unnecessarily jeopardizes an entity's auction participation for activities associated with its normal business operations. (JUC)

Comment: Constraints on auction participation: the regulation should not place unreasonable constraints on an entity's ability to participate in the auction based on changes 30 days prior to and 15 days after the auction.

The Regulation must balance CARB's interest in monitoring the market and overseeing the conduct of covered entities with those same entities' need to operate their core businesses and comply with the Regulation. Section 95912(d)(5) of the Proposed Amendments should be removed or significantly modified in order to avoid substantial disruptions to basic business operations. Under the Proposed Amendments, entities with "any changes to the auction application information listed in subsection 95912(d)(4) or account application information listed in section 95830 within 30 days prior to an auction , or an entity whose auction application information or account application information listed in section 95830 will change within 15 days after an auction, may be denied participation in the auction." Even without a closer look at the detailed list of information that is implicated under sections 95912(d)(4) and 95830, any restrictions on corporate changes that would impede regular business transactions for 45 days, four times a year is unreasonable. The Proposed Amendments can implicate matters such as a PAR or ARR leaving the company, or a call to raise capital. NCPA understands that staff is primarily concerned with corporate changes that could impact auction settlements or provide other entities a competitive advantage in the auction. However, the breadth of the proposed restriction goes far beyond addressing that specific concern. Instead, the requirement would endanger normal business transactions, and indeed, could be implicated even in instances where the registered entity has no control over the changes. The Proposed Amendments already address the need for "notification" of changes in section 95830(f). Accordingly, NCPA urges the Board to direct staff to remove this provision. In the event that similar restrictions are deemed essential to the Program, section 95912(d) should be revised as set forth below, and also identify the core information and/or circumstances that CARB is seeking to prohibit.

> An entity with any changes to the auction application information listed in subsection 95912(d)(4) or account application information listed in section 95830 within 30 days prior to an auction, or an entity whose auction application information or account application information listed in section 95830 ~~will~~ changed ~~within~~15 days after an auction shall update the information listed in 95912(d)(4) within 10 working days of such change. ~~may be denied participation in the auction.~~ (NCPA 1)

Comment: Changes in auction application information: The Proposed Amendments would allow CARB to deny participation in the auction to any entity if certain information in its auction application or accounts application should change within the 30 days before or 15 days after an auction. The proposal is unworkable with respect to changes occurring after the auction because it is unclear how CARB could enforce it without impairing the integrity of the certified auction results. Even if a change should occur before the auction, the proposal sweeps too broadly and could bar participation due to changes only affecting distantly related companies having nothing to do with the Cap-and-Trade program or inconsequential personnel changes. CARB should rethink this proposal and at the very least limit it to changes occurring within the 30 days prior to an auction that pertain to the entity itself or its direct corporate associations and may affect computation of the purchase limit or holding limit.

The proposal to bar an entity from the auction due to changes in its auction application information is unworkable: Section 95912(d)(4) of the Regulation currently requires every auction participant to complete an auction participation application at least 30 days prior to each auction. The Proposed Amendments would expand the list of information that must be provided under section 95912(d)(4) and add a new provision whereby "[a]n entity with any changes to the auction application information listed in subsection 95912(d)(4)…within 30 days prior to an auction, or an entity whose auction application information…will change 15 days after an auction, may be denied participation in the auction."

Notably, CARB revised this provision slightly from what appeared in the July discussion draft, which stated that an entity whose auction application information changes "*will* be denied participation in the auction". In contrast, the Proposed Amendments provide that an entity experiencing such changes "*may* be denied participation…", suggesting that CARB intends to exercise discretion in deciding whether any particular change warrants disqualification from the auction. When a stakeholder at the July 18, 2013 CARB workshop regarding the discussion draft raised the issue of how an entity would comply with this new requirement in a scenario where the change in the application information occurs *after* the auction, CARB staff provided a response to the effect that an applicant would only be denied participation if the change in status were foreseeable, although neither the discussion draft, nor the Proposed Amendments, limits the changes that may trigger disqualification to only those that are foreseeable. This response underscores the broad discretion that CARB will likely wield in enforcing this provision and, correspondingly, the great uncertainty registrants will face, as they wrestle with difficult questions of whether changes that might or might not occur within the 15 days following an auction (many of which they have no control over) will bar them from participation in the forthcoming auction.

It would be unworkable for CARB to bar entities from participation for changes that occur after an auction has already occurred. Excluding the disqualified participant's bids after the auction has already been conducted and the results have already been certified by the auction administrator could result in changes in the reported settlement price and auction results. Such changes should not be countenanced, as they would seriously undermine the certainty associated with the certified auction results and the market signals they are intended to provide. In the event that a participant is not disqualified until after financial settlement has occurred, the change in settlement price could impact all parties to the auction, not just the participant who is disqualified, and the Regulation does not currently provide for such a post-settlement refund.

Even if a change should occur within the 30 days before an auction, it would be unworkable for CARB to bar participation based on many of the enumerated changes. This is particularly true given the breadth of the proposed expansion to the corporate association disclosure obligation and the new proposed obligations with respect to disclosure of "all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings…".

Under the Proposed Amendments, if a new indirect corporate association should come into existence within the 30 days preceding an auction, CARB could bar the entity from participation in the auction. This is even though the auction participant might not know about or control the existence of the new indirect corporate association and regardless of whether the new association has any relationship to, or involvement in, the Cap-and-Trade program. Given the complex corporate structures of some auction participants and the limitations on their ability to either control or receive notice of changes occurring with respect to entities with whom they may have only an attenuated relationship (i.e., indirect corporate associations), Calpine thinks it is unworkable for CARB to bar participation in such circumstances.

As another example, if a previously disclosed individual with access to information on compliance instrument holdings should be replaced during the 30 days prior to an auction (due to illness, termination, etc.), the simple act of hiring a new employee to replace that person could result in disqualification. Given the hundreds of individuals who may have access to such information in any company (including information technology personnel, systems analysts and accounting personnel) and the probability that any one of them might need to be replaced in any 30-day period, it seems likely that many auction participants could be susceptible to disqualification from some, if not most, auctions.

For the foregoing reasons, Calpine would urge CARB not to adopt section 95912(d)(5). If CARB proceeds to finalize this section, however, the only changes that should bar participation in the auction are those affecting direct corporate associations also registered within CITSS which occur prior to an auction, i.e., disqualification may only be triggered by changes in auction application information that could affect computation of the holding limit or auction purchase limit or concerning the status of certain regulatory investigations, as follows:

§ 95912. Auction Administration and Participant Application.

(d) Auction Participation Application Requirements.

(5) An entity with any changes to the auction application information listed in subsection 95912(d)(4) pertaining to the entity itself or any direct corporate association also registered pursuant to this article~~or account application information listed in section 95830~~ within 30 days prior to an auction~~, or any entity whose auction application information or account application information listed in section 95830 will change within 15 days after an auction,~~ may be denied participation in the auction....

These proposed amendments would ensure two things:

- The integrity of certified auction results will not be threatened by the possibility that auction participants could be barred from participation due to changes occurring after an auction has already occurred and the results have been certified.
- Auction participants with complex corporate structures and many employees with access to procurement information will not be unfairly barred from participation due to changes occurring outside of their sphere of direct knowledge or control or inconsequential changes in personnel. (CALPINE 1)

Comment: Limit the entity information that must not change in the weeks surrounding an auction or reserve sale

A. Revise section 95912(d)(5) on information that cannot change in the 45 days surrounding an auction.

Proposed new section 95912(d)(5) provides that an entity whose auction application information listed in section 95912(d)(4) or account application information listed in section 95830 will change 30 days prior or 15 days after an auction may be denied participation in the auction. If an entity wishes to participate in all four auctions in a year, it must ensure that this information does not change for 180 days in total – nearly half the year. It will be very difficult, if not impossible, to ensure this information does not change for such a large part of the year.

Account application information listed in section 95830 includes the proposed new requirement to list the entity's employees with information on compliance instrument transactions or holdings (section 95830(c)(1)(I)), as well as the entity's directors and officers and cap-and-trade consultants and advisors (sections 95830(c)(1)(B) and (J)). These people, particularly the employees with information on compliance instrument transactions or holdings, may change from time to time. An entity cannot prevent its employees from resigning for 180 days of the year. Entities should not be barred from participating in auctions merely because one of their employees chooses to leave in the 45-day period surrounding an auction.

Auction application information includes an attestation that the entity and its associates have not been subject to any previous or ongoing investigations, including a change in the status of an ongoing investigation (section 95912(d)(4)(E)). Even if the changes requested in section XII above are made, an investigation may be unexpectedly commenced or the status of an existing investigation may change in the 45-day period surrounding an auction. This should not prevent an entity participating in the auction.

SCPPA understands that the ARB wishes to ensure certain basic information, such as an entity's legal status and its ownership of a holding account, remains unchanged for a reasonable period surrounding each auction, so the ARB can correctly process auction applications and correctly distribute allowances to winning bidders. However, the list of information that must remain unchanged as per proposed new section 95912(d)(5) goes far beyond this objective. This section should be revised to allow changes to an entity's employees with information on compliance instrument transactions or holdings, its directors and officers, its cap-and-trade consultants and advisors, and its list of investigations.

> **Recommendation:** SCPPA's proposed changes to section 95912(d)(5) are set out below:
>
> (5) An entity with any changes to the auction application information listed in subsection 95912(d)(4) <u>(other than subsection 95912(d)(4)(E))</u> or account application information listed in section 95830 <u>(other than subsections 95830(c)(B), (I) and (J))</u> within 30 days prior to an auction, or an entity whose auction application information <u>(other than information pursuant to subsection 95912(d)(4)(E))</u> or account application information listed in section 95830 <u>(other than subsections 95830(c)(B), (I) and (J))</u> will change within 15 days after an auction, may be denied participation in the auction. (SCPPA 1)

Comment: Revise section 95913(e)(2) on information that cannot change in the 35 days surrounding a Reserve sale: Proposed new section 95913(e)(2) provides that an entity with auction application information listed in section 95912(d)(4), or account application information listed in section 95830, that changes 20 days prior to or 15 days after a Reserve sale may be denied participation in that Reserve sale. For the reasons outlined in section XIII.A above, this section should be revised to allow an entity to participate in a Reserve sale despite changes to its employees with information on compliance instrument transactions or holdings, its directors and officers, its cap- and-trade consultants and advisors, and its list of investigations.

> **Recommendation:** SCPPA's proposed changes to section 95913(e)(2) are set out below:
>
> An entity with any auction application information listed in subsection 95912(d)(4) <u>(other than subsection 95912(d)(4)(E))</u>~~above~~ or account application information listed in section 95830 <u>(other than subsections</u> <u>95830(c)(B), (I) and (J))</u> that changes <u>within</u> 20 days prior to a reserve sale, or <u>within</u> 15 days after a reserve sale, may be denied participation in a reserve sale. (SCPPA 1)

Comment: Sections 95912 and 95914. ARB Should not Unreasonably Restrict an Entity's Auction Participation

1. Auction or Account Changes Should Not Jeopardize Auction Participation

PG&E opposes Section 95912(d)(5) of the proposed amendments, which may bar an entity from participating in an auction if there are changes to information provided in an entity's auction or account application 30 days before or 15 days after an auction. This proposal is unduly restrictive and should be removed. While this restriction may pose a challenge for any compliance entity, large compliance entities are especially impacted by this provision due to the size and complexity of their business operations. The activities described in the auction or account application cover a range of activities that a company may need to perform in the course of its business and simply cannot remain static for 180 days a year in order to participate in the Cap- and-Trade auctions.

For example, an entity may need to raise capital to finance its activities, impacting information provided in its auction application. Proposed Section 95912(d)(5) jeopardizes an entity's ability to participate in ARB auctions because of such an activity. Further, the proposed amendments modify an entity's registration requirements, including a comprehensive contact list of employees involved in decisions, or with access to information, concerning Cap-and-Trade compliance instrument transactions or holdings. Section 95912(d)(5) unreasonably threatens an entity's auction participation based on changes to this list. This restriction is unnecessarily burdensome for large compliance entities with many employees working on Cap-and-Trade Program issues. It is unreasonable to assume an entity can prevent employee job functions from changing within each of these 45-day periods.

While ARB staff acknowledges that Section 95912(d) is intended to facilitate effective settlement of the auctions and support market monitoring, and is not intended to be overly burdensome, Section 95912(d) should be rejected because it unnecessarily jeopardizes an entity's auction participation for activities associated with its normal business operations. If the ARB does not remove this provision, PG&E suggests that

ARB instead require the entity to update repotting materials within 10 days of changes to the auction or account application information.

> **Recommendation:** PG&E proposes that Section 95912(d)(5) be revised as follows:
>
> An entity with any changes to the auction application information listed in subsection 95912(d)(4) or account application information listed in section 95830 within 30 days prior to an auction, or an entity whose auction application information or account application information listed in section 95830 ~~will~~ changed ~~within~~15 days after an auction shall update the information listed in 95912(d)(4) within 10 working days of such change.~~ may be denied participation in the auction.~~

PG&E's proposal is consistent with Section 95830 (f), which requires registrants to update changes to registration within ten working days of changes. Notification of such change, and updated auction and/or account information would provide ARB the information it requires to effectively monitor each auction without jeopardizing an entity's participation, facilitating the intent of ARB staff in proposing Section 95912(d)(5). If ARB will not reject or revise the above provision, the Regulation should at a minimum identify the specific information of concern set forth in Section 95912(d)(4) and Section 95830 that would preclude auction participation. (PGE 2)

Comment: § 95912 auction administration and participant application: CARB is proposing the following new provision (§ 95912(d)(5)):

> An entity with any changes to the auction application information listed in subsection 95912(d)(4) or account application information listed in section 95830 within 30 days prior to an auction, or an entity whose auction application information or account application information listed in section 95830 will change 15 days after an auction, will be denied participation in the auction.

The ISOR states that the new provision is necessary to ensure correct processing of the auction applications. However, the proposal is broadly written such that any changes in an entity's auction or account application will result in denial of the entity's ability to participation in the auction. LADWP believes that this requirement would be too restrictive and recommends that CARB more narrowly define what constitutes a "change" that would lead to denial of an entity to participate in an auction. It would be extremely difficult for an entity to have no changes (e.g. changes in an entity's directors and officers) to its auction application information within the time period stated, especially if the entity plans on participating in all four auctions throughout a compliance year (e.g. could be 180 days out of a compliance year). In addition, 15 days after an auction, the entity will have already participated in the auction as far as submittal of bids and may not be able to predict if its auction application information will change in that time period. (LADWP 1)

Comment: Fifth and lastly, a new section would bar an entity's participation in an auction if the information provided in the entity's auction or account application changes 30 days before or 15 days after an auction. If an entity wanted to participate in all four auctions each year, the entity would have to make sure nothing in its auction or account application changed for 180 days out of the year. That's excessive and should be changed. We hope to see 45-day language that makes provisions consistent with these comments and our written comments. Thank you. (SCPPA 3)

Comment: Moreover, additional, significant and unreasonable impact could occur when these changes are coupled with additions to subsection 95912(d)(5) which now reads: an entity with any changes to the auction application information listed in subsection 95912(d)(4) or account information listed in Section 95830 within 30 days prior to an auction, or an entity whose auction application information will change 15 days after an auction, may be denied participation in the auction. BP routinely buys and sells business lines in response to changes in the prospects of particular products or markets around the world. When combined, these new changes mean that if BP buys or sells an entity, or changes a corporate association anywhere in the world within 30 days prior to or 15 days after an auction, regardless of whether that associated entity has any involvement in the California cap and trade program – BP, a regulated entity with a large compliance obligation, may be denied participation in the auction. This is simply unreasonable by any standard. (BP 1)

> **Response:** In response to stakeholder comments, ARB staff has narrowed the scope of the auction application requirements to only reflect changes to the auction application and not changes to company registration with ARB. Likewise, staff has removed text that would prevent information in the auction and reserve sale application from changing 15 days following the auction. The restriction to changes within 30 days prior to auction is necessary to ensure correct processing of the auction applications. ARB staff believes these 15-day changes effectively address stakeholders' comments.

H-3. Trading

H-3.1. Comment: Chevron is concerned with the trade restrictions and market complexity introduced in the proposed amendments. These proposed restrictions will eliminate critical transactions such as options, futures, forwards, right of first refusal contracts. These promote a robust and efficient market structure. Chevron understands the agency's need to identify bad actors, but rules must be designed so that honest parties are able to avoid inadvertent missteps.

ARB should provide guidance similar to guidance issued for resource shuffling that explains specific safe harbors or specific examples of bad behavior. This is needed in the rulemaking to provide some measure of definition to allow regulated parties to understand the limits or boundaries that ARB means to enforce. (CHEVRON 2)

Response: ARB staff does not agree that the proposed amendments will eliminate critical transactions. Staff does not intend to restrict trade or market liquidity, but rather to protect the market from manipulation through adequate monitoring, to enable a competitive market, and to promote a robust and efficient market structure. Section 95921(f) defines prohibitions on trading.

Holding on Behalf

H-3.2. Comment: General Prohibitions on Trading (S95921(f), page 202): ARB has proposed language that prohibits an entity from holding allowances for another entity that has ownership or financial interest in those allowances, unless the entities share a direct corporate relationship. While such a requirement is understandable to ensure that a bank does not hold allowances for an industrial entity in order to get around a holding limit, the language is not clear enough to allow direct or indirect entities to hold allowances for each other. The ownership issue and financial interests could become muddy due to corporate structures.

WSPA is concerned with the trade restrictions and market complexity introduced in the proposed amendments. These proposed restrictions will eliminate critical transactions such as options, futures, forwards, and right of first refusal contracts. These types of transactions promote a robust and efficient market structure. WSPA understands the agency's need to identify "bad actors", but rules must be designed so that honest parties are able to avoid inadvertent missteps.

ARB should provide guidance similar to guidance issued for resource shuffling that explains specific safe harbors or specific examples of bad behavior. This is needed in the rulemaking to provide some measure of definition to allow regulated parties to understand the limits or boundaries that ARB means to enforce.

Prohibitions on trading are generally overbroad and should be curtailed to permit legitimate transactions that support program objectives and create liquidity. For example, requiring that "an entity cannot acquire allowances and hold them in its own holding account on behalf of another entity" could be interpreted to interfere with the ability of entities to purchase allowances from market makers at auction prices.

ARB should provide a safe harbor for forward contracts under the trading prohibition. The new proposal includes additional language that deviates materially from the guidance provided by ARB in December 2012. The new language uses very broad language that could be read to mean that the safe harbor is practically inaccessible. This language needs to be scaled back to be consistent with the December 2012 guidance.

Additionally the beneficial holdings provisions do not allow escrow arrangements because by definition, such arrangements involve a holding on behalf of another. Escrow is a fundamental component of corporate transactions and this could create unnecessary obstacles to numerous corporate transactions involving covered entities.

We support the addition of a safe harbor for escrow accounts, in addition to the safe harbor for forward contracts and for direct corporate associations.

Recommendation: Delete the proposed changes to Prohibitions on trading requirements. (WSPA 1)

> **Response:** The new 15-day language in section 95921(f)(1) is added to clarify the existing prohibition against an entity holding compliance instruments in its account on behalf of another entity. The new text places in regulation the explanation currently in ARB's regulatory guidance document of the existing text. Under the existing rule text and guidance, ARB has observed growth in the use of forward, futures and options contracts. ARB has also observed the use of contracts in which the price is specified as equal to a margin plus a known cost basis, such as an auction settlement price. ARB has made it clear these types of transaction agreements do not violate the prohibition on beneficial holdings. ARB interprets the growth in use of these instruments as evidence that the rules are understood and are not interfering with transactions.

H-3.3. Comment: Prohibition on holding "on behalf of" another entity: The Proposed Amendments include additional criteria intended to clarify that forward contracts are not subject to the prohibition of an entity holding allowances on behalf of another entity. However, these criteria may outlaw many common arrangements for delivery of allowances between parties to power sales contracts. Rather than treat power sales contracts as a subset of forward contracts, Calpine urges CARB to adopt an express exception, clarifying that the prohibition does not apply to procurement of allowances by the buyer under a power or steam sales contract, for later transfer to the seller to cover the compliance obligation associated with deliveries of electricity and steam.

CARB should clarify that allowance procurement to fulfill a power or steam sales contract is not unlawful: Section 95921(f)(1) of the Cap-and-Trade Regulation currently prohibits an entity from acquiring and holding allowances in its own holding account on behalf of another entity. As we suggested when this section was initially proposed, this could be interpreted to prohibit an entity from ever acquiring allowances on behalf of another entity, including under common arrangements between utilities and power suppliers. CARB subsequently published guidance that clarified that the prohibition was not intended to apply to such arrangements between utilities and their contractual counterparties. However, the Proposed Amendments would impose additional criteria that could be interpreted to proscribe just such arrangements. We would therefore urge CARB, upon finalizing the Proposed Amendments, to incorporate an express statement in the Regulation which clarifies that arrangements between parties to energy sales contracts concerning procurement and delivery of allowances are lawful, as described below.

The Proposed Amendments would establish three additional restrictions on section 95921(f)(1), including, inter alia, "[a]n entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments reside in the first entity's accounts, or control over the acquisition of allowances by the first entity. These prohibitions do not apply to agreements that only specify a date to deliver a specified quantity of allowances and that include no terms applying to allowances residing in another entity's account." CARB explains in the ISOR that the Proposed Amendments are "needed to clarify that the prohibition on 'holding on behalf of'" does not apply to, inter alia, "forward contracts that do not contain terms applying to the compliance instruments in the first entity's account."

In its official regulatory guidance document, CARB explained that the existing Regulation's prohibition is not intended to apply to forward contracts, including several variations of contracts utilized in the electricity sector whereby one party agrees to periodically transfer allowances to its counterparty. CARB said it "views these contracts as essentially no different than forward contracts and, accordingly, they will not be barred by the Regulation, so long as the contract does not (1) give the ultimate recipient control of compliance instruments while they are still in the account of the entity from which they will be received, and (2) does not recognize any ownership interest by the ultimate recipient in the compliance instruments while they are still in such entity's account."

In light of the Guidance Document's statement that contracts between utilities and electric generators are viewed as essentially the same as lawful forward contracts, we assume that the Proposed Amendments likewise intend to authorize procurement and delivery of allowances pursuant to such utility-generator contracts. However, rather than provide clarity, the additional criteria that would be added by the Proposed Amendments suggest that deliveries of allowances pursuant to the terms of many common power sales contracts are prohibited. By requiring that lawful contracts "only specify a date to deliver a specified quantity of allowances and include no terms applying to allowances residing in another entity's account", the Proposed Amendments could be interpreted to outlaw many standard form contracts used today by the investor owned utilities ("IOUs") to address GHG allowance costs.

The terms of standard IOU contracts often do not include any date-certain for transfer of a specified quantity of allowances, but instead provide the formula for determining how many allowances will be transferred and the relative time of delivery. Unlike bilateral forward contacts or futures, the quantity of allowances to be delivered is rarely (if ever) specified in the contract and the date when delivery must occur may be as indefinite as a reasonable amount of time prior to a compliance obligation becoming due for emissions associated with delivered energy. This is not because such contracts are purposefully vague, but rather because the volume to be delivered cannot be projected with any accuracy and depends on how frequently the contracted unit is dispatched by the utility, which cannot be known in advance and is subject to the many unpredictable factors that influence both demand for electricity and dispatch of electric generating resources; e.g., weather, the quantity of hydropower available and availability of other generating resources. A typical contract might only provide for the generator to report its estimated GHG emissions on a regular monthly invoice, with delivery of the accrued emissions to occur at some later date, prior to the relevant compliance deadline. Thus, such contracts might not be viewed as “specify[ing] a date to deliver a specified quantity of allowances” as required by the Proposed Amendments.

In addition, these contracts often include many additional terms that, although not giving one entity control over allowances in its counterparty’s account, might nevertheless be viewed as “applying to allowances residing in another entity’s account.” For example, they often provide that, if a compliance instrument delivered to the seller should later be invalidated, the buyer will replace it. With some variation, the contract terms also often provide that, if the generator or any of its affiliates should later receive any sort of free allocation with respect to the power delivered under the contract, it is obliged to share some amount of that allocation with the utility. Additionally, such contracts may mandate that the party to whom allowances are delivered will use them to satisfy a compliance obligation. While these terms do not provide one party control over allowances in another’s account, they might nevertheless be viewed to run afoul of the Proposed Amendments, which mandate that lawful contracts “include no terms applying to allowances residing in another entity’s account.”

Counterparties to power or steam sales contracts may have any number of reasons for agreeing to the periodic transfer of allowances, in lieu of settling with one another financially for the compliance obligation attributable to deliveries of power or steam. This may be based on the parties’ assessment of their relative ability to assume the risk of price fluctuations in the market for compliance instruments or their relative sophistication with respect to participation in the auction and/or the secondary markets. Regardless of the reason, the Proposed Amendments should not foreclose the development of appropriate commercial vehicles for parties to assure that the compliance obligation is satisfied with respect to sales of electricity or steam.

If counterparties to power sales contracts are precluded from entering into reasonable commercial arrangements that spell out exactly how they will calculate the quantity of emissions attributable to dispatch of a generating unit, who will be responsible for procuring the compliance instruments to cover those emissions, and when and how they will effectuate delivery of those compliance instruments, the parties would face significant uncertainty with respect to satisfaction of the compliance obligation attributable to contracted generation. CARB should not force the parties to shoulder such uncertainty and administrative burden due to a lack of clarity in its Regulation.

Because the existing Regulation’s prohibition has already raised interpretive questions, Calpine proposes that CARB revise the Proposed Amendments to make clear that the prohibition on entities acquiring and holding allowances on behalf of another entity does not apply to an agreement between a buyer and seller of electricity or steam, pursuant to which the buyer provides compliance instruments to cover emissions attributable to delivered power or steam.

Recommendation: Accordingly, Calpine proposes the following revision to section 95921(f)(1) of the Proposed Amendments:

§ 95921. Conduct of Trade.…

(f) General Prohibitions on Trading.

(6) An entity cannot acquire allowances and hold them in its own holding account on behalf of another entity ~~I~~including the following restrictions:

(B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments reside in the first entity's accounts, or control over the acquisition of allowances by the first entity. These prohibitions do not apply to agreements for the purchase and sale of electricity and/or steam, pursuant to which the purchaser agrees to provide compliance instruments to the seller to account for the Emissions attributable to the electricity and/or steam delivered thereunder, and agreements that only specify a date to deliver a specified quantity of allowances and that include no terms applying to allowances residing in another entity's account. (CALPINE 1)

Response: The change proposed in the comment is not needed because existing and proposed language allow transaction agreements in which the purchaser of a product commits to providing the seller with the number of compliance instruments needed to cover the emissions obligation incurred in producing the product. ARB understands the existing and proposed language to only prohibit the existence of an ownership interest by an entity of compliance instruments as they reside in another entity's account. The concern in the comment appears focused on language in section 95921(f)(1)(B) in the 45-Day Public Notice that refers to "terms applying to allowances residing in another entity's account." ARB staff is now proposing to replace that language with text that, in ARB's estimation, matches the intent of the language proposed in the comment.

H-3.4. Comment: Prohibitions on trading are generally overbroad and should be curtailed to permit legitimate transactions that support program objectives and create liquidity. For example, requiring that "an entity cannot acquire allowances and hold them in its own holding account on behalf of another entity" could be interpreted to interfere with the ability of entities to purchase allowances from market makers at auction prices.

The Proposed Regulation Order includes additional language that deviates materially from the guidance provided by ARB in December 2012 (which Chevron supports). The new language uses very broad language that could be read to prohibit legitimate transactions discussed above. This language needs to be scaled back to be consistent with the December 2012 guidance – or at the very least, ARB needs to explain why it is making changes to its December 2012 position.

Additionally the prohibition on beneficial holding does not allow escrow arrangements, because by definition, such arrangements involve a holding on behalf of another. Escrow is a fundamental component of corporate transactions and this could create unnecessary obstacles to numerous corporate transactions involving covered entities. We support the addition of a safe harbor for escrow accounts, in addition to the safe harbor for forward contracts and for direct corporate associations.

Chevron believes that market makers have an important role to assist entities that need to participate in the market but do not have internal resources devoted to learning all the detailed rules. ARB should support this role. We support workable rules for market makers that do not increase their market power.

Market Prohibitions: Issue: the proposed language deviates materially from the guidance provided by ARB in December 2012 because it could be read to prohibit transactions such as options and right to match terms.

> **Recommendation:** Proposed Change: clarify the prohibition by adding new safe harbors in Section 95921(f) for certain transaction types.
>
> Market Prohibitions:
>
> § 95921. Conduct of Trade.…
>
> (b) Information Requirements for Transfer Requests. Parties to the transfer request agree to provide documentation about the transaction agreement for which the transfer request was submitted upon the request of the Executive Officer. The following information must be reported to the accounts administrator as part of a transfer request before any transfer of allowances can be recorded on the tracking system:…
>
> (6) If the transaction agreements do not contain a price for compliance instruments, entities may enter a price of zero into the transfer request if the transfer request is submitted to fulfill one of the following transaction agreement types and the entity discloses the agreement type in the transfer request....
>
> <u>(G) The proposed transfer is from an entity that is a party to an escrow agreement to an entity designated as escrow agent pursuant to the same escrow agreement.</u>
>
> <u>(H) The proposed transfer is from a borrower to a secured party.</u>
>
> (f) General Prohibitions on Trading.

(5) An entity cannot acquire allowances and/or hold them in its own holding account on behalf of another entity,~~. I~~including the following restrictions:

(A) An entity may not hold allowances in which a second entity has any ownership ~~or financial~~ interest.

(B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments reside in the first entity's accounts~~, or control over the acquisition of allowances by the first entity~~. ~~These prohibitions do not apply to agreements that only specify a date to deliver a specified quantity of allowances and that include no terms applying to allowances residing in another entity' s account~~

(C) Notwithstanding the prohibitions in section 95921(f)(1)(A)-(B), the following transactions are permitted:

(i) An entity may ~~purchase~~acquire and/or hold allowances for ~~later transfer to~~ members of a direct corporate association.

(ii) An entity may acquire and/or hold allowances subject to a purchase and sale agreement for future delivery to a purchaser, provided that the purchase and sale agreement does not allow the purchaser to gain an ownership interest in allowances until they are transferred to the purchaser's account.

(iii) An entity acting as escrow agent pursuant to an escrow agreement may acquire and hold allowances on behalf of the party or parties to the transaction subject to the escrow agreement.

(iv) An entity may hold allowances in which another entity has an ownership interest as a pledge or as collateral pursuant to a secured transaction, provided that the holding entity may not sell, transfer, retire or otherwise use the allowances unless such action is in accordance with the secured transaction. Upon a default in the secured obligations, the secured party may take ownership of the allowances and/or transfer them to a third party in connection with its exercised remedies against the collateral.

(v) An entity may acquire and/or hold put, call or right of first refusal options to purchase or sell allowances that reside in another entity's account. (CHEVRON 2)

Response: Staff has removed the reference to financial interest in section 95921(f)(5)(A) in the 15-day changes. Staff has maintained the text in section 95921(f)(5)(B) because it is essential in explaining the types of transaction agreements that are acceptable given the prohibitions on beneficial holding.

Staff did not make the suggested change in section 95921(f)(5)(C) because the proposed text does not specify how ARB would apply the holding limit to such transactions. As written (C)(v) appears to completely undermine ARB's ability to enforce the holding limit. During the regulation proceedings in 2011 staff worked with stakeholders on proposals to include escrow-type arrangements in a separate section on beneficial holdings. At that time staff was unable to resolve issues of who actually controls the allowances versus how the allowances would count towards the holding limit.

H-3.5. Comment: Section 95921(f)(1)(A): New Section 95921(f)(1)(A) specifies that "[a]n entity may not hold allowances in which a second entity has any ownership or financial interest."

Recommendation: CPEM recommends that this section be modified as set forth below to clarify that this section is not intended to limit an entity's ability to enter into secured transactions or financing agreements in which allowances may be used for collateral.

95921(f)(1)(A) specifies that "[a]n entity may not hold allowances in which a second entity has any ownership or financial interest. <u>These prohibitions do not apply to financial interests created for financing or collateral purposes.</u> (CPM 1)

Response: ARB staff did not make the proposed change because the language is too broad. Instead, ARB proposed 15-day changes to remove the reference to financial interest from the text.

H-3.6. Comment: Prohibitions on Trading – Section 95921(f): We share staff's desire to avoid market manipulation but believe the language in this section addressing acquiring or holding of allowances is too broad and can result in unnecessary restrictions for very valid cases of an entity holding allowances for an affiliated entity.

Recommendation: To address these concerns, we suggest the following language changes:

(1) <u>The ability for one entity to acquire allowances and hold them in its own holding account on behalf of another entity are limited as following</u>:

(A) An entity may not hold allowances in which a second entity has any ownership or financial interest <u>unless the second entity is disclosed as a</u>

corporate association under section 95833 or unless that second entity is an affiliated entity which is not a covered entity and/or not qualified to be an opt-in covered entity or voluntarily associated entity.

(B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the ~~instruments~~ allowances reside in the first entity's accounts, or control over the acquisition of allowances by the first entity. These prohibitions do not apply to agreements that only specify a date to deliver a specified quantity of allowances and that include no terms applying to allowances residing in another entity's account or to holding of allowances by or for corporate associations disclosed in section 95833 or to an affiliated entity which is not a covered entity and/or qualified to be an opt- in covered entity or voluntarily associated entity. (BP 1)

Response: ARB decided not to make the recommended change because it would have the effect of rendering the holding limit and market monitoring efforts useless. The existing regulation already allows holding of allowances by members of a direct corporate association for later transfer to other members of the same corporate association. This is allowed because ARB assumes members of a direct corporate association coordinate all market decisions and therefore ARB subjects all members to a single holding limit calculation. The proposed change would extend the exemption to the prohibition of beneficial holding to members of corporate associations that are not constrained by a single holding limit. The proposed changes would also allow beneficial holding on behalf of unregistered parties that would remain unknown to ARB, thus rendering ARB unable to determine who controls compliance instruments.

H-3.7. Comment: Prohibited and Permitted Trading Activities Should be Clarified

The changes to Section 95921(f) listed below are intended to better clarify which trading activities are prohibited and which are permitted.

(1) An entity cannot acquire allowances and hold them in its own holding account on behalf of another entity. ~~Including~~ This prohibition shall restrict the following ~~restrictions~~ activities

(A) An entity may not hold allowances in which a second entity has any ownership or financial interest.

(B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments reside in the first entity's accounts, or control over the acquisition of allowances by the first entity.

~~These s~~ This Section 95921(f)(1) does not prohibit agreements that only specify a date or time period to deliver a specified quantity of allowances and that do not include ~~no~~ terms applying to allowances residing in another entity's account or~~(Can~~ entity from purchasing and holding allowances for later transfer to members of a direct corporate association. (PGE 2)

> **Response:** Staff appreciates the assistance in clarifying the requirement. Staff has edited the subsection in 15-day changes to specify that members of a direct corporate association may purchase compliance instruments on behalf of one another. The recent update also specifies that provisions stating a date and time period for the delivery of compliance instruments also do no violate the Regulation.

H-3.8. Comment: Transfers of compliance instruments between accounts (§ 95921(a)(4)): The proposed amendment to Section 95921(a)(4) would provide that "[a]ny entity may not submit a transfer request to another registered entity without an existing transaction agreement with that party authorizing a transfer." Currently, APS only purchases California carbon allowances on ICE through ICE clearing. APS will not be notified of the counterparty's name by our clearing bank until the settlement date. We believe the current ICE standard contract is "an existing transaction agreement." We also believe our current business practice satisfies the requirement of this proposed language. We request clarification if CARB disagrees with our interpretation and analysis.

APS appreciates the opportunity to submit these comments and thanks CARB for its consideration thereof. (APS)

> **Response:** Transactions conducted on the ICE do not result in the submittal of a transfer request to CITSS until the parties are informed by an ICE member clearing entity that the contracts have gone to settlement. For that reason, staff agrees with APS' conclusion that the ICE standard contract complies with the proposed requirement.

H-3.9. Multiple Comments: Section 95921(a)(4): New section 95921(a)(4) specifies that "an entity may not submit a transfer request to another registered entity without an existing transaction agreement with that party authorizing a transfer." CPEM believes this provision is unnecessary. If it is included, ARB should clarify that such agreement need not be a formal written document. Many registered entities are sophisticated parties that routinely operate in energy and commodity markets, and frequently close transactions based on oral agreement (generally recorded), instant message, or other form of communication. Such transactions may rely on a master agreement for additional terms and conditions, may rely on interpretation under the Uniform Commercial Code, and/or may rely on other legal principles, such as course of dealings between the parties. (CPM 1)

Comment: The proposed language in section 95921(a)(4) states that "an entity may not submit a transfer request to another registered entity without an existing transaction agreement with that party authorizing a transfer."

IETA's membership believes this provision is unnecessary and problematic. Many registered entities are sophisticated parties that routinely operate in energy and commodity markets, and frequently close transactions based on oral agreement (generally recorded), instant message, or through other forms of communication. Such transactions may rely on a master agreement for additional terms and conditions, may rely on interpretation under the Uniform Commercial Code, and/or may rely on other legal principles, such as course of dealings between the parties.

IETA recommends that if such a provision is included, ARB should clarify that such an agreement need not be a formal written document. (IETA 1)

> **Response:** ARB staff understands the concern expressed in the comments. Staff has made changes in the 15-day language to clarify that the agreement may be a "written or recorded oral" agreement, and believes the examples raised by the comments would not constitute violations of the provisions. Staff has reviewed a number of transaction agreements in which decisions to trade are based on oral agreements made under a master agreement. The master agreements typically require written follow-up confirmations of oral agreements.

Compliance Instrument Transfer Reporting

H-3.10. Comment: Requirements for transfer requests must be changed to reflect established transactional processes: SCE appreciates the ARB's attempt to clarify the term "settlement date" as it relates to transfer requests for transferring compliance instruments between accounts. However, the ARB should modify Section 95921(a)(3) of the Proposed Regulation Order to match established transactional protocols. Specifically, the term "execution date" typically refers to the date on which the terms of a (bilateral or exchange) contract are agreed to, not the date on which a transfer is scheduled to occur. The proposed language, as written, could cause confusion. For example, SCE may execute a futures trade over the Intercontinental Exchange on October 11, to purchase 10,000 allowances that will be delivered on December 30. Payment to the seller will not be released until after SCE confirms receipt of the 10,000 allowances on December 30. Under Section 95921(a)(3)(D), the transfer request for this transaction would have to be completed by October 14 even though the delivery under the exchange contract is not scheduled to occur until December 30.

> **Recommendation:** To clarify the requirements for transfer requests, SCE suggests the following changes to Section 95921(a)(3):
>
> (3) The parties to a transfer will be in violation and penalties may apply if the above process is <u>not</u> completed:

(A) Within~~More than~~ three days of~~after~~ the initial submission of the transfer request; ~~or~~and

(B) Within~~More than~~ three days of~~after~~ the delivery~~execution~~ date or termination date ~~settlement day~~ of the transaction agreement for which the transfer request is submitted; or if the above process is completed:

(C) More than three days after the transfer of consideration from the purchaser of the compliance instrument to the seller as provided by the transaction agreement; or

(D) More than three days after the ~~execution~~ payment ~~of~~for the compliance instrument(s) ~~underlying~~ traded on an exchange or other trading platform is received by the seller of the compliance instrument.

In addition, SCE suggests the following change to the definition in Section 95802(130):

"~~Execution~~Delivery Date" means the date specified in a transaction agreement prior to which ~~a provision of a transaction agreement that requires~~ the transfer of compliance instruments ~~on or before a date specified in the agreement~~ must occur. (SCE 1)

Response: In response to comments, staff has removed the definition of "Execution Date" in the 15-day amendments. Moreover, staff changed former proposed section 95921(a)(3) to (a)(4) and the 15-day changes now require the entry of the "expected termination date of the agreement," rather than a "execution date." Staff made these changes because staff agrees with comments that the concept of "execution date" did not fit the wide variety of transaction agreements in effect. Staff had originally included the term to try and capture multiple transfers occurring under a single transaction agreement or a single transfer to be completed before other terms in the agreement. Staff also removed subparagraphs (C) and (D). These changes improve the clarity of the provision and staff does not believe the additional changes proposed by the commenter are necessary.

H-3.11. Multiple Comments: Section 95921. ARB should not impose unreasonable transfer requirements because the current regulation provides significant transparency: The Joint Utilities oppose ARB's proposed amendments to Section 95921(a)(3) which impose penalties on parties to a contract involving a transfer of compliance instruments if the compliance instrument transfer occurs more than three days after the execution date or termination date of the transaction agreement, or more than three days from the date of "transfer of consideration from the purchaser of the compliance instrument to the seller." Parties to contracts involving compliance instruments should be able to structure the transfer of allowances and payments (including deposits, guarantees and other early payments) in a manner appropriate to the underlying transaction.

The Joint Utilities are concerned that the proposed rules will have the unintended consequence of unduly complicating transactional structures for compliance instruments, resulting in increased costs of compliance. Moreover, we question ARB's need to prohibit certain transactional provisions given the current robust suite of market monitoring tools provided in Section 95921, which provides the agency with sufficient information to monitor participants and the market without the additional requirements proposed under 95921(b)(3). (JUC)

Comment: CARB has clarified the existing requirement in section 95921(a)(3) that transfer of compliance instruments in CITSS be completed within three days of the settlement date of the transaction. A transfer would now be considered deficient if it is not concluded within three days of a) submission of the transfer request, b) the execution date or termination date of the transaction agreement, c)"transfer of consideration from the purchaser of the compliance instrument to the seller as provided by the transaction agreement" or d) "the execution of the underlying trade on an exchange or other trading platform."

We understand that from a house-keeping perspective, it is necessary for CARB to impose a deadline on completion of transfer in CITSS to prevent initiated transfers to remain in an incomplete status indefinitely and to ensure that the transaction is completed within 3 days of the transfer of compliances as set out in the underlying transaction agreement. We therefore do no object to the proposed changes to sub–paragraphs a, b and the addition of new sub-paragraph d.

However, we are concerned by CARB's addition of sub-paragraph c. Staff further explains in the Initial Statement of Reasons that the 'transfer of consideration' refers to the time at which payment by the purchaser gives it a financial interest in the allowances, and that the requirement is necessary to prevent the seller from holding the allowances on behalf of the buyer. WPTF objects to this addition for two reasons. First, the transfer of financial consideration, as staff have phrased it, is not coincident with the transfer of title to compliance instruments. Rather, title transfer is usually dictated by the terms of the contract. Until transfer of title, the compliance instruments belong to the seller – thus there can be no holding on behalf of the buyer.

Second, the requirement would appear to prohibit buyers with poor credit to pre---pay or post collateral for allowances to be received at a later date. This would harm smaller players and reduce liquidity in the secondary market.

WPTF recommends that CARB delete section 95921(a)(3)(c). The 3 day timeframe for transfer should be linked to the date of title transfer in the transaction agreement, as set out in (b) and (d). (WPTF 1)

Comment: Deadlines to complete transfer requests should be revised: Section 95921(a)(1)(E) of the Regulation requires compliance instrument transfer requests to be completed within three days of "settlement" of the transaction agreement for which the transfer request is submitted. Section 95921(a)(3) further provides that entities will be in violation and penalties may apply if compliance instrument transfer requests are completed:

(A) More than three days after the initial submission of the transfer request; or

(B) More than three days after the execution date or termination date of the transaction agreement for which the transfer request is submitted; or

(C) More than three days after the transfer of consideration from the purchaser of the compliance instrument to the seller as provided by the transaction agreement; or

(D) More than three days after the execution of the underlying trade on an exchange or other trading platform.

“Execution date” in section (B) means a date set out in the agreement by which compliance instruments must be transferred (section 95802(a)(130)).

A. Sections 95921(a)(1)(E) and 95921(a)(3)(B) to (D) should be deleted.

These provisions are problematic from a policy perspective and a practical perspective. It is unnecessary and inappropriate for the ARB to impose a transfer deadline relating to the transaction agreement. Transaction agreements themselves will contain provisions on the dates by which transfers must be completed, and they will also contain penalty provisions if these dates are not met. It should not be relevant to the ARB whether an entity completes a transfer request by the date specified in the transaction agreement or within a certain time of the transfer of consideration, or completes it later, as the ARB does not enforce transaction agreements. Therefore, SCPPA considers that sections 95921(a)(1)(E) and 95921(a)(3)(B) to (D) should be deleted.

For the purposes of comparison, the provisions in the Quebec “Regulation respecting a cap-and-trade system for greenhouse gas emission allowances” on emission allowance transactions contain only a requirement to complete a transfer within three days of the start of the transfer process, similar to section 95921(a)(3)(A) of California’s Regulation. There are no transfer deadlines that relate to the underlying transaction agreement.

B. If section 95921(a)(1)(E) is not deleted, change the term “settlement date.”

If these sections must be retained, they require several amendments. Section 95921(a)(1)(E) currently refers to the “settlement date.” However, not all agreements have a defined settlement date. Furthermore, agreements for multiple transfers of compliance instruments over time will have multiple dates by which transfers must be made, and none of these may be referred to as “settlement dates.” In the rationale for the proposed changes to section 95921(a)(3)(B), the ISOR notes that the term “settlement date” is unclear in relation to certain types of agreements. For these reasons, the term “settlement date” should be avoided in section 95921(a)(1)(E) also.

C. Section 95921(a)(3)(C) is unnecessarily restrictive.

Section 95921(a)(3)(C) is particularly problematic. It prohibits transfers of compliance instruments more than three days after the transfer of consideration under the agreement. The meaning of “consideration” is unclear, but assuming it refers to payment for the compliance instruments, this provision prohibits all types of down payments, advance payments, deposits or early lump sum payments. This unnecessarily restricts the ability of contracting parties to enter into agreements that suit them.

For bundled transactions, e.g. those that transfer allowances and electricity for a bundled price, this provision would also prohibit the parties from agreeing a payment schedule that matches the schedule for delivery of electricity. The parties must instead agree a payment schedule that matches the transfer of allowances, which may be on a very different timeframe from the delivery of electricity. For example, electricity may be required in particular seasons or times of day due to load considerations, whereas the parties may agree to transfer allowances a month before the annual compliance deadlines. The application of section 95921(a)(3)(C) to agreements that do not provide a price for the compliance instruments (such as the types of agreements listed in section 95921(b)(6)) is also unclear.

In the rationale for section 95921(a)(3)(C), the ISOR states that payments need to be immediately followed by the transfer of compliance instruments to avoid creating the type of “holding on behalf” that is prohibited under section 95921(f)(1). This section provides that:

> An entity cannot acquire allowances and hold them in its own holding account on behalf of another entity Including [sic] the following restrictions:
>
> (A) An entity may not hold allowances in which a second entity has any ownership or financial interest.
>
> (B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments reside in the first entity’s accounts, or control over the acquisition of allowances by the first entity. These prohibitions do not apply to agreements that only specify a date to deliver a specified quantity of allowances and that include no terms applying to allowances residing in another entity’s account. ...

However, if Entity A transfers compliance instruments to Entity B more than three days after Entity B paid for them, this would not give Entity B any ownership interest in, or control over, the compliance instruments in Entity A’s account. Entity B only has a contractual right to receive the compliance instruments by the dates specified in the agreement. If Entity A does not transfer the instruments on time, Entity B could pursue the remedies provided in the agreement, for example liquidated damages.

Furthermore, given that section 95921(f)(1) exists, there is no need to include other provisions that seek to prohibit situations that are already prohibited (with the appropriate caveats) under section 95921(f)(1).

For these reasons, section 95921(a)(3)(C) must be deleted, even if the other subsections of section 95921(a)(3) are retained.

D. If section 95921(a)(3) is not deleted, it should be revised for clarity and the deadlines should be reconsidered.

Section 95921(a)(3) should be redrafted for clarity – presumably it means penalties may apply if transfers are not completed within three days of the earliest to occur of events (A)-(D). However, a period of three days is not appropriate in all cases. Furthermore, the termination date mentioned in (B) should be a separate subsection. It is listed apparently as an alternative to the "execution date", but it bears no relationship to that date. As noted in section II.A above, the term "execution date" should be changed to "agreement transfer date," as "execution date" is easily confused with the date on which the parties signed the agreement. This term may be appropriate for section 95921(a)(1)(E) also, in place of the unclear "day of settlement."

For these reasons, sections 95921(a)(1)(E) and (a)(3) of the Regulation should revised as follows, if they cannot be deleted entirely:

> **Recommendation:** (1)(E) The completed transfer request must be received by the accounts administrator no more than 30~~three~~ days following the agreement transfer date~~day of settlement~~ of the transaction agreement for which the transfer request is submitted. ...
>
> (3) The parties to a transfer will be in violation and penalties may apply unless~~if~~ the above process is completed by the earliest to occur of the following dates:
>
> > (A) ~~More than t~~Three business days after the initial submission of the transfer request; or
> >
> > (B) ~~More than three~~Thirty days after the agreement transfer~~execution~~ date ~~or termination date~~ of the transaction agreement for which the transfer request is submitted; or
> >
> > (C) Thirty days after the termination date of the transaction agreement for which the transfer request is submitted~~More than three days after the transfer of consideration from the purchaser of the compliance instrument to the seller as provided by the transaction agreement~~; or

(D) ~~More than three~~ Fifteen days after the execution of the underlying trade on an exchange or other trading platform. (SCPPA 1)

Comment: Section 95921(a)(3) (C): New Section 95921(a)(3)(C) specifies that parties to a transfer will be in violation if the transfer process is completed more than three days after transfer of consideration from the purchaser of the compliance instrument. CPEM believes this standard is unworkable. The transfer process itself can take three days. Requiring the process to be completed prior to that time essentially means that the process must be started prior to payment for the instruments to ensure no violation would occur – a commercially unreasonable outcome. Counterparties often agree that payment must be made sufficiently prior to delivery to insure that all monies have cleared. Commercially, there should be no reason why a party can not pay in advance a fixed price for carbon instruments that will delivered over the course of time. Such a transaction could lower costs for all parties by avoiding concerns about payment risks, the need to hold alternative security, etc. CPEM submits that, if a time window is included, it should be based on the time the transfer is initiated, not completed.

With respect to both Section 95921(a)(3)(B) and Section 95921(a)(3)(C), CPEM expressly requests, that, in the event these proposed changes are not deleted, the ARB clarify that parties to an existing transaction will not be penalized (or otherwise be held in violation) to the extent they act in good faith under the terms of agreements that existed prior to the effective date of this proposed rule. For example, the ARB should clarify that a party to an existing transaction that calls for payment to be made seven days prior to delivery of compliance instruments will not be subject to penalty. (CPM 1)

Response: The basic requirement that the transfer request process be completed within three days of the settlement of the underlying transaction agreement is part of the existing regulation and ARB is proposing to maintain that language for the remainder of 2014, and use “expected termination date” beginning in 2015. This 15-day change is in response to the various interpretations that can be made to the term “settlement.” Staff does not believe this basic requirement unduly restricts transactions but instead assures prompt reporting of trades to ARB. Staff believes this change makes unnecessary the clarification proposed in the comment on section 95921(a)(1)(E).

Moreover, staff has removed the proposed language in section 95921(a)(3)(C) as staff was unable to resolve issues with the definition of transfer of consideration. Staff also removed section 95921(a)(3)(D), which was made unnecessary by the replacement of “settlement date” by “expected termination date” in 95921(a)(3)(B).

H-3.12. Comment: §95921(a)(1). Transfers of compliance instruments between accounts: The process of transferring compliance instruments between accounts is required to be completed within three days. Therefore, if the initiation of the transfer begins on a Thursday, the transfer process must be complete by Sunday. The primary account representative (PAR) or alternate account representative (AAR) for the same entity must, in addition to submitting the transfer request, confirm the request to GARB's accounts administrator within two days of the initial transfer request. The PAR or AAR for the destination account must confirm the transfer request to GARB's accounts administrator within the time remaining in the three days following the initial transfer request. Therefore, in this case, the PAR/AAR of the source account and/or the PAR/AAR of the destination account must make their confirmations during the weekend. LADWP is requesting that compliance instrument transfers be required to be completed during business days.

§95921(a)(3)(D). Transfers of compliance instruments between accounts: §95921(a)(3) describes the time frames for which entities would be required to complete compliance instrument transactions in the Compliance Instrument Tracking System Services. With respect to §95921(a)(3)(D), parties to a transfer will be in violation if the compliance instrument transfer is completed more than three days after the execution of the underlying trade on an exchange or other trading platform. Completion of transfer of funds (e.g. wire transfer) and the GARB's transaction approval process within a three calendar day period for trades done on an exchange would not be possible for LADWP due to its internal financial approval processes. In the case of electricity transactions, the transactions can be completed and financially settled on the twentieth day of the month in which the invoice was received or the tenth day after the receipt of the bill, whichever is later, per Western Systems Power Pool Guidelines. LADWP questions the importance of controlling the timing of the settlement of a compliance instrument transaction done on an exchange. Entities should have the flexibility to develop the terms of their compliance instrument transaction as long as the compliance instrument transfer process is completed in a reasonable manner. Thus, LADWP recommends that proposed §95921(a)(3)(D) be deleted. (LADWP 1)

> **Response:** ARB staff disagree with the comment's description of the time needed for completing the transfer request process under section 95921(a)(1). The comment correctly illustrates the maximum time the account representatives could take to complete the process, but not the actual time needed. It is ARB's understanding, based on discussions with account representatives, that the process of entering information into CITSS and confirming takes minutes. Since neither party ought to be surprised that the transaction is occurring, there is no reason why the representatives cannot coordinate the timing of the transfer request to avoid the problem described in the comment.
>
> The comment on section 95921(a)(3)(D) is moot because ARB removed that provision through the 15-day amendments.

H-3.13. Comment: The proposed language in section 95921(a)(3)(D) makes it a violation to transfer compliance instruments on CITSS later than 3 days after the purchaser has paid for the transaction. IETA wonders why ARB feels the need to prescribe rules for this transaction process. We do not see why flexibility cannot lie with entities on this matter. (IETA 1)

Response: The comment on section 95921(a)(3)(D) is moot because ARB removed that provision through the 15-day amendments.

H-3.14. Comment: Section 95921. Prohibitions on Trading: 1. ARB Should Not Impose Unreasonable Transfer Requirements Because The Current Regulation Provides Significant Transparency. PG&E opposes ARB's proposed amendments to Section 95921(b)(3) which impose penalties on parties to a contract involving a transfer of compliance instruments if the compliance instrument transfer occurs more than three days after the execution date or te1mination date of the transaction agreement, or more than three days from the date of "transfer of consideration from the purchaser of the compliance instrument to the seller." Parties to contracts involving compliance instruments should be free to structure transfers of allowances and payments in a manner appropriate to the underlying transaction.

ARB's Proposed Regulation unreasonably prohibit certain commercial structures. PG&E understands ARB's underlying concern of preventing fraud and/or market manipulation. However, ARB incorrectly assumes that the transfer of compliance instruments between parties at a particular time suffices as intent to manipulate the compliance instrument market. This is just not the case. PG&E is concerned that the proposed rules will have the unintended consequence of unduly complicating transactional structures for compliance instruments, resulting in increased costs of compliance. Moreover, PG&E questions ARB's need to prohibit certain transactional provisions given the current robust suite of market monitoring tools provided in Section 95921.

In addition, ARB's proposal is too vague to be effectively implemented. For example, the transfer of allowances more than three days from the transfer of "consideration" is prohibited. Consideration can include any exchange of value and can be in the form of money, goods, services, commodities or other promises or forbearances. Requirements for the transfer of compliance instruments based on any exchange of any form of consideration is simply infeasible. The proposed regulation would restrict parties from structuring transactions to include provisions including advance payments, letters of credit, guarantees, and other forms of consideration which will only serve to increase the cost and the complexity of compliance with the Cap-and-Trade program and will not provide for additional transparency or market monitoring.

Furthermore, proposed revisions to Section 95921 (a)(3)(B) should be rejected because they conflict with existing and proposed modifications to Section 95921. Existing Section 95921 (a)(1)(E) requires completed transfer requests to be received by the administrator no more than three days following the date of settlement of the transaction agreement. This provision conflicts with Proposed Section 95921 (a)(3)(B) which imposes penalties if allowance transfers are completed three days after the execution date. Section 95921 (a)(3)(B) also conflicts with Proposed Section 95921 (b)(2)(B) and Proposed Section 95921 (b)(4) because those provisions contemplate over-the-counter agreements with delivery taking place more than three days from the date the parties enter into the transaction agreement. The consistency and clarity of ARB's requirements is critical for parties to structure their compliance instrument transfers and related transactions and comply with the Regulation.

Existing Section 95921 provides ARB with significant market transparency, allowing the agency to see and approve the transfer of the compliance instruments and track each compliance instrument transaction. For example, Section 92921 (a)(E) establishes a process that requires compliance instrument transfers to be completed following three days of a settlement of the transaction agreement. Existing Section 95921 (b) requires parties to the transfer request provide substantial information about the transaction agreement. In addition, ARB's proposed revisions to Section 95921 (b) will provide ARB with a vast amount of information concerning the transactions, including the original and destination accounts, the type, quantity and vintage of compliance instruments, the type of transaction agreement, the delivery structure, and other commercially sensitive data concerning the underlying, including price of the underling compliance instrument and any ancillary product.

If the restrictive provisions are upheld, ARB should explicitly exempt the application of Section 95921 (a)(3)(B) and (C) to those agreements that are exempt from the prohibitions on holding allowances on behalf of other entities. The ISOR explains that Section 95921 (a)(3)(C) was added to comport with restrictions of holding allowances on behalf of other entities. While PG&E does not agree that conveyance of forms of consideration necessarily create an interest in one entity's compliance instruments on behalf of another, at a minimum the regulation should not apply to those transactions exempted from holding restrictions. Specifically, PG&E proposes the following modification to Section 95921 (a)(3)(C):

> (C) More than three days after the transfer of consideration from the purchaser of the compliance instrument to the seller as provided by the transaction agreement, <u>provided that this prohibition does not apply to transactions described in Section 9592lffi(l)(B);</u> or (PGE 2)

> **Response:** The comments on sections 95921(a)(1)(E) and (a)(3)(C) are moot as ARB has removed those sections in the 15-day amendments. Staff disagrees with the assertion that there is a conflict between the originally proposed section 95921(a)(3)(B) and proposed sections 95921(b)(2)(B) and 95921(b)(4). The former addresses when the transfer request must be submitted relative to the “execution date” of the transaction agreement, which has been replace by the “expected termination date” of the transaction agreement. The latter refers to the timing for delivery on an agreement relative to when the agreement was entered into. ARB sees no inconsistency between these provisions. The purpose of section 95921(b)(2)(B) is to allow the account representative to determine the information to be added to transfers occurring more than three days from the date on which the parties entered into a transaction agreement. It makes no reference to when the transfer request is actually submitted.

H-3.15. Comment: TID is particularly concerned with new restrictions on allowance transfers, which are specified in the proposed amendments to Section 95921(b)(3). These amendments would impose penalties on parties if the actual transfer of compliance instruments occurs after the three day period for review and approval by the Executive Officer. Section 95921(b)(3) would also penalize transfers of consideration that occur before the three day review and approval process by the Executive Officer. These amendments to Section 95921(b)(3) would unreasonably prohibit a broad array of commercial structures. Consideration is a legal term that can include any exchange of value and can be in the form of money, goods, services, commodities or other promises or forbearances. As amended Section 95921(b)(3) would restrict parties from structuring transactions to include provisions including advance payments, letters of credit, guarantees, and other forms of consideration. This amendment would increase the cost and the complexity of compliance with the Cap-and-Trade program and will not provide for additional transparency or market monitoring.

Turlock Irrigation District proposed revisions to September 4, 2013 Cap-And-Trade Regulation: Do not revise Section 95921(b). (TID 1)

> **Response:** The comment appears directed at section 95921(b)(3)(C) or (D), both of which have been removed as part of the 15-day changes. As such, the commenter's concerns for these sections are moot.

H-3.16. Comments: Minimize additional data on compliance instrument transactions and clarify how ARB will use this data: The proposed revisions to section 95921(b) of the Regulation require entities to provide more information on compliance instrument transactions when requesting transfers of compliance instruments in the tracking system, particularly for customized bilateral transactions and exchange-traded contracts.

For customized bilateral agreements, the additional information includes:

- If the contract contains provisions for further compliance instrument transfers, the transfer frequency (e.g. quarterly);
- If the contract is a "bundled" purchase of instruments and other products, the products, for example, natural gas; and
- How the price is determined, for example, fixed price or base plus margin.

For exchange-traded contracts, the additional information includes:

- Name of exchange and exchange code;
- Type of contract (spot, future);
- Date of close of trading for the contract; and
- Price at close of trading.

ARB staff members have stated that this information is required for market monitoring purposes. However, the extent to which the ARB can or should regulate the secondary market in allowances and offsets is debatable. Other agencies that currently monitor commodities and financial markets will have jurisdiction over this market and have the tools and expertise to monitor it.

The ARB should clearly state how it intends to analyze the data reported under section 95921(b) and provide assurances as to the confidentiality of this data. Transaction information is commercially sensitive, and the ARB must ensure that if it provides any transaction data to the market, the data is aggregated so that it cannot be traced to individual entities. (SCPPA 1)

> **Response:** The comment is incorrect in its assertion that "…agencies that currently monitor commodities and financial markets will have jurisdiction over this market…" Compliance instruments are not regulated as securities and agencies monitoring those markets are not necessarily monitoring the California Cap-and-Trade market. The U.S. Commodity Futures Trading Commission (CFTC) does monitor trading of futures and options contracts based on California Compliance instruments, but the CFTC does not routinely monitor other transactions resulting in the transfer of compliance instruments, collect data on those transfers, or provide the data it does collect to ARB. ARB is the sole entity maintaining the record of compliance instruments holdings and as such has the ability and authority to create and enforce the rules governing transfers. The data requirements are necessary for this activity and only complement market data gathered by other enforcement agencies.
>
> The comments that ARB must (1) provide assurances on the confidentiality of the data and (2) ensure data releases are aggregated are outside the scope of the proposed amendments as they are addressed in existing section 95921(e), which has not been modified as part of this rulemaking. Existing text in this section also answers the comment requesting an explanation of the use ARB will make of the data, as it requires the release of transfer prices and quantities. As ARB has explained during previous rulemakings, release of market information is needed to ensure market transparency.

H-3.17. Comment: Information required for compliance instrument transfer requests: WPTF remains concerned about the proposed expanded information requirement for compliance instrument transfers in the CITSS proposed in section 95921(b)(2). These new information requirements would impose significant burdens on entities to have to unwind many complex and varied compliance instrument transactions in order to accurately provide price and transaction type information. The additional requirements also increase the risk of an entity inadvertently entering inaccurate information, which could result in rejection of a transfer request and/or the imposition of financial penalties by CARB. These additional administrative burdens and increased risks are not insignificant, and will ultimately raise program compliance costs for covered entities.

CARB's regulations also lack clarity as to how CARB intends to use information that it collects on price and transaction type. One explanation provided at the July 18th workshop was that CARB only wants to be able to understand the secondary market. However, CARB's proposed regulation would allow it to audit these transactions, which raises concern that CARB may also claim the right to opine on the appropriateness of individual compliance instrument transactions and associated price. This concern could drive many market intermediaries (voluntary entities) out of the market and reduce liquidity, if there is an indication that such prices could be subject to review and/or disallowance of some sort.

WPTF is also concerned that the ARB has begun to systematically collect contracts for allowance transactions. It is unclear why the ARB is collecting this information, what the ARB is doing to protect the information in these contracts, or how it furthers the ARB's role as a market monitor. Nor is it clear that collecting these contracts is permitted under the ARB's statutory or regulatory authority under AB 32.

WPTF's strong preference is to retain the existing transaction information requirements rather than the proposed amendments. If CARB retains the expanded information requirements, we request that staff provide a clear explanation of how information collected will be utilized, why the collection of this information is necessary and how confidentiality will be maintained. (WPTF 1)

> **Response:** The comment does not make clear what types of transactions would have to be "unwound" due to the proposed requirements. Staff is assuming that the comment refers to transaction agreements with complicated terms that may not specify a price, such as transfers of multiple products. As part of the proposed 15-day changes ARB has added new section 95921(c)(6) which contains seven instances in which the account representatives will not have to enter a price. This list covers a number of complicated types of transaction agreements that ARB has observed. Staff believes these exemptions would prevent the "unwinding" described in the comment.
>
> Staff is also confused by the assertion that ARB seeks to act "on the appropriateness of individual compliance instrument transactions and associated price." Staff is not aware of any provisions in the proposed regulation that would result in "disallowance of some sort" as described by the commenter. There are holding limits and rules against fraud or manipulative behavior in the existing regulation, but the proposed text only contains provisions that provides account representatives with a clearer path to providing the transaction data already required by the regulation. The basic requirement to report price, quantity and timing already exists. The proposed regulation only seeks more detail for more complicated transactions where it may be difficult to fill in the fields now included in CITSS.
>
> ARB has statutory authority to collect documentation to ensure compliance. Existing section 95921(b) contains an additional provision requiring parties to a transfer to provide documentation on the underlying transaction. New section 95921(c) merely repeats the requirement for the reporting requirements that are

in effect from July 1, 2014 through December 31, 2014. As for how ARB treats confidential business information, existing section 95921(e) defines which information ARB will treat as confidential. ARB has extensive experience handling confidential business information along with the legal processes needed to protect that information.

H-3.18. Comment: Sections 95921(b)(3)(A) and 95921(b)(4)(A)(B): Requires dates that an over-the-counter agreement was entered and terminated, and transfer schedule. The information has no bearing on the integrity of the trading process.

Recommendation: Delete these requirements. (WSPA 1)

Response: Sections 95921(b)(3)(A) and (b)(4)(A) contain an existing requirement to report the date on which entities enter into a transaction agreement. The change is only needed to accommodate the reorganization of the section. The requirement allows ARB to interpret the price based on when the price was determined. For example, if the transaction agreement is a one-year forward contract at a fixed price, the price will be based on market conditions and parties' expectations from the year earlier. Since ARB only learns of the price at the time of delivery the price may appear as an outlier. Some standard market monitoring techniques involve looking for price data anomalies. If staff did not have access to information on the agreement date then there would be an unnecessary expenditure of staff and account representative time as the outlier is investigated.

Section 95921(b)(4)(B) is also needed for monitoring and enforcement purposes. The expected termination date alerts monitoring staff to the existence of additional terms that may have a bearing on the interpretation of the reported price. In addition, the field allows staff to enforce the requirement that the transfer request process be completed within three days of the termination date. Therefore, staff declines to make the suggested deletions.

H-3.19. Comment: Sections 95921(b)(3)(C), 95921(b)(4)(D)(E)(F)(G) and 95921(b)(5)(E): Requires the price of compliance instrument, transfers of products, and the pricing method. The auctions' settlement price and the reserve auctions are the best indicators for price containment. Reporting of over-the-counter price to CITSS will not provide added value to the market.

Recommendation: Delete this requirement. (WSPA 1)

Response: The comment objects to a price disclosure requirement which is contained in the existing requirements in section 95921(b)(6). The argument that auction results are sufficient indicators of price containment is incorrect. If markets become tight after, for example, the last auction of a compliance period, the prices reported as part of the transfer requests will be the only reliable indicator of market conditions. There are few regular market reports of over-the-counter trades and the market has no way to evaluate their reliability and coverage. Failing to require price disclosure would limit ARB's ability to detect market problems or enforce market rules. Therefore, ARB staff declines to delete the requirement.

H-3.20. Comment: Section 95921(b)(4)(C), page 198: ARB has proposed language: If the transaction agreement provides for further compliance instrument transfers after the current transfer request is approved, specify the scheduled frequency as monthly, quarterly, annual, or unspecified." ARB does not need this information. (WSPA 1)

Response: ARB staff has modified the proposed language through 15-day changes to eliminate the requirement that the account representatives add the frequency of the transfers. The revised language only requires the representative to indicate whether the agreement provides for subsequent transfers. This removes the burden of entering additional information while enabling staff to still understand the nature of the agreement.

H-3.21. Comment: Sections 95921(b)(2)-(5) are asking for too much information about transactions. Section (4)(C), in particular, highlights this in that an entity is already required to report a transaction within three days after the settlement date, that is, the date of payment and transfer of allowances to the purchaser. If an entity makes an agreement to purchase allowances from another entity every quarter, the purchaser should only have to report the allowances it has actually paid for and received each quarter.

Recommendation: Delete this requirement. (WSPA 1)

Response: Section 95921(4)(C) has been modified in the 15-day amendments so that the account representative only reports the quantity transferred under the transfer request and flags the existence of subsequent transfers. The requirement to report frequency is dropped.

Sections 95921(b)(2)-(5) have been added to replace the "one size fits all" approach with information requirements that match the specific type of agreement involved. The language is based on staff reviews of transfer agreements and conversations with a number of account representatives. Most account representatives will not have to enter additional information over what is currently incorporated into CITSS. The only significant change is to price reporting for the very small number of contracts that have price determined by some type of market index (such as auction settlement price) plus a margin.

H-3.22. Comment: Sections 95921(b)(5)(C) and (D): Requires the date of close of trading for the contract and identification of the contract as spot or future. Entering the information for Exchange-Based Agreement is unnecessary because ARB can obtain the information from the exchange.

Recommendation: Delete this requirement. (WSPA 1)

Response: Staff has removed the proposed requirement to identify the contract as futures or option as part of the 15-day changes. Staff has retained the other requirements because ARB would not be able to match exchange data with transfers unless the account representative provides sufficient information to allow staff to identify the contract involved. This is necessary for effective market monitoring.

H-3.23. Comment: Section 95921(b)(6)(F): The use of the term "bundles" in Section 95921(b)(6)(F) may be misleading. It implies that the products flow together, whereas an entity's obligation and the products from the manufacturing partner are flowing in opposite directions. Additionally, the term "transaction agreement" was added in several places without a definition. The term "agreement" is commonly used and most entities do not use the term "transaction agreement" in their businesses.

Recommendation: Reword the paragraph as follows:

(b)(6)(F) The proposed transfer results from a<u>n</u> ~~transaction~~ agreement that ~~bundles~~ ~~compliance instruments~~ <u>incorporates compliance instrument requirements with other product</u> <u>sale or purchase,</u> and does not specify a price or cost basis for the sale or purchase of compliance instruments alone. (WSPA 1)

Response: ARB staff agrees with the comment and has made the relevant change in 15-day changes.

H-3.24. Multiple Comments: Section 95921(b)(3)(B): New Section 95921(b)(3)(B) requires that a transfer request for an over the counter agreement include a "Date of settlement," and notes that, if there are financial or other terms to be settled after the transfer request is approved, the date those terms are to be settled should be entered as the settlement date. The ARB should recognize that many terms to be settled may be subject to floating dates or dates triggered by other events. As such, ARB should clarify that, if the settlement date is not fixed in the contract, an estimated settlement date may be provided, without subjecting the reporting entity to liability if the date changes.

Section 95921(b)(4)(D): New Section 95921(b)(4)(D) requires that, if a transaction agreement provides for transfers of other "products" such products must be specified. ARB should clarify the definition of "products." (CPM 1)

Comment: Section 95921(b)(3)(B): This new section requires that a transfer request for an Over-The-Counter (OTC) agreement include a "date of settlement," and notes that, if there are financial or other terms to be settled after the transfer request is approved, the date those terms are to be settled should be entered as the settlement date.

IETA would like to point out that many terms to be settled may be subject to floating dates or dates triggered by other events. We recommend that if the settlement date is not fixed in the contract, ARB should allow an estimated settlement date to be provided without subjecting the reporting entity to liability if the date changes. (IETA 1)

> **Response:** Staff appreciates the concerns expressed in the comments. Staff has modified the proposed language as part of the 15-day amendments to explicitly address the types of provisions identified in the comment, including defining the relevant date as “expected.” Staff believes that in practice there will be no problems entering a termination date because either (1) the terms to be settled after the transfer is completed will have a date that can be used as the Expected Termination Date, or (2) the entity may enter the Date as “Not Specified.”
>
> Staff disagrees with the need for a definition of “products” as the term is used consistently with its common English usage.

H-3.25. Comment: proposed contract information submission requirements: SGEN appreciates the efforts ARB intends to undertake to tailor CITSS to account for all possible transfers that could potentially occur in an entity's account, but the proposed amendments to section 95921(b) are unnecessary and overly burdensome. These proposed amendments would require entities to provide information regarding transactions with an unreasonable level of detail given the very limited timeframe allowed between the "execution date" and date which the transfer must be reviewed and approved by all involved parties. This short timeframe puts transferring entities at risk of either missing a transaction completion deadline, or providing ARB inaccurate details of a transaction which could be potentially viewed as false or misleading, and therefore a violation of 95921(e)(2)(D).

The proposed amendments to section 95921(b) should be removed from consideration at this time to allow for ARB to work with market participants to determine what information would be most useful to ARB, while not putting an entity at risk of inadvertent non-compliance with the Regulations due to the limited timeframes inherent with these transactions. In addition, aside from the burdensome and confusing data entry requirement proposed, subsection (b)(3) has added the term "execution date" and removed the reference to "settlement day." These terms appear to be used in a context that is not entirely consistent with the context commonly used by entities when entering into these types of transactions and may add to the overall confusion with the proposed amendments to section 95921(b). (SEMPRA 1)

> **Response:** Staff disagrees with the assertion made in the comment that the level of detail of information to be submitted with a transfer request is unreasonable “given the very limited timeframe in which all involved parties must review and approve a transfer.” Very few account representatives will observe a significant change in the amount of information they must enter. Most account

representatives will see fields in CITSS that more closely match the type of information they must submit.

ARB staff has removed the proposed requirement that the account representatives enter an “execution date.” Staff was unable to resolve the many different interpretations stakeholders place on that term. Instead, staff proposes to retain the term “expected settlement date” until January 1, 2015, when CITSS can be updated to use the term “expected termination date.”

H-3.26. Comment: Section 95921(b)(2) requires a minor amendment for consistency: Section 95921(b)(2)(B) refers to transaction agreements involving “multiple transfers of allowances over time for the bundled sale of allowances with other products” (emphasis added). The word “for” is restrictive, as only agreements that were for bundled products with multiple transfers over time would qualify. The Magnolia Transaction Agreement would not qualify under this provision, nor would it qualify under sections 95921(b)(2)(A) or (C), because it is an agreement with multiple transfers over time, but only for compliance instruments, not bundled products.

The word “for” in section 95921(b)(2)(B) is inconsistent with the ISOR and with a later section of the Regulation relating to the same type of transaction agreement.

The summary of section 95921(b)(2)(B) in the ISOR refers to “over the counter agreements for which delivery will take place more than three days from the date the parties enter into the transaction agreement or that involves multiple transfers of instruments over time or the bundled sale of instruments with other products” (emphasis added). This approach is preferable because it does not unduly restrict the scope of the second type of transaction agreement.

Section 95921(b)(4), following the approach of the ISOR, refers to agreements that involve “multiple transfers of allowances over time or the bundled sale of allowances with other products” (emphasis added).

For consistency and to avoid unduly restricting the scope of the second type of transaction agreement, section 95921(b)(2)(B) should be revised to match the ISOR and section 95921(b)(4) by replacing the word “for” with the word “or.”

Recommendation: The Magnolia POUs’ proposed change to section 95921(b)(2)(B) is set out below:

(B) Over-the-counter agreement for the sale of compliance instruments for which delivery is to take place more than three days from the date the parties enter into the transaction agreement or that involve multiple transfers of compliance instruments over time or~~for~~ the bundled sale of compliance instruments with other products. (SCPPA 2)

Response: Staff agrees with the comment and has made the appropriate change.

H-3.27. Multiple Comments: Section 95921(b)(4) requires some amendments to allow for complex agreements: Some revisions to sections 95921(b)(4)(B) and (C) to allow for simplified reporting of the potentially complex details of transaction agreements would be helpful.

Section 95921(b)(4)(B) requires a transfer request to include the date the transaction agreement terminates. However, a transaction agreement may not provide for a single, simple termination date. The date of termination may depend on a range of circumstances and conditions, or obligations may terminate at different times for different parties. Complex termination provisions cannot be reported simply. Conversely, reporting complex termination provisions in full would be time-consuming for the reporting entity, and it would also be time- consuming for the ARB staff to analyze the report. Accordingly, if transaction agreements have complex termination provisions, the parties should be allowed to report the termination date under section 95921(b)(4)(B) as "other."

Section 95921(b)(4)(C) requires transfer frequency to be reported as "monthly, quarterly, annual, or unspecified." However, a transaction agreement may require compliance instruments to be transferred by specified dates that are neither monthly, quarterly, nor annually. To more accurately reflect transaction agreements that contain specified but irregular transfer dates, the option to report the transfer frequency as "other" should be added to section 95921(b)(4)(C).

Recommendation: The Magnolia POUs' proposed changes to section 95921(b)(4) are set out below:

(4) A transfer request submitted for an over-the-counter agreement for the sale of compliance instruments for which delivery is to take place more than three days from the date the parties enter into the transaction agreement or that involves multiple transfers of compliance instruments over time or the bundled sale of compliance instruments with other products must provide the following information: …

(B) Date the transaction agreement terminates. <u>If the transaction agreement does not specify a particular calendar date as the termination date, report the termination date as "other."</u>

(C) If the transaction agreement provides for further compliance instrument transfers after the current transfer request is approved, specify the scheduled frequency as monthly, quarterly, annual, ~~or~~ unspecified<u>, or other</u>. … (SCPPA 2)

Comment: New Section 95921(b)(4)(B) requires that a transfer request for an over the counter agreement with delivery to take place in the future include a "date the transaction agreement terminates." As with the date of settlement discussed above, termination dates are often not fixed, and the agreement may extend until all parties have performed their obligations. As such, ARB should clarify that, if the termination date is not fixed in the contract, an estimated termination date may be provided without subjecting the reporting entity to liability if the date changes.

New Section 95921(b)(4)(C) requires that, if a transaction agreement provides for further compliance instruments transfers, the transfer request must specify whether the transfers are monthly, quarterly, annual or unspecified. ARB should clarify that a transfer request may indicate "unspecified" for transactions with other specified terms (such as biannual or biennial) without violating the regulations. (CPM 1)

Comment: Section 95921(b)(4)(B): This new section requires that a transfer request for an OTC agreement with delivery to take place in the future include a date upon which the transaction agreement terminates.

Similarly to the settlement date issue outlined above, termination dates are often not fixed, and the agreement may extend until all parties have fulfilled their obligations. IETA recommends that ARB include language clarifying that if the termination date is not fixed in the contract, an estimated termination date may be provided without subjecting the reporting entity to liability if the date changes. (IETA 1)

> **Response:** Staff agrees with the concerns expressed in the comments. As part of the 15-day changes, staff has modified proposed section 95921(b)(4)(B) to change the term to "expected termination date," and to add an explanation of how the account representative should deal with unspecified dates.
>
> Staff modified section 95921(b)(4)(C) to only require the account representative to indicate whether or not the transaction agreement requires subsequent transfers. The requirement to specify a frequency has been deleted.

H-3.28. Comment: Section 95921(b)(6)(c) should be amended to allow for the Magnolia circumstances: Section 95921(b)(6) allows for a price of zero to be reported for compliance instrument transfers in certain circumstances. The Magnolia POUs would like to rely on this section to report transfers under the Magnolia Transaction Agreement at a price of zero, because BWP will not be paying the other Magnolia POUs for the compliance instruments that they will be required to transfer to BWP under the Magnolia Transaction Agreement.

Section 95921(b)(6)(C) comes close to covering the Magnolia situation. It allows a price of zero to be reported if:

The proposed transfer is from a publicly-owned utility to an entity or a Joint Powers Authority operating a generation facility as a joint venture with the utility.

However, BWP does not operate Magnolia as a joint venture with the other Magnolia POUs. BWP operates Magnolia as an operating agent under a Construction, Management, and Operating Agreement with SCPPA as the owner of Magnolia. The Magnolia POUs are the members of SCPPA that participate in Magnolia.

It does not appear that the Magnolia Transaction Agreement would fall under any of the other zero price transfers set out in sections 95921(b)(6)(A), (B), (D), (E), or (F). Therefore, the Magnolia POUs propose that section 95921(b)(6)(C) be revised, or an additional subsection (G) be added, to allow for transfers at a price of zero in the Magnolia situation.

Recommendation: The Magnolia POUs' proposed changes to section 95921(b)(6)(C) are set out below:

(C) The proposed transfer is from a publicly-owned utility to an entity (including~~or~~ a Joint Powers Authority of which that utility is a member, or an operating agent acting on behalf of such a Joint Powers Authority) operating a generation facility ~~as a joint venture with~~from which the utility procures electricity. (SCPPA 2)

Response: Staff agrees with the concern expressed in the comment. However, the existing text does apply to other entities. Staff therefore has added section 95921(b)(6)(G) to incorporate the text proposed in the comment.

H-3.29. Comment: Proposed Definitions of Transfers/Transactions: Four new definitions pertaining to the possible transfers that could potentially occur in an entity's account have been proposed under 95802(a): "Execution Date," "Futures," "Spot" and "Over-the-Counter."

Recommendation: As noted above, the proposed language in section 95921(b) should be removed, but if the new language proposed for section 95921(b) is not removed, the following amendments are recommended in order to be more consistent with the definition these terms have in other markets:

Section 95802(a)(130): "~~Execution~~ Delivery Date" means a provision of a transaction agreement that requires the transfer of compliance instruments on or before a date specified in the agreement.

Section 95802(a)(153) "Futures" means an agreement to purchase or sell a commodity for delivery in the future: (1) at a price that is determined at the initiation of the contract; (2) that obligates each party to fulfill the contracts at a specified price; ~~(3) that is used to assume or shift price risk; and (4) that may be satisfied by delivery or offset.~~

Section 95802(a)(244) "Over-the-Counter" means the <u>purchase or sale of a commodity</u> ~~trading of carbon compliance instruments, contracts, or other instruments~~ not listed on any exchange.

In addition, the following definitions should be added for consistency:

"Settlement Date" means the date in which the price for the transaction was determined.

"Execution Date" means the date the parties entered into 'the underlying agreement of which a transaction is based. (SEMPRA 1)

Response: The comments on definitions (130) “Execution date,” and (153) “Futures” are moot because ARB staff has proposed to remove these terms from the proposed regulation as part of the 15-day amendments, so the definitions are no longer needed. Staff agrees with the comment that definition (244) “Over the Counter” needs clarification, but does not agree with the recommended revision. Instead, staff concluded that a suggested revision contained in another comment better corrected the lack of clarity in the definition. The definition therefore now reads: “Over-the-Counter” means the trading of carbon compliance instruments, contracts, or other instruments not executed or entered for clearing on any exchange.

H-3.30. Multiple Comments: §95802(130) Definition of Execution Date: The proposed amendments define "Execution Date" as "a provision of a transaction agreement that requires the transfer of compliance instruments on or before a date specified in the agreement."

The term "Execution Date" is used in §95921(a)(3)(A) to prescribe the process of transferring compliance instruments between entity accounts: "The parties to a transfer will be in violation and penalties may apply if the above process is completed: ... (B) More than three days after the execution date [emphasis added] or termination date of the transaction agreement... " The term "Execution Date" in itself can cause confusion, as it would imply the date that the transaction is agreed upon, not the date of compliance instrument transfer.

Furthermore, Sections 95921(a)(1)(E) and 95921(a)(3)(C) refer to the "day of settlement of the transaction agreement" or a date "as provided by the transaction agreement." In addition, the terms "settlement" and "termination date (§95921(a)(3)(B))" are undefined. The use of multiple phrases which appear to have the same meaning and that contain undefined terms could create confusion for compliance entities. In the energy markets, "execution date" may be different from the "settlement date." For consistency and to avoid confusion, LADWP recommends that the defined term "Execution Date" and phrases "day of settlement of the transaction agreement" and "date as provided by the transaction agreement" be replaced with a single term or phrase. LADWP recommends use of the phrase "Compliance Instrument Transfer Settlement Date" instead of "Execution Date." (LADWP 1)

Comment: With respect to the specific text, CPEM offers the following comments: Section 95921(a)(3)(B) and Definition 130 “Execution Date”: Section 95921(a)(3)(B) has been modified to subject parties to violation or penalty if a transaction is completed “More than three days after the execution date or termination date of the transaction agreement for which the transfer request is submitted.” New definition 130, in turn, defines “Execution Date” as “a provision of a transaction agreement that requires the transfer of compliance instruments on or before a date specified in the agreement.”

CPEM submits that the definition of “execution date” and the reference in Section 95921(a)(3) are inappropriate and can lead to substantial confusion. In standard commercial parlance, the “execution date” of an agreement is the date on which both parties have legally committed to the agreement, or a specified date near such time. Indeed, “Execution Date” is often a defined term in agreements to transfer carbon instruments (see, for example, the Form of Master Allowance/Offset Credit Purchase Agreement (California) published by San Diego Gas & Electric Company, and available http://www.sdge.com/ghg-offset-credit-rfo- september-2013). Creating a newly defined term that means something materially different than the term in standard commercial use can lead to unnecessary confusion. The proposed regulations specifically contemplate that, under some transactions, a transfer request may be set to take place more than three days from the date the parties enter into a transaction.

Please see, for example, proposed section 95921(b)(4), which clearly demonstrates that the regulations are not intended to require transfer of carbon instruments within three days of the execution date, as that term is normally used. Rather than attempt to redefine “execution date” from its standard meaning, CPEM recommends adoption of the term “Agreement Transfer Date” (as proposed in the October 18, 2013 comments filed by the Southern California Public Power Authority). (CPM 1)

Comment: Defined term “Execution Date” should be changed to avoid confusion: Proposed new section 95802(a)(130) of the Regulation defines the term “Execution Date” as “a provision of a transaction agreement that requires the transfer of compliance instruments on or before a date specified in the agreement.” The term appears to have been defined for proposed new section 95921(a)(3)(B), which sets out the timeframe within which compliance instrument transfers must take place. As discussed in section XV below, SCPPA considers that there is no need for the Regulation to contain any restrictions on transfer timelines that refer to transaction agreements, as transaction agreements will contain penalties for late transfers. Therefore, section 95921(a)(3)(B) should be deleted, and in which case there would be no need to define “execution date.”

However, if section 95921(a)(3)(B) is retained, the term “execution date” should be changed. This term is also used in section 95852.1.1(a)(1)(A), in relation to contracts for purchasing biomass-derived fuel. In this context the definition is inappropriate, as agreements for biomass-derived fuel won’t necessarily require the transfer of any compliance instruments. This indicates a key problem with the defined term. The term “execution date,” in relation to an agreement, is commonly understood to mean the date on which the agreement is executed, i.e. signed by the parties to the agreement. This is very different from the meaning assigned to the term by the definition in section 95802(a)(130). To avoid confusion, if the definition is not deleted, the defined term should be changed from “Execution Date” to something more accurate such as “Agreement Transfer Date.”

Recommendation: SCPPA’s proposed change to section 95802(a)(130), absent deletion of the section together with deletion of section 95921(a)(3)(B), is set out below:

(130) “Agreement Transfer~~Execution~~ Date” means a provision of a transaction agreement that requires the transfer of compliance instruments on or before a date specified in the agreement. (SCPPA 1)

Response: In response to stakeholder comments, ARB staff has deleted the term “Execution Date” from the proposed regulation as part of the 15-day amendments. Instead of “Execution Date,” the proposed regulation now requires the entry of the “expected termination date of the agreement”. Staff agreed with comments that the concept of “execution date” did not fit the wide variety of transaction agreements in effect. Staff did explore the use of the revision suggested in the comment, but determined that some transaction agreements may not be specific enough to identify a date. Finally, staff replaced the “Execution Date” requirement with a requirement to specify an expected termination date. This allows staff to determine whether there are terms in the transaction agreement to be satisfied after the transfer is accomplished.

H-3.31. Comment: The definition of “Over-the-Counter” should be revised for clarity: Proposed new section 95802(a)(244) defines the term “Over-the-Counter” as “the trading of carbon compliance instruments, contracts, or other instruments not listed on any exchange.”

This definition is useful, but certain changes would increase its clarity and reduce redundancy. First, the term “carbon compliance instrument” is not used elsewhere in the Regulation; it should be changed to the usual term “compliance instrument.”

Second, the term “over-the-counter” is used only in section 95921 in relation to transactions involving compliance instruments other than on exchanges. Therefore, the reference to “contracts or other instruments” should be deleted as this term only refers to the trading of compliance instruments.

Recommendation: SCPPA’s proposed changes to section 95802(a)(244) are set out below:

(244) “Over-the-Counter” means the trading of ~~carbon~~ compliance instruments, ~~contracts, or other instruments~~ not listed on any exchange. (SCPPA 1)

Response: Staff agrees with the comment that definition (244) “Over the Counter” needs clarification, but does not agree with the recommended revision. Instead, staff concluded that a suggested revision contained in another comment better corrected the lack of clarity in the definition. The definition therefore now reads: “Over-the-Counter” means the trading of carbon compliance instruments, contracts, or other instruments not executed or entered for clearing on any exchange.

H-3.32. Comment: § 95802(336) Definition of Spot: The proposed amendments add a new definition, "spot," which "means a contract for the immediate delivery of and payment for a product." In the proposed definition, the terms "contract" and "immediate" are not defined. The use of the term "spot" in commodity markets appears to be more complex than defined in the cap-and-trade amendments.

In 17 CFR §15.00(a), "Cash, or Spot, when used in connection with any commodity, means the actual commodity as distinguished from a futures or options contract in such commodity."

The CFTC Guidance on, and Acceptable Practices in, Compliance with Core Principles (17 CFR Part 36, Appendix B) discusses "spot-month positions:"

"Limitations on spot-month positions. Spot-month limits should be adopted for significant price discovery contracts to minimize the susceptibility of the market to manipulation or price distortions, including squeezes and corners or other abusive trading practices."

Thus, LADWP recommends that the definition either be further clarified or that CARS rely on the CFTC definitions and interpretations as they relate to spot transactions. (LADWP 1)

Response: The point is moot because definition (336) “Spot” has been deleted with the removal of the term from the proposed regulation.

H-3.33. Comment: IETA appreciates the added clarity given to the definition of “Futures” in these latest amendments. However, there remains some confusion and inconsistency in the way that ARB refers to secondary and/or spot market transactions. A few examples follow:

- On page 53 of ARB’s proposed amendments, the definition of “Spot” is a contract for the immediate delivery of and payment for a product. Yet in the breakdown of the three different transaction types (§95921(b)(2)), it appears that trades for delivery within 3 days could be considered spot, which might contradict ARB’s definition of spot as “immediate delivery”. Added clarity would be appreciated.

- Further to the previous point: it's possible that "futures" can be traded up to 3 days before delivery. Therefore, should such a trade be considered "spot" or "futures"? This confusion between "futures" and "spot" definitions makes the reporting requirement unclear in section 95921(b)(5)(C), which requests that entities "identify the contract as spot or futures".
- The definition of "over-the-counter" turns on whether the subject matter of the trade is listed on an exchange, not whether the trade takes place through an exchange. Since the third category relates to agreements for sale of compliance instruments through any contract arranged through an exchange or Board of Trade, the definition seems deficient. ARB should consider replacing the word "listed" with the words "executed or entered for clearing". The resulting definition would be: "Over-The-Counter means the trading of carbon compliance instruments, contracts, or other instruments not executed or entered for clearing on any exchange." (IETA 1)

  Response: Staff agrees with the concerns expressed in the comment. However, Staff has proposed as part of the 15-day changes to remove the requirement which uses the terms "spot" and "future" (proposed section 95921(b)(5)(C)) because the same information can be obtained when the entity identifies the exchange and the code assigned by the exchange to identify the contract being traded (proposed section 95921(b)(5)(A) and (B)). Since they are no longer needed, Staff is also proposing to eliminate the definitions of "spot" contained in proposed section 95802(a)(306) and "futures" contained in proposed section 95802(a)(153). This should end the ambiguity.

  Staff agrees with the comment on the term "over the counter" and has modified the definition contained in proposed section 95802(a)(306) accordingly.

H-3.34. Comment: Section 95921(b)(1)(B) of the proposed amendments states that the seller of units in a transaction must need to know the "… identification of a primary account representative or alternative account representative for the destination account confirming the transfer request, if confirmation of the transfer request is required."

IETA members with significant experience in deliveries of cleared futures maintain that requiring such an additional test for a transfer will add unneeded complication. Specifically PARs and AARs at firms regularly change and it would not be common for counterparties to keep each other abreast of these personnel changes.

Should such a provision be implemented, several considerations follow. How quickly would CITSS be updated for personnel changes submitted by the buying party? Further, depending on how the test is implemented (e.g. drop down name selection vs. free form) and whether spelling of the names need to match exactly, transfer initiations may be delayed due to spelling errors. Finally, since all transfers of allowances that originate from trading must be confirmed by the buying PAR or AAR, what is the added value of having the seller input those names to initiate the transfer? Added clarification on these questions would be appreciated. (IETA 1)

Response: In response to stakeholder comments, the requirement to identify the account primary account representative or alternative account representative of the destination account has been deleted in the 15-day changes.

H-3.35. Comment: Turlock Irrigation District ("TID") submits the following comments regarding the California Air Resources Board ("ARB") September 4th, 2013 Proposed Amendments to the California Cap- and-Trade Program ("September 4th Amendments"). In these comments, TID expresses concerns with the expanded informational requirements proposed in the September 4th Amendments. As discussed below, TID provides the following comments:

(1) It is not clear how the collection of additional allowance transfer information and new restrictions on allowance transfers aids the ARB in implementing and enforcing the Cap- and-Trade regulation;

The collection of pricing and contract information in CITSS is beyond the scope of ARB's market monitoring responsibilities: The September 4th Amendments would revise Section 95921(b) of the Cap-and-Trade regulation to require the submission of detailed information about an allowance transfer before the ARB will approve a transfer. The information requested includes, among other things, detailed transaction-specific information and copies of contracts. These new informational requirements combined with other new informational requirements (e.g., employee and contractor information) go beyond the scope of information that was originally intended to be collected by the ARB.

The reporting and Cap-and-Trade programs should be designed to minimize the administrative burdens and transactional costs of regulated entities. The new informational requirements under Section 95921(b) would include: the type of transfer, dates for execution of the transfer agreement and settlement, price of the compliance instruments, and exchange information (among many other information requirements). In addition, the ARB regularly collects contracts for allowance transfers. The ARB has not specified why this information is needed or how the information furthers the ARB's Market Monitoring responsibilities.

According to the ARB, "the market monitor will monitor allowance holding and transfer activity to detect design flaws in the market operating rules, standards, procedures or practices, or to detect structural problems in the market." The systematic collection of detailed transaction- specific information (in particular, copies of contracts) does not further the function of detecting design flaws in the Cap-and-Trade market. The existing reporting requirements (e.g., reporting on transfer prices and ensuring that transfers do not violate the holding limitations) provide more than enough information for the ARB to detect design flaws.

For these reasons, the ARB should not place new restrictions on allowances transfers or require additional reporting requirements under Section 95921(b). Section 95921(b) should not be amended as proposed in the September 4th Amendments. (TID 1)

> **Response:** The systematic collection of detailed transaction-specific information (including copies of contracts) is necessary for monitoring activity in the CITSS. ARB staff understands this monitoring authority to exist pursuant to ARB's authority to design and implement the Cap-and-Trade Program.

H-3.36. Comment: Section 95921(b)(4)(E-G): Transfer requests: Section 95921(b)(4)(E-G) require that entities enter complex pricing information on transfer requests into the cap-and-trade tracking system. This information has no value to market monitoring and will require a burdensome effort for entities to fit non-standard information into the standard format in the tracking system. Section 95921(b)(4)(E-G) should be deleted.

> **Recommendation:** Modification to Section 95921(b)(4)(E-G) (Conduct of Trade)
>
> (E) If the transaction agreement specifies a fixed price for the compliance instruments, provide the price in U.S. dollars or Canadian dollars.
> (F) If the transaction agreement sets the price as a cost base plus a margin, then provide the cost base and the margin.
> (G) If the transaction agreement does not specify the price using one of the above formats, provide a brief description of the pricing method. (SEMPRA 2)
>
> **Response:** As staff has stated previously, the intent of the changes is to provide a path for entering transfer information into CITSS that matches the type of transaction agreement involved. The problem described in the comment, that "non-standard" information must be forced into a standard format, describes the current situation that staff is attempting to rectify. CITSS will be modified by January 1, 2015 so that the account representatives can identify the type of transaction agreement and then be presented with data fields that match their transaction agreement structure. This should make data entry quite rapid.
>
> Staff disagrees with the assertion in the comment that the data have no value for market monitoring. For example, agreements that set prices based on some publicly-reported index or price are vulnerable to schemes that seek to manipulate the underlying index or price. To deal with this risk ARB staff monitors related markets, such as futures markets. Another example arises if a number of agreements were to use the same index. If ARB staff was not aware of this fact, then having a number of transfers reported at nearly the same price would result in staff investigating potential collusion.
>
> Currently, the only way staff can deal with these issues is to call in transaction agreements and examine the terms. Staff has reviewed a number of transfer

agreements and has concluded, based on the terms staff has observed in actual agreements, that the information required by the proposed text will be readily available to the account representative when needed.

H-3.37. Multiple comments: Conduct of Trade/Information for Transfer Requests (95921(b)(1)(B): This section requires the identification of an account representative for destination account. This information is already available in CITSS.

Recommendation: Delete this requirement. (WSPA 1)

Comment: Section 95921(b)(1): New section 95921(b)(1) requires the entity entering information for a transfer request to provide the identification of the two primary account representatives and/or alternate account representatives for both the source account (§95921(b)(1)(A)) and the destination account (§95921(b)(1)(B)). CPEM submits that this is not necessary: the system already holds the identity of these persons, and checks and balances are in place to ensure that the correct persons exercise their respective obligations.

Perhaps more importantly, the entity entering the transfer request for the source account has no basis for knowing, and may not be entitled to know, who is authorized to act for the destination account. Adding this requirement adds an unnecessary level of complexity to agreements, as it would require parties to update counterparties of any changes to their internal delegations, etc. (CPM 1)

Response: Staff agrees with the comments and has removed the provision as part of the 15-day changes.

H-3.38. Comment: Conduct of trade: CPEM strongly urges ARB to reconsider the proposed modifications on Conduct of Trade found in § 95921. CPEM appreciates ARB's desire to have information necessary to perform its market monitoring function. However, CPEM submits that the proposed regulations calls for a level of transactional detail that is beyond the scope of what is needed, creates unnecessary burdens on transactions, and potentially exposes highly confidential information. ARB already has enforcement tools at its disposal sufficient to keep a careful reign on the market. ARB already has full access to the balance of compliance instruments in various parties' accounts, will know the prices bid by all parties at auction, and will know the price paid for compliance instruments traded on CITTS. If any trade triggers a concern, ARB already has authority to request access to underlying contractual documents at that time. Requiring all parties to submit extensive documentation for routine trades, when there is no indicia of any kind of a market issue, is unnecessarily burdensome on both market participants and ARB Staff. This proposal to require such detailed information be provided through CITSS is particularly troubling given the proposed language of the CITSS User Agreement, Section 1.4, which specifies that ARB may disclose information provided by users to the public "to the extent that disclosure is not prohibited by California Law." To the extent the ARB does require filing of this information, the regulations should be modified to reflect that all information shall be maintained on a strictly confidential basis, shall be exempted from the California Freedom of Information Act to the maximum extent allowed by law, and shall not otherwise be disclosed absent compelling need and legal requirement. (CPM 1)

> **Response:** The comment is not specific as to which parts of section 95921 give rise to the commenter's concerns. In comparison with the existing information reporting requirements, account representatives should observe only insignificant changes in information required for over-the-counter agreements with a delivery time of three days or less and for exchange agreements. The only significant expansion of information would be for over-the-counter with delivery times longer than three days that determine price based on an index plus a margin (sections 95921(b)(4)(F) and (G).) Based on reviews of transaction agreements, staff believes these are rare and staff has observed that the data required are readily available to the account representatives in the agreements. Together with changes planned for CITSS, the burden should be minimal.
>
> Some of the commenter's concerns may also be directed at sections 95921(b)(4)(C) and (D), which as originally proposed would have required additional information on agreements that involved multiple transfers or multiple products. These have been simplified as part of the 15-day amendments to "flags" that indicate the presence of such terms, but no longer require details.

H-3.39. Comment: Section 95921(a)(3): Transfer requests: Sections (B) and (C) of 95921(a)(3) should be deleted to reflect consistency with the proposed changes in 95921(b)(4). The latter section acknowledges that there can be transaction agreements that involve multiple transfers of compliance instruments over time and which "take place more than three days from the date the parties enter into the transaction agreement." Further, Section 95921(f)(I)(B) expressly allows forward market transactions where transfer of compliance instruments may be well after the transfer of consideration. Deleting Sections 95921(a)(3)(B) and 95921(a)(3)(C) would acknowledge that there are agreements where the timing of the transfers of consideration and compliance instruments may not match.

> **Recommendation:** Modifications to 95921(a)(3)(B) and 95921(a)(3)(C) (Conduct of trade):
>
> ~~(B) More than three days after the execution date or termination date settlement day of the transaction agreement for which the transfer request is submitted; or.~~
>
> ~~(C) More than three days after the transfer of consideration from the purchaser of the compliance instrument to the seller as provided by the transaction agreement; or~~ (SEMPRA 2)
>
> **Response:** ARB has modified section 95921(a)(3) as part of the 15-day changes to renumber it to (a)(4) – a new provision for transfers through December 31, 2014 has been added as the new (a)(3). ARB is proposing to

modify former section 95921(a)(3)(B) (now (a)(4)(B)) to reflect changes to 95921(b)(4), which is also changing. The changes reflect the proposal to use the expected termination date of the agreement to trigger the transfer request deadline. ARB believes this captures the intent of the comment. ARB is also proposing to eliminate former section 95921(a)(3)(C), as the comment proposes.

H-3.40. Comment: The issues that we'd like to comment on today relate to allowance transfer issues and specifically trading restrictions. It's identified in Appendix A as one of the issues that the ARB is going to continue to work on next year. And we're hoping that staff will take a hard look at whether or not the requirements are overly broad and whether or not some of the new requirements, specifically the collection of allowance transfer information, may impose new additional transactional costs on parties engaging in allowance transfers. (TID 2)

Response: Staff believes that the collection of allowance transfer data is crucial for effective market monitoring. As the commenter notes, staff will continue to evaluate these requirements to ensure effective implementation.

Implications to Limited Exemptions

H-3.41. Comment: CARB has substantially revised the provisions in section 95920 for limited exemptions to the holding limits. The revisions seem to be intended to increase the limited exemption, so that allowances up to the level of an entity's emissions to date for a compliance period would not be included in the holding limit. However, CARB's revisions to 95920(d)(2)(B) would have the unintentional consequence of eliminating the holding limit exemption between January and October, 2014. To address this, we recommend that CARB add language to provide for a limited exemption for the January – October period. (WPTF 1)

Response: In response to stakeholder comments, section 95920(d)(2)(B) has been rewritten as part of the 15-day changes so that the value of the limited exemption on July 1, 2014, the planned effective date of the proposed regulation, will be the same as it would have been on that date under the existing regulation. The existing schedule of further increases and decreases in the limited exemption is maintained with only minor changes in dates.

H-3.42. Comment: Limited Exemption from Holding Limit: Section 95920(d)(2)(B), with the proposed modification allows NO "Limited Exemption from the Holding Limit" until October 1, 2014. In the original regulation, there was a limited exemption starting June 1, 2012, which increased on October 1st each year, based on the entity's recent emissions data report with positive/qualified positive emissions.

Recommendation: Retain original language in Section 95920(d)(2)(B) " On June 1, 2012, the limited exemption will equal the annual emissions most recent emissions data report that has received a positive or qualified positive emissions data verification statement." Also retain original language in 95920(d)(2)(C). "Beginning in 2013 on

October 1 of each year the limited exemption will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year". (WSPA 1)

> **Response:** In response to stakeholder comments, section 95920(d)(2)(B) has been rewritten as part of the 15-day changes so that the value of the limited exemption on July 1, 2014, the planned effective date of the proposed regulation, will be the same as it would have been on that date under the existing regulation. The existing schedule of further increases and decreases in the limited exemption is maintained with only minor changes in dates.

H-3.43. Comment: Limited exemption from holding limit: The Proposed Amendments include new language that would revise the limited exemption from the holding limit. However, assuming the Proposed Amendments are intended to become effective prior to October 1, 2014, then covered entities will have no limited exemption whatsoever, until October 1, 2014. This could result in unintended violations of the holding limit among covered entities and should be fixed by CARB prior to finalizing the Proposed Amendments.

The proposed revisions to the limited exemption from the holding limit should be revised so there is no gap between when the proposed amendments become effective and the limited exemption first applies: The Regulation currently provides a limited exemption from the holding limit, which is the number of allowances exempt from the holding limit calculation after they are transferred by a covered entity to its compliance account. The Regulation states that "[o]n June 1, 2012 the limited exemption will equal the annual emissions most recent emissions data report that has received a positive or qualified positive emissions data verification statement" and "[b]eginning in 2013 on October 1 of each year the limited exemption will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year."

The Proposed Amendments would eliminate these provisions and would instead begin calculating the limited exemption on October 1, 2014 (based on emissions in the 2012, 2013 and 2014 emissions data reports receiving a positive or qualified verification statement). Thus, if the Proposed Amendments should become effective at any date prior to October 1, 2014, covered entities will have *no* limited exemption and could unintentionally violate the holding limit.

> **Recommendation:** To maintain the limited exemption at the levels established by the current Regulation until the Proposed Amendments become effective, Calpine proposes that the Board revise the limited exemption provisions as follows:
>
> § 95920. Trading.…

(d) The holding limit will be calculated for allowances qualifying pursuant to section 95920(c)(1) as the sum of:…

(2) Limited Exemption from the Holding Limit.…

(B) On June 1, 2012 the limited exemption will equal the annual emissions subject to a compliance obligation pursuant to section 95851(a) reported by the most recent emissions data report that has received a positive or qualified positive emissions data verification statement. On October 1, 2013, the limited exemption will be increased by the annual emissions subject to a compliance obligation pursuant to section 95981(a) reported by the most recent emissions data report that has received a positive or qualified positive emissions data verification statement. On October 1, 2014, the limited exemption will be calculated as the sum of the annual emissions data reports received in 2012, 2013, and 2014 that have received a positive or qualified positive emissions data verification statement for emissions that generate a compliance obligation pursuant to section 95851(a). (CALPINE 1)

Response: In response to stakeholder comments, section 95920(d)(2)(B) has been rewritten as part of the 15-day changes so that the value of the limited exemption on July 1, 2014, the planned effective date of the proposed regulation, will be the same as it would have been on that date under the existing regulation. The existing schedule of further increases and decreases in the limited exemption is maintained with only minor changes in dates.

H-3.44. Multiple comments: ARB Market Design Needlessly Prohibits Robust Transaction Processes: The proposed amendments provide relief in some areas, such as true up allowances and the treatment of future vintage allowances under the holding limit rule. However, Chevron continues to be challenged by holding limits that impact our ability to operate efficiently in the market. To that end, Chevron supports the Joint Utilities Proposal changing the requirement for the limited exemption. Enabling allowances corresponding to the limited exemption to be placed in the compliance entity's holding account will allow compliance entities the flexibility to efficiently manage their compliance instrument portfolio within the confines of a quantitative holding limit. Because the holding limit does not account for the size of a compliance obligation, this change is particularly important for large compliance entities.

Holding Limit: Issue: the holding limit is too small for covered entities with large compliance obligations.

Recommendation: Proposed Change: amend Section 95920(d)(2)(A) to make the limited exemption to the holding limit apply to an entity's allowances in both the holding and compliance account.

Holding Limit:

§ 95920. Trading.…

(d) …

(2) Limited Exemption from the Holding Limit.

(A) The limited exemption from the holding limit (limited exemption) is the maximum number of allowances which can be held in an entity's <u>holding account or</u> compliance account that will not be included in the holding limit calculated pursuant to section 95920(c)(1). To qualify for inclusion within the limited exemption, allowances must be placed in the entity's Compliance Account <u>or Holding Account.</u> (CHEVRON 2)

Comment: Section 95920(a): As Shell Energy stated in its August 2 comments, the "holding limit" (for entities with a direct corporate association) referenced in this section of the Rules is unreasonably low. The holding limit fails to take into account the nature of a covered entity's business. Different holding limits should be established based on the type of business in which the entity is engaged. The current limits are punitive, especially for companies that have large compliance obligations and/or large purchase commitments by virtue of new or existing contractual arrangements. This latter point (new or existing contractual arrangements) is particularly important, because the limited exemption offered by the Compliance Account does not help an entity that has to transfer large volumes to a third party by virtue of some separate contractual arrangement. The holding limits should be re-examined. (SHELL 1)

Comment: Section 95920. Holding Limit Should Ensure Equitable Treatment of Regulated Entities: By imposing the same holding limit calculation on all entities, regardless of operational size and relative compliance obligations, the regulation unfairly and unnecessarily discriminates against larger regulated entities, effectively forcing them to procure at higher costs that, in the case of utilities, are then passed on to their customers. Below, PG&E outlines its holding limit proposal which would address this inequity. In addition, changes to the Proposed Regulation between the July discussion draft and the 45-day language inadvertently impact the limited exemption to the holding limit, effectively decreasing the quantity of allowances dedicated for compliance that are exempt from the holding limit. PG&E also proposes a simple modification to address this issue.

1. Allowances in a Compliance Account Should not Count Against the Holding Limit

The holding limit calculation permits smaller entities to comply at lower costs by effectively allowing them to bank a higher proportion of lower-cost instruments for their compliance obligation. While the current holding limit/ limited exemption allow larger entities to procure allowances to meet their obligation over time, it fully limits the cost containment aspects of banking allowances. PG&E proposes that ARB retain the standard holding limit for all entities registered with ARB. In addition to the standard holding limit:

- Entities with a compliance obligation may apply their limited exemption to allowances held in their holding account; and
- Allowances in a compliance account would not count against the holding limit.

This minor modification will provide compliance entities with flexibility and planning opportunities that any successful carbon market should have. The proposal would only impact entities with compliance obligations, enabling them to maintain more banked allowances in their holding accounts, thus increasing the number of allowances available to trade or transfer, reducing operational risks, and improving market liquidity. The proposal also enables larger compliance entities to more effectively utilize the banking provision currently available in the regulation, and provides greater flexibility to manage compliance costs. At the same time, by allowing entities to place more allowances in their compliance accounts, ARB would in effect make those allowances usable only for compliance purposes, reducing the possibility of market manipulation with respect to those allowances. Also, this proposal does not interfere with or undermine the suite of market manipulation prevention tools already in place (purchase limits, continuous market monitoring, an extensive registration process, and personal attestations).

Recommendation: 95920(d)(2) Limited Exemption from the Holding Limit.

(A) The limited exemption from the holding limit (limited exemption) is the maximum number of allowances which can be held in an entity's holding account ~~compliance account~~ that will not be included in the holding limit calculated pursuant to section 95920(c)(l). ~~To qualify for inclusion within the limited exemption, a~~Allowances ~~must be~~ placed in ~~the~~ a Covered E~~e~~ntity's compliance account are (1) exempt from the holding limit calculated pursuant to section 95920 (c)(l); and (2) are exempt from the limited exemption from the holding limit calculated pursuant to this section 95920 (d)(2).

2. Removal of the Annual Compliance Obligation Should Not Decrease an Entity's Limited Exemption from the Holding Limit

The Proposed Regulation's removal of the annual compliance obligation inadvertently decreases an entity's limited exemption from the holding limit because those otherwise-retired annual allowances remain in the compliance account and count toward the limited exemption. This outcome introduces an additional constraint because under the current Regulation, those allowances associated with an annual compliance obligation are retired and removed from the compliance account, effectively increasing the limited exemption by the amount of the retirement. To address this issue, PG&E proposes that ARB increase the limited exemption calculation by the annual compliance obligation that otherwise would have been retired under the current Regulation. With this change to Section 95920(d)(2), ARB's regulatory changes intended to preserve the value of offsets, do not negatively impact an entity' limited exemption amount.

Section F On November 1 of the calendar year following the year a covered entity has an annual compliance obligation pursuant to section 95855, the limited exemption will be increased by the sum of the entity's annual compliance obligation over that year. On December 31 of the calendar year following the end of a compliance period, the limited exemption will be reduced by the sum of the entity's compliance obligation over that compliance period.

3. Limited Exemption Calculation Prior to October 2014 Should Remain Intact

The Proposed Regulation deletes all references to the calculation of the limited exemption prior to October 2014. Compliance entities should not be denied their limited exemptions in the event that processes to codify the amended regulation are completed prior to October 1, 2014; we assume it is not ARB's intent to do so.

Recommendation: Accordingly, PG&E recommends maintaining existing references to the limited exemption calculation in Section 95920(d)(2):

(B) On October 1, 2012, the limited exemption will equal the annual emissions of the most recent emissions data report that received a positive or qualified positive emissions data verification statement for emissions that generate a compliance obligation pursuant to section 95851(a). On October 1, 2013, the limited exemption will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year for emissions that generate a compliance obligation pursuant to section 95851(a). On October l, 2014 the limited exemption will be calculated as the sum of the annual emissions data reports received in 2012, 2013, and 2014 that have received a positive or qualified positive emissions data verification statement for emissions that generate a compliance obligation pursuant to section 9585l(a). (PGE 2)

Comment: CCEEB believes that an open market allows participants to comply at the lowest increment cost, thereby improving program cost effectiveness and freeing market entities to find the best and most innovative solutions to reduce GHGs. Unfortunately, portions of the current regulation may unnecessarily constrain market liquidity. Of particular concern are:

Holding Limits

- The current holding limit is too restrictive for regulated entities with large compliance obligations and unnecessarily locks away significant amounts of allowances that might otherwise be available to the market. This creates an uneven playing field that favors traders over regulated entities. Compliance entities, especially those with large compliance obligations, must be able to hold and trade a larger portion of their allowances in order to adequately manage risk.
- CCEEB recommends that the program allow compliance entities to hold, in holding accounts, sufficient allowances to cover their obligation for the entire

compliance period based on a rolling three-year emissions obligation. This change would free up allowances for the major compliance entities and improve market liquidity because an entity could hedge its forward risk without major complications. While there are still allowances locked in compliance accounts in some years, the increase in holding limits makes these limitations much more manageable.

- Holdings limits are intended to prevent one entity from cornering the market. However, holding limits also place significant strain on compliance entities. Instead, CCEEB recommends moving towards monthly auctions, which would prevent any one entity from cornering the market while at the same time improving liquidity market. (CCEEB 1)

Response: Staff disagrees with the comments asserting that the holding limit is too low for compliance entities. As proposed in the 45-day text, compliance entities are allowed to exempt their compliance holdings from the holding limit calculation when placed in the compliance account. The limited exemption allows entities to hold enough allowances in their compliance accounts to take advantage of the banking opportunities allowed by the regulation. The limited exemption allows them to be somewhat “long” in their compliance account holdings, relative to their obligations. Speculative holdings in holding accounts are treated identically under the holding limit for all registered entities.

Staff disagrees with the recommendations that holdings should qualify for the limited exemption when placed in holding accounts or that allowances in the compliance account should not count against the limited exemption. The proposals could allow large entities to artificially tighten the market as part of a scheme to manipulate the market. Manipulative schemes often are comprised of two discrete steps. First, an entity must remove or control enough of a market to raise prices and reduce competition from other sellers. Second, an entity must have sufficient supply available to sell at the resulting artificially high prices. While the limited exemption allows large entities to accumulate in excess of their compliance obligations, which could tighten the market, the compliance account provisions limit their ability to profit from resulting high prices.

Staff does not agree with the assertion made in the comment that the holding limit unnecessarily interferes with contractual obligations between a covered entity and a second covered entity. Staff has observed a number of agreements that require transfers of large quantities of allowances between covered entities. The holding limit calculation currently allows entities to hold around 6 MMT in their holding accounts at any one time. This will increase to over 11 MMT in 2015. Staff has concluded that these limits would not interfere with contractual obligations. Staff also notes that many contracts involve multiple transfers. Even if the contractual quantities transferred were large relative to the holding limit, the constraint could be resolved through multiple transfers.

As part of the 15-day changes, staff has modified the effective dates of the changes in the calculation of the limited exemption so that the discontinuity in calculating the limited exemption cannot occur.

The comment that the change to the annual surrender provision reduces the number of allowances that a covered entity may place in its compliance account within the Limited Exemption is moot because staff has modified the proposed text to restore the existing provision for actual retirement.

Finally, and contrary to the assertion in the comments, staff does not believe more frequent auctions would prevent market corners without holding limits since corners could be effected through a combination of auction and secondary market purchases.

H-3.45. Comment: IEP Supports the Creation of a Limited Exemption Holding Account. The Limited Exemption Holding Account will be a temporary holding area for entities that qualify for an allocation under Section 95870.16 The Limited Exemption Holding Account is designed to hold future vintage allowances that are directly allocated to entities, like legacy contract generators, where a violation of the holding limit might otherwise occur.

IEP supports this proposal and agrees that the Limited Exemption Holding Account is needed to avoid potentially placing entities subject to a direct allocation in violation of the holding limit. (IEPA 1)

Response: Thank you for the support. The Limited Exemption Holding Account was renamed the annual allocation holding account in the 15-day regulatory modifications but will serve the same function as a holding area for allowances that are allocated prior to the year in which they become current vintage.

H-3.46. Comment: IETA has previously detailed why holding limits in California's program pose a systematic disadvantage to large final emitters (LFEs) whose emissions exposure may be greater than the holding limit itself. The holding limit prevents these LFEs from accessing the full benefits of banking allowances, an important cost containment mechanism within the cap-and-trade program.

IETA maintains that with the additional market oversight provisions that ARB has effectively put into place, a holding limit is not necessary to prevent market manipulation. If a holding limit must be in place, IETA reiterates that it should be made relative to an entity's compliance obligation so that it does not disproportionately affect LFEs.

Compounding the problem the holding limit presents is the automated compliance surrender order that is outlined in the section above, and with that the proposal to eliminate annual compliance surrender obligations.

With ARB no longer retiring 30% of an entity's compliance obligation per year (in non-compliance years) – and without an entity permitted the ability to voluntarily surrender compliance units in non-compliance years to satisfy its compliance obligation – an entity must carry an additional number of compliance units in its compliance account (equal to 30% of its annual emissions obligation).

Since the limited exemption has not changed, and because an entity now must hold an additional 30% of its annual compliance obligation instead of being retired, it further squeezes the amount an entity can hold in its compliance account. For smaller entities this might not pose a problem.

However, for LFEs carrying a significant compliance obligation, who must store units in their compliance account because the holding limit prevents them from holding a requisite number of units in their holding accounts, this is a significant problem.

IETA suggests two solutions:

1. Eliminate or increase holding limits so that LFEs are not disproportionately burdened compared to the rest of the market. Doing so would eliminate much of the concern regarding ARB's proposal to eliminate the annual compliance surrender obligation (though there would still be issues with the automated compliance surrender order).

2. Allow entities to surrender compliance instruments at any time (to count against their compliance obligation). Doing so would alleviate the limitation to compliance account holdings, particularly with the limited exemption not being adjusted. (IETA 1)

> **Response:** The comment that the change to the annual surrender provision reduces the number of allowances that a covered entity may place in its compliance account within the Limited Exemption is moot because staff has modified the proposed text as part of the 15-day modifications to restore the existing provision for annual retirement.
>
> The first recommendation, suggesting the elimination or increase of the holding limits, is beyond the scope of the proposed changes.
>
> Staff does not agree with the second recommendation. Staff had considered allowing early compliance surrender when first developing the regulation, but determined that it could be used to artificially tighten the market as part of a scheme to manipulate the market. Manipulative schemes often are comprised of two discrete steps. First, an entity must remove or control enough of a market to raise prices and reduce competition from other sellers. Second, an entity must have sufficient supply available to sell at the resulting artificially high prices.
>
> The Limited Exemption allows an entity to hold enough allowances in its Compliance Account to take advantage of the banking opportunities allowed by

the regulation. The existence of the Limited Exemption, however, reduces the ability of an entity to artificially tighten the market. Allowing early retirement would eliminate the protection.

H-3.47. Comment: Trading (Section 95920): In this amendment, ARB proposed not to retire the annual compliance obligation in the compliance account, but only to review and ensure there are adequate credits in the account. If adopted, this proposed amendment will impose more restrictions in the number of allowances qualified for limited exemption because the allowances equal to each annual compliance obligation will continue to reside in the compliance account instead of being retired to the program retirement account. This new restriction will add more constraint to entities with a large compliance obligation such as fuel suppliers creating an environment more susceptible to market manipulation.

Recommendation: To avoid this potentially adverse market effect, we recommend removing the requirement for having to place allowances in the compliance account to qualify for limited exemption (§95920 (d)(2)). This flexibility will enable participants to optimize trade activities and better manage the cost exposure associate with the market fluctuation. We suggest deleting the requirement for placing allowances in the Compliance Account in the last sentence of the following section:

§95920 (d)(2) Limited exemption from the Holding Limit: The limited exemption from the holding limit is the maximum number of allowances which can be held in an entity's compliance account that will not be included in the holding limit calculated pursuant to section 95920 (c)(1). ~~To qualify for inclusion within the limited exemption, allowances must be placed in the entity's Compliance Account~~. (WSPA 1)

Response: Most of the comment is outside the scope of the proposed changes. First, ARB staff has not proposed changes to the formula that governs the size of the Holding Limit. Second, ARB staff has not proposed changes to the requirement that allowances be placed into the compliance account to qualify for exemption from the Holding Limit under the limited exemption. ARB staff has only proposed a reorganization of the section to remove dates already past, make minor changes in the dates to revisions of the limited exemption, and clarify the emissions obligations that are included in the limited exemption calculation. ARB staff has addressed the same issues in previous Staff Reports and Final Statements of Reasons for earlier rulemakings..

ARB's Authority

H-3.48. Multiple comments: Section 95921(b)(3)(C), (4)(E,F,G), (5)(E): The Staff's proposed amendment would require disclosure of the price term in a transfer request for the sale of compliance instruments, whether the transaction is over-the-counter or an exchange-based agreement. The Staff's proposal would require disclosure of a "fixed price" or, in the alternative, a description of the pricing method in the secondary market transaction. The Staff attempts to justify a "price disclosure" requirement by stating that the "provision is needed to enable ARB market monitoring staff to understand the basis for pricing carbon instruments." Staff Report at p. 200. The Staff also asserts that the "provision is needed to allow ARB to interpret the price entered for the transfer request as part of market monitoring." Id. 199.

The Staff's reasoning does not justify a price disclosure requirement; disclosure of the price of a private transaction is not supported by law. The ARB does not approve or regulate the prices of compliance instruments that are sold in secondary market transactions. The ARB also does not regulate or limit the price that an entity may charge to sell, or pay to purchase compliance instruments in the secondary market. Secondary market price regulation is outside the scope of the ARB's authority under AB 32. The ARB does not have the authority to require mandatory price disclosure as a part of a participating entity's "transfer request."

As Shell Energy stated in its August 2 comments, mandatory price disclosure to the ARB would risk the potential for public disclosure (inadvertent or through a Public Records Act request), which could in turn inhibit or distort competition in the secondary market. The secondary market for compliance instruments can and should be a robust and competitive market. Price disclosure could have a chilling effect on secondary market transactions. In this connection, a "liquid" secondary market is dependent on a large volume of trades. Requiring price disclosure for secondary market transactions would reduce liquidity and create conditions that would make price manipulation relatively more likely. The Staff seems to justify a price disclosure requirement for secondary market transactions based on a concern about price manipulation. In fact, a mandatory price disclosure requirement could lead to reduced liquidity, creating a greater potential for market manipulation.

In addition, some of the compliance instruments that will be purchased and sold in the secondary market represent "offsets," as well as allowances from jurisdictions (e.g., Quebec) with which the Cap and Trade program is "linked." There is a serious question whether the ARB can legally demand disclosure of prices agreed upon in transactions that occur outside California.

Finally, because the ARB does not regulate secondary market prices for compliance instruments, no legitimate purpose would be served by having the ARB demand price disclosure as a part of a transfer request. The ARB has a valid reason for requiring the disclosure of information regarding transaction dates, quantities and products transferred. Price, however, is not within the ARB's authority. Price disclosure should not be required. (SHELL 1)

Comment: It should be noted that many of the trades that represent transfers in and out of CITSS accounts are transactions which are subject to U.S. Commodity Futures Trading Commission reporting requirements. Given the role of ARB in these transactions, it is more appropriate that ARB utilize its current right to request the underlying contracts for the transactions should additional market monitoring information be desired. (SEMPRA 1)

Comment: GARB seems to be entering into an area that may be wholly or partially governed by the Commodity Futures Trading Commission (CFTC) rulemaking and/or the Securities and Exchange Commission related to a number of federal laws, including, for example, the Commodity Exchange, 7 U.S.C. 1, et seq., and the Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203 (2010), commonly referred to as the "Dodd-Frank Act" This may be especially true as GARB considers coordinating its Cap and Trade Program with provinces in Canada, such as the Canadian Province of Quebec. (LADWP 1)

Comment: ARB's rationale for proposing more detailed transaction reporting requirements, based on three different transaction types, is that doing so would provide ARB with more useful transaction data that could inform the marketplace.
IETA appreciates that ARB has listened to stakeholder feedback that the current one-size-fits-all approach to transaction reporting is not ideal, considering the different types of transactions that can occur. However, there are some further questions and concerns that IETA originally raised in our 2 August 2013 submission that we would like to point out again.

Generally, concern has been voiced amongst our membership that ARB may be wading into CFTC's jurisdiction in requiring that entities report on futures trades – particularly those falling under the third category of ARB's proposed list: "Exchange-Traded Contracts". Since CFTC already regulates these types of transactions, it seems redundant – and overly burdensome – that entities be required to report these transactions to ARB too. (IETA 1)

> **Response:** Staff is not attempting to regulate or approve prices of compliance instruments sold in secondary market transactions. The disclosure of compliance instrument information will help in maintaining market oversight and in detecting market manipulative activities. Requiring the mere disclosure of this information falls within ARB's authority to design, implement, and oversee the Cap-and-Trade Program.

H-4. Public Information Disclosure

CITTS User Terms

H-4.1. Comment: The CITSS user terms and conditions should protect confidential information from public disclosure, and should place liability with WCI, Inc. for the proper functioning of the CITSS web platform: As currently proposed in Appendix B of the Proposed Regulation Order, the CITSS User Terms and Conditions contain provisions that are inconsistent with industry standards for website reliability and the confidentiality of user information. SCE agrees that it is important to specify up front the terms and conditions under which participating entities agree to use the CITSS.

However, SCE objects to terms that risk the disclosure of confidential information and do not guarantee the reliability of the system; such terms may force participating entities to choose between obeying their risk policies governing the use of Internet platforms or complying with the cap-and-trade regulation, which provides for no alternative compliance mechanism outside of the CITSS.

In the ARB's current regulatory framework, CITSS is the only available mechanism for meeting compliance obligations. However, under Section 4.1 of the CITSS User Terms and Conditions, compliance entities are prohibited from seeking any legal damages against the ARB or WCI, Inc. arising from the failure of the CITSS platform. This is problematic, as it appears to insulate the ARB and WCI, Inc. from liability if the CITSS platform were to fail and prevent compliance entities from meeting their compliance obligations in a timely manner. Thus, if the ARB levied penalties against a compliance entity for failing to meet a compliance obligation by a mandated deadline, even if the failure was a direct result of the CITSS platform malfunctioning, that entity would have no recourse against the operator of the platform. The current industry standard for user agreements involving Internet platforms includes an availability guarantee on the part of the platform operator of 99% availability, or more. Not only does the ARB fail to make any such guarantee of the availability of the CITSS, it places the burden of economic harm on compliance entities in the event its Internet platform malfunctions. In order to better meet the applicable industry standard, the ARB should revise the liability provisions of the CITSS User Terms and Conditions to specify that WCI, Inc., as the creator and operator of the platform, will guarantee the availability of the CITSS platform to registered users at least 99% of the time, and that the ARB will postpone compliance deadlines in the event of a failure of the CISTS platform at any point during the 72-hour period preceding a compliance deadline. (SCE 1)

> **Response:** The contract requirements with the hosting provider stipulate that the CITSS should be available to users as much as reasonably practical, up to 24 hours a day. However, it may be necessary to schedule nightly or weekly down times for application maintenance. At a minimum, the application must be available no less than 18 hours per day with any scheduled downtime between 10pm and 4am Pacific Time. The CITSS has provided an overall availability of 99.56% since going live in August 2012. The lowest user availability recorded for any month of CITSS operations is 99.06% availability. Further, nearly all recorded "downtime" has been intentionally bringing the system offline for maintenance including systematic updates of security modules to stay ahead of evolving threats in the internet environment.

H-4.2. Multiple Comments: CITSS Content (Appendix B, 1.4): Issue: We are concerned with the following statement in Appendix B. Section 1.4 of the regulation:

> <u>"User understands that ARB will retain and use the Content consistent with the applicable regulation(s) and may disclose Content to the public to the extent the disclosure is required by California law or legal process, or to the extent that disclosure is not prohibited by California law."</u>

We have consistently expressed concerns over information submitted by program participants being made public. The proposed language in Appendix B is vague and subject to interpretation.

Recommendation: We suggest that ARB list in this appendix the information collected under this regulation that will not be disclosed to the public and that the disclosure is not required under California law. We are concerned that much of the confidential information provided in the CITSS registration may be deemed, wrongfully, to be public information under California law.

We strongly believe that almost all information submitted under CITSS should not be disclosed to the public. For example, we oppose sharing the names and IDs of our account representatives and account viewing agents registered in CITSS. The privacy right of these individuals should be protected. Additionally, net positions of individual entity or consolidated entities should not be made public as it could increase the potential for market manipulation and decrease overall market liquidity. (WSPA 1)

Comment: CITSS Content (Appendix B, 1.4): CLFP is concerned with the following statement in Appendix B. Section 1.4 of the regulation:

“User understands that ARB will retain and use the Content consistent with the applicable regulation(s) and may disclose Content to the public to the extent the disclosure is required by California law or legal process, or to the extent that disclosure is not prohibited by California law.”

CLFP is concerned over information submitted by program participants being made public. Overall, the proposed language in Appendix B is vague and subject to interpretation.

CLFP strongly believes that all information submitted under CITSS should be considered confidential and not be disclosed to the public, absent compelling reason and justification. We oppose sharing the names and IDs of account representatives and account viewing agents registered in CITSS. The privacy right of such individuals should be protected. (CLFP 1)

Comment: The proposed language of the CITSS User Terms and Conditions provides inadequate safeguards around confidential information stored on the CITSS web platform by compliance entities and other users of the site. For example, the Terms and Conditions state that the ARB “may disclose Content to the public to the extent the disclosure is … [not prohibited] by California law,” where Content is defined as “all information, data, text, or other materials that User provides to ARB or Western Climate Initiative (“WCI”), Inc. through use of CITSS.” The proposed language thereby gives the ARB the discretion to release holding and compliance account balances held by compliance entities or other participants to the public. The release of this market-sensitive information to the public without a significant lag time (i.e. after the end of a compliance period) could encourage manipulation of the allowance market, as the public could gain insight into compliance entities' bid strategies and take advantage of any entity with a short position near the end of a compliance period. (SCE 1)

> **Response:** Staff understands the concerns about information being made public. Staff is still deciding what information to release from the tracking system. Staff believes that balance is needed between the market's need for information and the protection of confidential business information. Staff notes that the user terms reflect what is already in CITSS, and that ARB has a long history of protecting confidential information pursuant to California law. As for how ARB treats confidential business information, existing section 95921(e) defines which information ARB will treat as confidential. ARB has extensive experience handling confidential business information along with the legal processes needed to protect that information.

H-4.3. Comment: Appendix B. Modifications to the CITSS user terms and agreement are needed: PG&E submits the following comments on the CITSS User Terms and Agreement for ARB's consideration. If it would be helpful, PG&E would be willing to provide an edited form of the agreement for ARB's consideration.

<u>Section 1.4</u>: PG&E requests ARB and WCI provide notice to PG&E prior to disclosure of the Content.

<u>Section 1.5</u>: PG&E requests ARB or WCI notify Users immediately of a breach of security on the CITSS system, including breach of stored information on data servers for the system.

<u>Section 2.3</u>: The entity using CITTS should receive written notice of a User's alleged violation and be offered an opportunity to correct the problem before the Agreement is terminated.

<u>Section 4.1</u>: PG&E recommends ARB and WCI introduce a limitation of liability provisions that protects the entity using CITTSS and its Users.

<u>Section 5</u>: This provision should be removed as it is duplicative of the restrictions in Section 2.2 (See Sections 2.2(b), 2.2(k) and 2.2(g)).

<u>Section 6</u>: The last sentence in this provision should be removed.

<u>Request for additional Provisions:</u>

- Add provision to inform Users of measures being taken to secure information processed or provided through the CITSS system.
- ARB and WCI's use of the Content should be restricted.

- WCI needs to provide warranties regarding its ability to perform the services, ensure data security, etc. (PGE 2)

  Response: Section 1.4: Staff understands the concerns about information being made public. Staff is still deciding what information to release from the tracking system, and this will be a future topic for discussion at future public workshops. Staff believes that balance is needed between the market's need for information and the protection of confidential business information. Staff notes that the user terms reflect what is already in CITSS, and that ARB has a long history of protecting confidential information pursuant to California law. As for how ARB treats confidential business information, existing section 95921(e) defines which information ARB will treat as confidential. ARB has extensive experience handling confidential business information along with the legal processes needed to protect that information.

  Section 1.5: Staff believes that language around notification of breach of security is not appropriate for inclusion in the regulation. Rather, it is an operational aspect of the system.

  Section 2.3: Termination of User's access gives ARB discretion to swiftly correct inappropriate User action. The commenter's recommendation would means that ARB would have to go through a drawn out process to terminate access, enabling the User to commit additional violations in the meantime.

  Section 4.1: ARB does not believe such a limitation is necessary at this time.

  Section 5: Staff understands the comments; however section 5 elaborates and emphasizes some of the clauses from section 2.2.

  Section 6: Staff does not understand why the commenter thinks the last sentence should be removed.

  Request for additional provisions: Disclosure of ARB's security measures could inadvertently inform the public of the ways to breach security, which ARB seeks to avoid at all costs. WCI and ARB are in privity of contract; any such warranties would be and are provided to ARB by WCI.

Account Balances

H-4.4. Multiple Comments: Releasing individual compliance account balances will unfairly expose compliance entities' sensitive position information: Consistent with its previous comments, SCE strongly opposes any release of individual CITSS account balances by the ARB. Releasing entity-specific compliance account balances would put covered entities at a competitive disadvantage because other market participants would be able to estimate their net positions, and could manipulate auction bidding behavior and market prices accordingly.

Recommendation: SCE continues to advocate for the release of aggregated compliance account holdings combined with compliance surrender information. To add clarity, SCE recommends that the ARB make the following change to Section 95921(e) of the cap-and-trade regulation:

The Executive Officer will protect confidential information to the extent permitted by law by ensuring that the accounts administrator: […]

(4) Releases aggregated information on the quantity ~~and serial numbers~~ of compliance instruments contained in all compliance accounts in a timely manner." (SCE 1)

Comment: The cap-and-trade regulations should be modified to clarify that release of entity-specific compliance account balances is not required, and ARB should only release aggregate compliance account data: SMUD has weighed in on the issue of compliance account balance disclosures twice in the past year, in comments for the initial information disclosure workshop on January 25, 2013, and comments on the June 25, 2013 workshop. SMUD understands the need for a balance between transparency and protection of market sensitive information in the Cap-and-Trade program. SMUD believes that a proper balance here is achieved without revealing entity-specific compliance account balances. Implicit in the ARB staff discussion of this issue is a continued assertion that entity-specific compliance account information is required to be released publicly by the current Cap-and-Trade regulations. SMUD continues to believe that the Cap-and-Trade regulations do not require release of entity-specific compliance account data in the first place, for reasons explained in our June 25th workshop comments. Accordingly, SMUD recommends that § 95921(e)(4) be modified as follows:

(4) Releases information on the aggregated quantity ~~and serial numbers~~ of compliance instruments contained in compliance accounts in a timely manner.

There are significant changes proposed to § 95921, implying that the section is open for the potential change as described above to be within scope for 15-day language. (SMUD 2)

Response: ARB did not propose any changes to section 95921(e) as part of this rulemaking. As such, the comments are outside the scope of the proposed changes to the regulation. However, to fully respond to the commenter's concerns, staff disagrees with the claims that releasing the information necessarily exposes the covered entities to manipulation. While ARB agrees the current text would allow ARB to release information on compliance instrument holdings in individual compliance accounts, ARB believes the existing language would also allow ARB to publish aggregated compliance account information. ARB intends to continue to explore this issue with stakeholders and no decision has been made on a level of aggregation to use. As for how ARB treats confidential business information, existing section 95921(e) defines which information ARB will treat as confidential. ARB has extensive experience handling confidential business information along with the legal processes needed to protect that information. ARB will continue to protect confidential information as required by, and fully consistent with, California law.

Auction Information

H-4.5. Multiple Comments: Additionally, the California Public Utility Commission ("CPUC") Matrix of Allowed Confidential Treatment Investor Owned Utility ("IOU") Data protects the IOUs' Net Open Position Information as confidential due to its market-sensitive nature. Position information stored in CITSS is clearly protected by regulations promulgated by another State agency.

The ARB should specify that any electric distribution utility disclosure required by the CPUC is permitted: SCE appreciates ARB's attempt to clarify disclosure prohibitions relating to auction information in Section 95914(c)(2)(D) of the Proposed Regulation Order. SCE recommends that ARB further modify this language to explicitly exempt electric distribution utilities' disclosure of such information when required to do so by the CPUC. Specifically, the Commission requires each utility to discuss procurement strategies and activities with its Procurement Review Group ("PRG"), which is comprised of participants who are subject to strict non-disclosure agreements.

Restricting the PRG's access to procurement-related information could jeopardize regulated utilities' cost recovery. Additionally, there should be no requirement for a utility to report each disclosure to the CPUC or its PRG to the ARB. The CPUC and PRG are entitled to all of SCE's procurement-related information, and it would be administratively burdensome to update the ARB prior to every such disclosure.

> **Recommendation:** To this end, SCE proposes the following changes to Section 95914(c)(2)(D) (throughout these comments, SCE's proposed changes are bolded to distinguish them from the ARB's proposed amendments): When the release is by an electric distribution utility of information regarding compliance instrument cost and other disclosures specifically required by the California Public Utilities Commission pursuant to any applicable rules, orders, or decisions. ~~In the event of a disclosure pursuant to this section, the electricity distribution utility must provide the specific statutory reference or to ARB that requires the disclosure of the information.~~ (SCE 1)

Comment: Section 95914. ARB Regulations Should Not Conflict with CPUC Requirements: The Proposed Regulation should be revised to be consistent with CPUC requirements concerning confidentiality and disclosure of GHG and electric procurement-related information in CPUC proceedings. PG&E proposes that ARB modify Section 95914(C)(2)(D) to recognize that investor owned utilities (IOUs) have a variety of procurement-related confidentiality and disclose obligations pursuant to CPUC statutes, rules, orders, or decisions.

For example, pursuant to Public Utilities Code Section 454.5(g) and Senate Bill (SB) 1488, the CPUC has adopted specific rules to protect the confidentiality of market sensitive information while at the same time allowing interested parties access to such information under strict confidentiality protocols and protective orders in formal CPUC proceedings for due process purposes. In addition, the CPUC has adopted protocols governing disclosures of similar market sensitive information concerning the procurement activities of electric and natural gas utilities to its Procurement Review Groups (PRG) pursuant to CPUC Decision 02-08-071. These disclosures are not expressly ordered by statute, but are required by CPUC orders and decisions. Moreover, CPUC Decision 12-04-046 orders IOUs to report all GHG compliance transactions at quarterly procurement review group meetings and in quarterly compliance reports. Prohibiting access by interested parties in CPUC proceedings or PRG access to GHG- related information under different confidentiality rules, or other disclosures required by the CPUC, could conflict with and violate the due process rights of interested parties and also jeopardize regulated entities' cost recovery. Further, the CPUC has recognized the need for consistency in the Confidentiality Protocols relating to GHG information, and recently requested consultation on such protocols among all interested parties, CPUC staff, and ARB staff as part of the CPUC's pending AB 32 GHG cost recovery proceedings. PG&E's proposed revisions to the ARB's regulations are intended to ensure consistency between the ARB's confidentiality rules and the CPUC's confidentiality rules.

Finally, ARB should not require a utility to report each disclosure that is required under the CPUC rules. For example, the PRO is entitled to all of PG&E's procurement related information and it would be administratively burdensome to update the ARB on each such disclosure.

> **Recommendation:** PG&E also proposes amending this section to clarify that natural gas utilities are protected under 95914(c)(2)(D):
>
> When the release is by an electric or <u>natural gas</u> distribution utility of information regarding compliance instrument cost and other disclosures specifically required <u>or authorized</u> by the California Public Utilities Commission <u>pursuant to any of its applicable rules, orders, or decisions.</u> ~~In the event of disclosure pursuant to this section, the electricity distribution utility must provide the specific statutory reference to ARB that requires the disclosure of the information.~~ (PGE 2)

Comment: Section 95914(c)(2)(D): Permitted disclosure of auction participation: Section 95914(c)(2)(D) should be modified so that the section applies not only to electric distribution utilities but also to other entities regulated by the CPUC that are compliance entities. The CPUC has not established an oversight process for natural gas suppliers but may use a structure similar to that of the electric distribution utilities.

Section 95914(c)(2)(D) should also be modified to acknowledge that the CPUC requires disclosure of information not only under specific statutory provisions but also under general orders and rulings pursuant to the authority conferred to the CPUC by the California Constitution and by statute. The modifications are as follows:

> Modification to Section 95914(c)(2)(D) (Auction participation and limitations): When the release is by ~~an electric distribution utility~~ an entity regulated by the California Public Utilities Commission of information regarding compliance instrument cost and other disclosures specifically required by the California Public Utilities Commission. In the event of a disclosure pursuant to this section, the ~~electricity distribution utility~~ entity regulated by the California Public Utilities Commission must provide the ~~specific~~ statutory or regulatory reference or the general order, decision or ruling to ARB that requires the disclosure of the information. (SEMPRA 2)
>
> **Response:** In response to these comments, staff made the following changes to Section 95914(c)(2)(D) as part of the 15-day amendments: When an entity (such as a privately owned utility that is regulated by a regulatory agency that has jurisdiction in the State of California discloses information related to bidding strategy to that regulatory agency or to a third party as authorized or required by the regulatory agency, that utility must provide to ARB the statutory or regulatory reference or general order, decision, or ruling that required the disclosure of the specific bidding strategy information. This reporting to ARB must be within 10 business days of the disclosure. This provision only applies to the categories of bidding strategy information contained in section 95914(c)(1), which are: intent to participate, or not participate at auction, auction approval status, and maintenance of continued auction approval; bidding strategy, bid price or bid quantity information; and information on the bid guarantee provided to the financial services administrator. The utility is not required to provide ARB with that information; rather, the utility must only provide ARB with the statutory or regulatory reference, or general order, decision, or ruling requiring the information disclosure.

H-4.6. Comment: Disclosure of auction-related information: proposed revisions properly clarify permissible disclosures of auction-related information under limited circumstances.

NCPA supports the language in new section 95914(c)(2)(C) of the Proposed Amendments recognizing that there are instances under which auction bidding information may be disclosed. This new section properly authorizes the release of information otherwise prohibited under 95914(c)(1) under the following conditions:

(A) When the release is to other members of a direct corporate association not subject to auction participation restriction or cancellation pursuant to section 95914(b),

(B) When the release is to an auction bid advisor whose activity has been disclosed to the Executive Officer pursuant to section 95914(c)(3).

(C) When the release is made by a publicly-owned utility only as required by public accountability rules, statute, or rules governing participation in generation projects operated by a Joint Powers Authority or other publicly-owned utilities.

(D) When the release is by an electric distribution utility of information regarding compliance instrument cost and other disclosures specifically required by the California Public Utilities Commission. In the event of a disclosure pursuant to this section, the electricity distribution utility must provide the specific statutory reference to ARB that requires the disclosure of the information.

These changes reflect certain clarifications and rationales set forth in Chapter 5 of the Regulatory Guidance Document,5 and are necessary to ensure that the Regulation do not inadvertently impede the ability of covered entities to comply with existing rules governing their ongoing contractual obligations. Including these distinctions in the Regulation also acknowledges the fact that disclosure of certain auction-related information amongst these related entities does not provide an unfair advantage to any one entity, nor does it enhance the likelihood of market manipulation. The Regulation is properly amended to allow for these limited exceptions to the restrictions on disclosure of auction-related information consistent with the Regulatory Guidance Document. (NCPA 1)

Response: Staff appreciates support for the proposed amendments.

H-4.7. Comment: Section 95914(c)(1): Non-disclosure of bidding information: The Proposed Regulation includes a new subsection Section 95914(c)(1)(A) that prohibits disclosure of "intent to participate at auction, auction approval status, [and] maintenance of continued auction approval." This provision is highly burdensome for regulated utilities because it entails extensive reporting and requires disclosure of substantial information filed confidentially at the CPUC. For compliance entities, disclosure of the information listed in Section 95914(c)(1)(A) would not harm market integrity because compliance entities are likely to participate in auctions to meet their compliance obligations. Knowledge of participation by compliance entities will not foster coordinated activities, contrary to statements made in the ISOR. The following requested modifications avoid coordinated activities without being overly burdensome.

Recommendation: Modification to Section 95914(c)(l) (auction participation and limitations):

Intent to participate at auction, auction approval status, maintenance of continued auction approval if a voluntary associated entity; (SEMPRA 2)

Response: Release of information in Section 95914(c)(1) could impart to other auction participants information about the demand for allowances (or diminished demand from entities that are not participating) at an upcoming auction. This would be particularly true of any large entities, including privately owned utilities or fuel suppliers that will be covered under the program beginning in 2015. Thus, staff declines to make the suggested change in the text to limit nondisclosure only to voluntary associated entities. Section 95914(c)(2)(D) allows disclosure by privately owned utilities pursuant to regulatory rules, orders or decisions, for information pertaining to compliance instrument cost, acquisition strategy and other disclosures.

H-4.8. Comment: Auction Participation Information:

§ 95914. Auction Participation and Limitations.…

(c) Non-disclosure of Bidding Information.…

(2) Auction participation information listed in section 95914(c)(1) may be released under the following conditions:…

<u>(E) When an entity is participating in an auction pursuant to conditions defined in a purchase and sale agreement with a third party, auction participation information may be disclosed by such auction participant to the third party if:</u>

<u>1. The auction participant and the third party contractually ensure against either party transferring information to any other party, or coordinating the bidding strategy among other participants;</u>

<u>2. The third party neither participates in the auction, nor enters into a similar purchase and sale agreement for the same auction with any other market participant;</u>

<u>3. The auction participant informs ARB of the existence of the contract, identifies the third party and the auction to which the agreement applies, provides the third party's contact information, and provides an attestation by the Primary Account Representative of the entity of the completeness of the disclosure; and</u>

<u>4. The auction participant must provide to the Executive Officer in writing at least 15 days prior to an auction, the following information:</u>

<u>a. Names of all of the third parties participating in the Cap-and-Trade Program with which the auction participant has contracted to purchase allowances in the auction;</u>

b. Description of the agreements pursuant to which the auction participant is purchasing allowances at auction for future delivery to other third parties; and

c. Confirmation that the auction participant is not transferring to or otherwise sharing auction participation information with other auction participants. (CHEVRON 2)

Response: The current nondisclosure provisions allow third parties, whether they have or do not have a contract with another auction participant, to participate in auctions without the restriction on auction participation in the proposed language. In addition, such third party contracts are permissible without any information on the entity's participation at an upcoming auction since any allowance delivery specified in the contract may be satisfied by auction participation, secondary market transactions or both. Staff appreciates the suggested addition to the regulatory text, however, staff believes the suggested changes are not necessary.

Other

H-4.9. Comment: Jurisdiction of California (S96022(c), pg. 338): ARB has proposed language in 96022(c): "A party that has rights and protections under the Foreign Sovereign Immunities Act consents to civil enforcement of the laws, rules and regulations pertaining to this article in California's courts, subject to the rights and protections afforded to entities subject to the Foreign Sovereign Immunities Act, including removal to federal court."

Recommendation: Strike or revise this language to make it clear that an entity that is subject to another jurisdiction linked to the California program cannot be tried in either California or U.S. Federal court (if the entity is a non-US entity). The proposed language would make it possible to try the entity in both California and in the linked jurisdiction. (WSPA 1)

Response: As stated in the Initial Statement of Reasons, this provision was added to ensure that rights held by entities pursuant to the Foreign Sovereign Immunities Act are not being abrogated by the regulation. Entities participating in the California program are subject to the requirements in California; those participating in a linked jurisdiction would be subject to those requirements. The recommendation by the commenter mistakes the purpose of the regulatory provision and the rights available under the Foreign Sovereign Immunities Act. As such, staff declines to make the requested change.

I. COST CONTAINMENT

I-1. Proposed Additional Cost Containment Mechanisms

I-1.1. Multiple Comments: Recommendations: If additional cost-containment measures are needed in future, consider sectoral-based offsets if approved to replenish the APCR rather than a hard price cap.

If additional or alternative cost containment provisions continue to be considered, maintaining the environmental integrity of the program remains of the utmost importance and any new changes should be implemented such that disruption to the program, and to market player expectations, is minimal, given the importance of regulatory certainty to the program's success.

Although we are aware of the possibility that even with the suite of cost containment features already built into the program, external or otherwise improbable circumstances may transpire that cause program costs to rise beyond expected price ranges, those market conditions are unlikely to occur. Rather, based on our analysis of the market conditions and cost containment features in AB32 cap-and-trade regulation as well as lessons derived from other cap-and-trade programs, features currently embedded in the program make it highly unlikely that allowance prices will escalate towards the extreme scenarios where experts are concerned that political pressure could force programmatic modification.

In 2011, EDF conducted economic modeling that found, as designed, there is an 85% chance that the price containment reserve will not be needed at all, and that even if needed, it is highly unlikely the reserve would ever be exhausted. Even if only half of allowable offsets are available, we estimated that there is only a 1/10 of a percent chance that prices would rise above $40 per ton.

CARB's own modeling predicts that the current program design will result in the environmental goals being met at low cost. It is only under unlikely sensitivity scenarios where either offsets are limited or complimentary measures achieve significantly less reductions than anticipated, that additional cost containment measures could be needed. Another analysis from Severin Borenstein of UC Berkeley and EMAC shows that the probability is small of triggering and exhausting the allowance reserve (APCR) – and in fact, it is much more likely that prices remain low: at or near the price floor. Another reason we expect allowance prices to remain in check stems from examples provided by other trading programs such as the European Union Emissions Trading System (EU ETS), the Regional Greenhouse Gas Initiative, and the U.S. Acid Rain program. Allowances prices have been much lower than expected in these programs; emission reductions have occurred faster and more cheaply than many thought possible prior to the program start. We expect the same to be true for California's program – a product of a well- designed market based regulation.

Two additional considerations CARB should take into account with respect to the proposed cost containment mechanism involve the post-2020 program. First, if these future allowances are in fact borrowed, it should not impact the stringency of the longer term cap – and any borrowed credits must be deducted from the economy wide cap. Second, if emission reductions are borrowed from future compliance periods past 2020, interest should be required (particularly for those of vintages father into the future) and additional credits should be surrendered at some point in the future. Interest on borrowing was envisioned as part of the House-passed Waxman- Markey cap and trade legislation in 2009 (at an 8% interest rate for allowances borrowed several years into the future).

Potential for Future Additional Cost-Containment Measures: Although EDF supports the proposed regulatory modification for cost containment because it maintains the same overall quantity of allowances in the program, we understand that some will argue that it might not be sufficient to contain costs - especially if unexpected market conditions occur such that prices stay high for sustained periods of time. Again, such a situation seems highly unlikely due to the cap and trade program's numerous existing cost containment features. This new provision will further serve to contain costs while maintaining the environmental integrity of the program, which is of the utmost importance.

Because there is the option to refill the APCR with allowances borrowed from future vintage years, there is a relative certainty that the APCR will not be fully utilized over the next several years. This should provide California ample opportunity to consider if any other cost containment measures are needed and feasible to protect the program as we approach 2020. EDF believes that there are two alternatives which are much more desirable from the perspective of environmental integrity than a hard price cap: 1) extending the cap-and-trade program beyond 2020 which would allow for greater borrowing as needed and 2) refilling the APCR as needed with offsets, including sector-based international offsets.

We understand that neither of these additional options for cost containment is available at this time and that both would require significant further policy development. Specifically, with regard to refilling the APCR with international sector-based offsets, EDF would not support this measure until California had considered the environmental rigor of these offsets and had adopted a protocol pursuant to current California law. However, based on findings by the REDD Offsets Working Group (ROW), EDF believes there is a strong possibility that sector-based offsets like REDD (Reducing Emissions from Deforestation and Forest Degradation) may have a role to play in California's cap-and-trade program as envisioned by the current regulation. Furthermore, existing progress in Acre, Brazil, suggests that REDD credits likely will not face the supply constraints that domestic offset are projected to have. EDF would only support refilling the APCR with offsets if they were sold at the APCR rate rather than the market rate. California could then consider how to use the price premium to further meet the objectives of AB 32. (EDF 1)

Comment. In closing, I want to strongly commend the language in the resolution today that asks the Executive Officer to begin working on post 2020 cap and trade along with cost containment. This is an essential piece in maximizing the overall economic and environmental benefits of this historic program. (EDF 2)

> **Response:** Board Resolution 12-51 directed ARB to develop a proposal for cost containment mechanism that would achieve the policy objective of ensuring the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program. The proposed additional cost containment mechanism does not create any additional allowances and ensure the cap, and the environmental integrity, of the program is upheld. Through Resolution 13-44, the Board directed ARB to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment to address market certainty.
>
> ARB staff is committed to exploring all options to address long-term issues pertaining to cost containment within the scope of AB 32. ARB staff is committed to developing offset protocols that fit the requirements of AB 32 in sufficient supply for offsets to be available to satisfy up to eight percent of the compliance obligation of covered entities. In additional to the proposed mine methane capture protocol, a methane rice cultivation protocol is also being developed. ARB staff looks forward to working with stakeholders and researchers to identify and bring to fruition additional offset protocols.

I-1.2. Comment: A robust portfolio of cost containment measures will serve to reduce price volatility and provide true cost containment, satisfying board resolution 12-51: SCE supports the cost containment proposal offered by the Joint Utilities Group. That proposal established three categories of cost containment measures: (1) measures to take effect immediately; (2) measures that would be triggered when the market moves closer to the highest APCR price; and (3) an approach to address compliance instrument availability when the APCR is exhausted. SCE's recommendations for each of these three categories of cost containment measures are described in more detail below.

1. Measures That Would Take Effect Now: SCE recommends that the ARB adopt certain measures that would take effect now. These measures would – over time – reduce the likelihood of prices rising above the APCR in the future by: (1) reducing demand for compliance instruments; (2) increasing the supply of compliance instruments; and (3) ensuring that compliance instruments are accessible in the marketplace. Specifically, SCE suggests that the ARB: d) Address constraints imposed by the current holding limit; e) Hold an additional auction after the end of each compliance period. The ARB should redistribute allowances between auctions to allow for one additional auction per compliance period, and/or acquire more allowances for auction. This auction should be held between September 1 of the year following the end of a compliance period, when verification statements for prior-year emissions are due, and November 1, when compliance entities are required to demonstrate compliance.

2. Measures that would be triggered when the market approaches the highest APCR price: SCE recommends that the ARB adopt certain measures that, when triggered, would quickly alter compliance instrument demand/supply dynamics and constrain upward pressure on market prices for a period of time. Borrowing of allowances is included in this category. One example of a trigger is a percentage level of depletion of the APCR. Specifically, SCE suggests that the ARB adopt the following proposals: b) Compliance Account Proposal: When the trigger is reached, the ARB could allow covered entities to transfer surplus allowances from their compliance accounts to their limited use holding accounts. This would allow entities that have built up a bank of excess allowances to re-inject those allowances in the market, which will improve market liquidity; c) Limited Borrowing Proposal: When the trigger is reached, the ARB could allow covered entities to surrender current-year vintage allowances and next-year vintage allowances to meet their compliance obligations for the previous year (not applicable post-2020).

3. Measures that would keep prices at the third tier of the APCR when the APCR is exhausted: SCE recommends that the ARB adopt certain measures that, when triggered, would keep allowance prices at the third tier of the APCR regardless of current demand, while still preserving the environmental integrity of the cap-and-trade program over time. Upon depletion of the highest tier of the APCR, the Executive Officer should make available (through the APCR sale mechanism) additional allowances, in excess of the cap, necessary to satisfy the demand of compliance or opt-in compliance entities at the price set for the highest tier of the APCR in the relevant year. The Executive Officer could then use the funds raised by the sale of these additional allowances to ensure greenhouse gas ("GHG") reductions equal to or larger than the number of additional allowances sold. For example, the Executive Officer could: b) Commission a third party to purchase and retire allowances from emissions trading programs outside of California and linked jurisdictions; d) Mandate emission reductions in sectors not covered by the California cap- and-trade regulation. (SCE 1)

> **Response:** Thank you for your detailed comment. There are many features that have been incorporated into the design of the Cap-and-Trade Program to address allowance price uncertainty and increase compliance flexibility while ensuring that emission goals are achieved. ARB staff appreciates your suggestions but feels the existing cost containment features and the additional proposed cost containment mechanism are sufficient to satisfy the Board direction through Resolution 12-51 that the allowance price not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions.
>
> To address allowances prices in the event of unanticipated conditions, the Board, through Resolution 13-44, has directed ARB staff to develop a plan for the post-2020 Cap-and-Trade Program including cost containment. ARB staff will be assessing all feasible options, including those mentioned in your comment, and will return to the Board will recommendations by the start of the third compliance

period. ARB staff looks forward to working with stakeholders and researchers to ensure that the post-2020 Cap-and-Trade Program design is robust and durable to all potential economic conditions.

I-1.3. Comment: Resolution 12-51 directed ARB staff to examine several parts of the Cap-and-Trade program for cost containment. While this work may have taken place internally, it is important for ARB to present its findings to stakeholders along with potential amendments to or justifications for the program's status quo. Additionally, CCEEB recommends that ARB incorporate the "Three Key Elements of Cost Containment" as described by the Joint Utility Group (JUG). The three elements include:

A) Measures that take effect now to reduce the likelihood of prices rising above the Allowance Price Containment Reserve (APCR) by: 1) reducing demand for compliance instruments; 2) increasing the supply of compliance instruments; and 3) ensuring that compliance instruments are accessible in the marketplace.
B) Measures that, when triggered, would quickly alter compliance instrument demand/supply dynamics and constrain upward pressure on market prices for a period of time. An example trigger is a percentage level of depletion of the APCR.
C) Measures that, when triggered, would keep allowance prices at the third tier of the APCR regardless of current demand, while preserving the environmental integrity of the Cap-and-Trade Program over time.

Implementation of the JUG recommendations should address many of the directions to staff from Resolution 12-51 and will provide certainty that there are mechanisms in place to avoid prices reaching third tier costs of the APCR. (CCEEB 1)

Response: Thank you for the comment. ARB staff examined various aspects of the Cap-and-Trade Program to identify additional cost containment mechanisms in response to Resolution 12-51. Five potential options for an additional cost containment mechanism were presented at the June 25 public workshop on compliance retirement, market-related reporting, and cost containment.

Pursuant to Board Resolution 13-44, ARB staff will continue to work with the stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional provisions for long-term cost containment. ARB staff looks forward to continued engagement on these issues to ensure that the long-term program design is robust and durable.

I-1.4. Comment: We agree with stakeholders that ARB should, to the extent possible, clarify ex ante the procedures it will employ to address future market contingencies. However, as members of the Emissions Market Assessment Committee (EMAC) have noted, in the unlikely event allowance prices reach the highest tier of the Reserve, it will not happen overnight. Early signs of the market conditions required to trigger such a perfect storm would be known years in advance, providing ARB ample opportunity to assess and propose additional safeguards through its existing regulatory process. (NRDC 2)

> **Response:** ARB staff is confident that the proposed cost containment provision adequately addresses the concerns raised in Resolution 12-51 that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions. ARB staff has also acknowledged that there is a small probability that unanticipated conditions will arise necessitating additional cost containment provisions.
>
> The Board has addressed this issue through Resolution 13-44, where the Board directed ARB staff to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment, prior to the third compliance period. ARB staff is committed to working stakeholders and researchers to exploring all feasible options to ensure that the Board direction is met, both in the near- and long-term.

I-1.5. Comment: WSPA supports the proposed amendments to address short-term allowance cost containment in order to address market volatility and its ultimate impact on the California economy. However, WSPA encourages ARB to take further steps in the regulation to address longer term potential imbalances between supply and demand for allowances.

WSPA believes that the proposed regulation needs additional measures to address potential long term imbalances to allowance supply and demand and potential adverse economic impacts. An analysis of such measures and potential economic impacts would be responsive to Board Resolution 12-51.

In addition, we support expanding offsets, changing holding limits, and limited borrowing policy options described in the Joint Utility Group Cost Containment Proposals as presented in the June 25, 2013 workshop (see Attachment A).

Exposure to the high costs in the final tiers of the APCR and market volatility will ultimately lead to emissions and jobs leakage as companies struggle under carbon costs higher than those which are workable in the relevant geographical markets.

Recommendation: WSPA suggests that ARB establish a mechanism by which it could provide new additional allowances to the market to prevent costs from exceeding the highest cost in the APCR, as required by Board Resolution 12-51.

WSPA encourages ARB to extend the 100% assistance factor through the third compliance period and to include in its evaluation economic and legislative reports, such as the 2012

Legislative Analyst Office (LAO) study on carbon markets, which states that the environmental goals of AB32 would not be compromised by giving free allowances to industry, as the gradual lowering of the emissions cap would still drive CO2 reductions. (WSPA 1)

Response: Thank you for the support of the cost containment proposal. ARB staff agrees that the proposed mechanism satisfies the Board directive in Resolution 12-51 over a range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. In response to Board Resolution 13-44, ARB staff will work with stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional cost containment provisions to ensure that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve.

In the current regulatory amendments, ARB staff has proposed to extend the first compliance period assistance factor through the second compliance period. There are currently two external analyses underway to re-evaluate the leakage classification of industrial sources. The results of these studies are expected to inform the transition assistance for industrial sources in future periods and will be complete prior to the start of the third compliance period.

I-1.6. Comment: ARB Should Develop a Robust Cost Containment Mechanism: In order for the cap and trade program to meet AB 32's legislative mandate, it must be implemented in a cost effective manner. Board Resolution 12-51 recognized the potential for prices to rise to an unacceptably high level and instructs staff to develop a mechanism to ensure that prices do not rise above the third tier of the allowance price containment reserve (APCR). While Chevron supports borrowing as a mechanism to reduce price volatility, the borrowing mechanism in the proposed amendments does not ensure that prices will not rise above the APCR price. As a result, the borrowing approach may not fully satisfy the Board Resolution.

Chevron supports the cost containment approach presented by the Joint Utilities Group at the July 18, 2013 workshop which proposed, among other things, expanding offsets, changing holding limits, and limited borrowing. We are convinced that actions taken today to limit costs will benefit the environmental goals of the program by reducing the chance of leakage and protecting jobs and the California economy. (CHEVRON 2)

Response: Thank you for the comment. ARB staff agrees that the proposed mechanism satisfies the Board directive in Resolution 12-51 over a range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. In response to Board Resolution 13-44, ARB staff will work with the stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional cost containment provisions to ensure that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve. ARB staff is committed to exploring all options to address long-term issues pertaining to cost containment within the scope of AB 32, including those outlined by Joint Utilities Group.

I-1.7. Comment: To meet the resolution, the ARB should adopt additional measures to constitute a suite of cost containment measures.

A. Provide additional allowances at the highest Reserve price: The June 25, 2013 ARB paper entitled "Policy Options for Cost Containment in Response to Board Resolution 12-51" ("ARB Paper")8 outlines in section 3.1 a cost containment option that would provide unlimited additional allowances at the highest price tier of the Reserve. This appears to be the only feasible option presented to date that would ensure that allowance prices will not exceed the highest price tier of the Reserve.

This option should be adopted. The usual Reserve rules would apply, with sales to covered entities only and allowances placed directly in compliance accounts. There does not appear to be any reason to restrict availability of these additional allowances to the final Reserve sale each year or each compliance period. Instead, the additional allowances should be available at each Reserve sale. Covered entities will only purchase allowances at the highest price tier of the Reserve when no other cheaper compliance instruments are available. Making the additional allowances available at each Reserve sale, not just the September sale, would help prevent prices being driven to extremes during the twelve months between each September Reserve sale. The holding limit should apply to these allowances, as there does not appear to be any rationale for different rules to apply.

B. Maintain environmental integrity by procuring additional emission reductions within California: The Resolution directs ARB staff to propose measures that contain costs "while minimizing the impact on existing allowances and maintaining the environmental objectives of the program." Therefore, if additional allowances are issued as discussed above, additional emission reductions must be achieved to maintain the environmental integrity of the cap-and- trade program as a whole. There are many ways in which this may be done.

Option 4.3 in the ARB Paper, "Mandate additional emission reductions from California sources," is an option that should be considered. This option is likely to be the most consistent with the current legislative directions about the use of the State's cap and trade revenue, including revenue from the sale of additional Reserve allowances. It may provide a useful part of the solution.

C. Additional measures should be taken to reduce the likelihood of resorting to the above cost containment mechanisms: In addition to adopting the approach set out in sections XI.A and XI.B above as the only feasible ways to ensure the Resolution is met, the ARB should consider further cost containment mechanisms to help avoid, delay, or reduce the need to obtain compensating emission reductions. These measures fall into two categories, both of which are important:

1) Measures that would take effect now and gradually over time reduce the likelihood of prices rising above the Reserve in the future by reducing demand for compliance instruments, increasing the supply of compliance instruments, and ensuring that compliance instruments are accessible in the marketplace.

2) Measures that, when triggered, would quickly alter compliance instrument demand/supply dynamics and constrain upward pressure on market prices for a period of time to address short-term price spikes. A possible trigger is the percentage level of depletion of the Reserve.

For the first category of cost containment measures, the proposals by the Joint Utilities in the paper presented at the June 25, 2013 workshop include:

- Approve more offset protocols to increase the supply of offsets.
- Exempt offsets from projects within California from the 8 percent offset limit.
- Allow each covered entity to carry over any unused portion of its 8 percent offset limit to use for future compliance.
- Address constraints imposed by the current holding limit.

For the second category of cost containment measures, in addition to the mechanism currently proposed in section 95913(f)(5), measures proposed by the Joint Utilities include:

- Unused offset proposal: The ARB would track the number of offsets used for compliance (cumulatively) compared to the number of offsets that would have been used if every covered entity exhausted its 8 percent limit. The difference between the two numbers would be the “8 percent offset shortfall.” Each covered entity would be given the option to register through the tracking system to receive a proportional share of the 8 percent offset shortfall if the trigger is reached. The registration process ensures that only the entities that are interested in procuring additional offsets are given the ability to do so. Entities that do not register would remain subject to the 8% limit. When the trigger is reached, the ARB would distribute rights to use additional offsets among the registered entities up to the 8 percent offset shortfall in total. The new offset limits for those entities would be calculated to ensure that, if all registered entities surrender offsets up to the new higher level, the 8 percent offset shortfall would be used up but not exceeded. If the 8 percent offset shortfall is not exhausted in that compliance period, a new offset level would be calculated for the registered entities for the next compliance period.
- Compliance account proposal: When the trigger is reached, allow covered entities the flexibility to transfer surplus allowances from their compliance account to their limited use holding account. This allows entities that have built up a bank of allowances in excess of their compliance needs to re-inject those allowances into the market.

- Limited borrowing proposal: When the trigger is reached, allow covered entities to surrender for compliance allowances with vintages of the current year and the following year.
- Offset geographic scope proposal: When the trigger is reached, increase the number of compliance-grade offsets by expanding the geographic scope of the approved offset protocols to North America.
- Offset project start date proposal: When the trigger is reached, increase the number of compliance-grade offsets by changing the Offset Project Commencement date in sections 95973(a)(2)(B) and (c) of the Regulation to an earlier date.

SCPPA recommends that several (or all) measures from each of category one and category two be adopted to complement the key cost containment mechanisms. (SCPPA 1)

> **Response:** Thank you for the comment. ARB staff considered all five cost containment options presented in the June 25, 2013 workshop. The preferred cost containment provision was chosen based upon the ability to achieve the Board direction in Resolution 12-51 within the framework of AB 32. ARB staff is confident that the proposed cost containment provision adequately addresses the concerns raised in Resolution 12-51 that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions. However, ARB staff has also acknowledged that there is an extremely small probability that unanticipated conditions will arise necessitating additional cost containment provisions.
>
> The Board has addressed this issue through Resolution 13-44, where the Board directed ARB staff to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment, prior to the third compliance period. ARB staff is committed to working with stakeholders and researchers to exploring all feasible options, including those presented by the Joint Utilities Group, to ensure that the Board direction is met, both in the near- and long-term.

I-1.8. Comment: Sections 95870 and 95913. PG&E Supports Staff's Cost Containment Proposal and Encourages Staff To Continue Exploring Additional Mechanisms To Satisfy The Board Resolution.

PG&E Recommendations: PG&E appreciates the Board's direction contained in Resolution 12-51 and commends staff for engaging stakeholders and expe11s in an open and transparent dialogue about how to satisfy the Board Resolution. PG&E would like to see the Board direct staff to continue efforts with stakeholders in 2014 to complete the task of establishing the highest price tier of the APCR as an auction price ceiling effective under all market scenarios. PG&E further recommends that the Emissions Market Assessment Committee (EMAC) be charged with tracking this market for indications of price run-ups and be offered the option to petition the Board for timely and effective action, if needed.

PG&E recommends the scope of this continued work include a price ceiling for California Cap- and-Trade allowance auctions that will effectively maintain prices at or below the highest price tier of the APCR under any circumstance and at any time, regardless of future allowance budgets and the expected duration of the program. PG&E recommends the timeline allow for this price ceiling mechanism to be designed, approved, and incorporated into the Cap-and-Trade Regulation no later than the beginning of the second compliance period, January 1, 2015.

Need For a Clear Price Ceiling As Soon As Possible: PG&E maintains that an auction price ceiling would improve the Cap-and-Trade program and could be implemented in a manner that preserves the environmental integrity of the program. The written and oral comments shared by ARB staff, market experts, and other stakeholders at the June 25,2013 workshop support developing an auction price ceiling. The price floor has proven to be an effective tool and a corresponding price ceiling is needed to ensure that the Cap- and-Trade program is neither vulnerable to market manipulation nor undermined by unacceptably high allowance prices.

Linkage is widely regarded as the means to achieve needed emissions reductions on a global scale. A program with an admitted vulnerability to unstable high prices will give prospective partners pause. Addressing this issue before opportunities for additional linkages arise will be easier and will instill confidence in other jurisdictions that a larger Cap-and-Trade program will be successful. The size of California's Cap-and-Trade market alone will expand dramatically in 2015 when natural gas suppliers and transportation fuel distributors come under the cap. It would be prudent to address the market vulnerability of extreme price increases in advance of any further market expansion.

PG&E supports the staff cost containment proposal contained in the draft regulation as an effective addition to address short-lived price increases in the Cap-and-Trade market. However, this mechanism cannot ensure prices will not exceed the third tier Allowance Price Containment Reserve (APCR) price, as Board Resolution12-51 requires. Staff concedes this point in the Initial Statement of Reasons that accompanied the 45-day language: "However, if unanticipated conditions create a long-term and persistent increase in the demand for allowances through 2020, the proposal may not be sufficient to fill all accepted bids at the highest price tier. Under these circumstances, the proposal would not ensure that allowance prices do not exceed the Reserve top tier price."' Staff also acknowledges that "the effectiveness of the staff proposal is reduced as the program approaches 2020." Furthermore, borrowing from future allowance budgets without an auction price ceiling, may have the unintended consequence of increasing prices to unacceptable levels in later years when combined with the incremental reductions in the cap and increased possibility of economic recovery. PG&E therefore urges ARB to provide stakeholders with a specific plan and accelerated timeline for addressing "the policy objective of ensuring that allowance prices will not exceed the highest price tier of the [APCR]" (Board Resolution12-51) in response to persistent structural market imbalances.

Potential for APCR to be Exhausted and Likely Consequence: PG&E points to the results of the EMAC's analysis,' which demonstrates there is a "non-trivial possibility" that auction prices could reach unacceptably high levels due to a systemic imbalance in market fundamentals in the 2013 to 2020 timeframe. The study's conclusion warns "that there might be the potential for non-competitive activities by some market participants that could artificially inflate or depress the price."

Staffs current proposal allows for limited borrowing, but does not allow for the increase of overall allowance supply to address unexpected increases in allowance demand. Therefore, Staffs proposal cannot prevent the market from reaching unacceptably high prices in a reasonable range of plausible conditions during the period of2013 to 2020. Leaving the market without fi1m protection against prices increasing above the third tier of the APCR would expose the market to significant risks. This circumstance would pose a real and significant obstacle to the on-going successful operation of the program and could force compliance entities to choose between paying excessive allowance prices or facing non-compliance penalties.

PG&E believes the EMAC study referenced above is a credible study that has anticipated unacceptably high-priced market conditions and that it would be inadvisable not to be adequately prepared. As Severin Borenstein, member of the EMAC, wrote in his September 30, 2013 blog, "While the proposed changes are a small step in the right direction, they don't go far enough to address the fundamental risk to the market from a surge in emissions that could cause the price of allowances to skyrocket." (PGE 2)

> **Response:** ARB staff is confident that the proposed cost containment provision adequately addresses the concerns raised in Resolution 12-51 that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions. ARB staff has also acknowledged that there is a small probability that unanticipated conditions will arise necessitating additional cost containment provisions.
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> The Board has addressed this issue through Resolution 13-44, where the Board directed ARB staff to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment, prior to the third compliance period. ARB staff is committed to working with stakeholders and researchers to exploring all feasible options to ensure that the Board direction is met, both in the near- and long-term.

I-1.9. Comment: To avoid these abrupt actions, to avoid CARB losing control of the solution, to stay within the requirements of both AB32 and the Board Resolution, and to increase the potential that problems are avoided in the first place rather than fixed after they happen – there are numerous, relatively simple design measures that CARB can put in place. We believe it is possible to design additional cost containment into the system by working with the current design of the system – without the need to add on additional, complex and controversial design elements. These fixes include:

- Remove or greatly increase holding limits for regulated parties
- Allow use of allowance vintages from within the year in which the compliance obligation is due – not in which it is calculated (BP 1)

  Response: There has been no analysis to suggest that altering the holding limits or use of alternate vintages for compliance would be an appropriate response to Board resolution 12-51 which directed ARB staff to propose additional cost containment provisions to ensure that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve (APCR).

I-1.10. Comment: IETA encourages ARB to re-visit the proposals originally discussed at the 25 June 2013 Public Workshop (including those by ARB, EMAC, and the Joint Utilities Group2), which explored a number of innovative options that would serve to keep prices below the highest-tier APCR price, while at the same time maintain environmental integrity.

We appreciate that some of these options would take much more work to determine how they could be implemented, both technically and legally. The timeframe with which ARB had to work with for this rule-making session may not be adequate to fully explore all the possibilities. However, IETA would be pleased to work with ARB to continue to explore the plausibility of going beyond this first proposed option to address cost containment.

In particular, IETA considers the following option presented at the 25 June 2013 workshop to be worth further consideration:

Sourcing allowances from third party greenhouse gas reduction programs: If faced with an extreme case where keeping prices below the highest tier of the APCR was proving difficult, ARB could have a provision ready to kick in that allowed the creation of additional allowances to be sold at the highest tier price, providing crucial cost relief.

In order to maintain environmental integrity, the state of California could use revenue from the sale of these additional allowances to buy and then retire quantifiable and certified allowances from third party greenhouse gas reduction programs (such as the Regional Greenhouse Gas Initiative (RGGI)). Meaning that for each additional California Carbon Allowance (CCA) that ARB created and sold, a corresponding RGGI allowance would be retired. California could even choose to implement a quota system where for each additional CCA it created it would retire (for example) three RGGI allowances.

Not only would such a system provide cost relief and maintain environmental integrity, it would also serve to indirectly link its market to other markets – a goal outlined in AB32 to build regional and international markets.

Admittedly, developing such a provision would require much more research into various technical and legal procedures, but IETA encourages ARB to continue to explore the possibility. IETA would be pleased to work with ARB moving forward in this pursuit. (IETA 1)

> **Response:** Thank you for the comment. ARB staff considered all five cost containment options presented in the June 25, 2013 workshop. The preferred cost containment provision was chosen based upon the ability to achieve the Board direction in Resolution 12-51 within the framework of AB 32. Linking the California Cap-and-Trade Program to other emissions trading systems is a priority and ARB staff is currently active in continuing to foster relationships with potential domestic and international jurisdictions. However, ARB staff determined that recognizing emission reductions achieved through non-linked jurisdictions was not an appropriate response to Resolution12-51. ARB staff is confident that the proposed cost containment provision adequately addresses the concerns raised in Resolution 12-51 that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions. However, ARB staff has also acknowledged that there is a small probability that unanticipated conditions will arise necessitating additional cost containment provisions.
>
> The Board has addressed this issue through Resolution 13-44, where the Board directed ARB staff to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment, prior to the third compliance period. ARB staff is committed to working with stakeholders and researchers to exploring all feasible options, including those involving recognition of compliance instruments from external emissions trading systems, to ensure that the Board direction is met, both in the near- and long-term.

I-1.11. Comment: SMUD believes that to achieve the goals of the Board Resolution, the ARB should include additional cost limitation provisions in the 2013 Cap-and-Trade update. In addressing the Board Resolution, ARB staff has focused only on a measure that would be triggered once a price crisis is already happening. A broader reading of the Board's Resolution would embrace provisions that would help to prevent the price crisis from happening in the first place. The ARB should add provisions in 15-day language adjustments to the Proposed Regulation Order to further address cost containment, drawing from all three program elements mentioned in the Joint Utilities' white paper provided as part of the cost-containment workshop. The proposed limited borrowing from future vintages at the highest price APCR level, in limited circumstances, is not sufficient, in SMUD's view, to achieve the Board's goals.

Hence, SMUD suggests that ARB revisit the basic structure of the Joint Utilities proposal, with the three main categories of cost containment measures, and include additional Cap-and-Trade modifications from these categories:

A) Measures that take effect now and gradually over time to reduce the likelihood of prices rising above the APCR in the future by: 1) reducing demand for compliance instruments; 2) increasing the supply of compliance instruments; and 3) ensuring that compliance instruments are accessible in the marketplace.

B) Measures that, when triggered, would quickly alter compliance instrument demand/supply dynamics and constrain upward pressure on market prices for a period of time. An example trigger is a percentage level of depletion of the APCR.

C) Measures that, when triggered, would keep allowance prices at the third tier of the APCR regardless of current demand, while preserving the environmental integrity of the Cap-and-Trade Program over time.

SMUD contends that the limited borrowing measure in the Proposed Regulation Order is essentially from Category B above – it would quickly alter compliance instrument supply and demand dynamics for a period of time, and is triggered when the APCR is essentially 100% depleted. While ARB staff's proposed cost-containment changes include a couple of minor measures from Category A, they do not at all include a measure that is from Category C. SMUD believes that a Category C measure is necessary to truly ensure the price cap that is envisioned in the Board's resolution.

SMUD recommends that ARB include additional Category A and B measures in the 2013 Cap-and-Trade amendments, while signaling that a Category C measure that would fully meet the intent of the Board's resolution is being further examined. The Category C signal would come from the Board directing staff in a resolution to undertake a specific analysis that would:

1) Define a maximum demand/minimum supply scenario that assumes robust economic growth, reduced efficacy of GHG reduction measures in place; and sharp limits on the amounts of offsets available to the market;

2) Estimate how many additional allowances would be necessary in that scenario to ensure, per Resolution 12-51, that allowance prices "…will not exceed the highest price Tier of the Allowance Price Containment Reserve…"; and

3) Identify and confirm the existence of sufficient emission reductions outside the Cap that would be available to fully offset that estimated amount of additional allowances, along with describing viable mechanisms for quickly accessing these commensurate emission reductions.

With respect to additional Category A and B measures, SMUD suggests that the ARB include, but not limit consideration to, the following additional measures:

1) Measures to ensure that the allowed 8% of compliance from offsets is fully available to the market, by:

- Avoiding the loss of this potential if entities do not use their full offset allocation, allowing carryover of the offset limit on an entity-specific basis or by spreading unused amounts over the broader market.
- Quickly pursuing and adopting new, rigorous offset protocols, and expanding the geographic scope of existing protocols. SMUD has seen market analysis indicating that even with eventual adoption of the proposed new protocol for mine methane capture, and future consideration of adoption of a protocol related to rice cultivation, offset supply (given the current geographic scope of the offset protocols in place) will not be sufficient to provide the full "room" under the 8% offset limit. SMUD encourages the quick adoption of the proposed coal mine methane protocol and refocused effort on developing and adopting additional protocols; including REDD+ protocols. SMUD also recommends consideration of expanding existing protocols to all of North America and beyond if feasible (SMUD notes that geographic expansion to North America is allowed under the Cap-and-Trade regulations without a new rulemaking).

2) Measures that will act to reduce demand for compliance instruments over the long term. For example, the ARB could pursue measures that fostered greater electrification of energy uses currently associated with distributed fuel use in California. Such electrification, if expanded beyond a baseline amount, would act to reduce demand for allowances because the reduction in emissions on the distributed fuel side would be greater than the increase in emissions on the electricity side. This electrification requires investments in infrastructure, outreach to consumers, and potential changes in policies to recognize the energy and GHG benefits fully. The ARB should consider how the Cap-and-Trade structure can be modified to reflect the long-term reduction in compliance instrument demand that come with greater electrification of distributed fuel sources. Presently, the Cap- and-Trade structure acts as a disincentive for this path, as electrification means an additional compliance obligation for the electric utility obligated entity, with nothing in place to reflect the reduced Cap-and-Trade obligation of a distributed fuel provider, or to reflect the overall decrease in compliance instrument demand.

3) Measures that would act to increase supply of compliance instruments over the long term. For example, the ARB could exempt from the offset limit any offsets that provide in-state ancillary environmental benefits similar to actual reductions at capped sector facilities. One way to structure this would be to exempt offsets from the 8% limit if they could prove one or more of the following:

- a direct reduction or avoidance of any criteria air pollutant in California;
- a direct reduction or avoidance any impacts on water quality in California;
- a direct alleviation of a local nuisance within California associated with the emission of odors;
- direct environmental improvements to land uses and practices in

California's agricultural sector;

- direct environmental improvements to California's natural forest resources and other natural resources;
- a direct reduction of the need for mitigation of the impacts within California of rising global greenhouse gas emissions.

4) Additional limited borrowing, but triggered earlier than that proposed in the Proposed Regulation Order, where the sole cost-containment measure is triggered when the APCR is essentially fully depleted. SMUD contends that the ARB should include measures that are triggered earlier than the full depletion of the APCR, in order to gain time to avoid the more severe price crisis. The "door" to consideration of limited borrowing has been cracked ajar by the ARB's proposed cost-containment measure in the Proposed Regulation Order. SMUD reiterates that the ARB should adopt a provision that when 40% of the allowances in the APCR have been purchased, entities are allowed to use allowances for compliance from the next vintage year. An extra year's worth of eligible compliance instruments in the market pulls supply of allowances temporarily back into a better balance with demand, providing time for technology or other measures to reduce demand in the following year and beyond. (SMUD 2)

Response: Thank you for the comment. ARB staff considered many options for an additional cost containment mechanism (or mechanisms) in response to Board Resolution 12-51. ARB staff presented five of the most feasible options in the June 25, 2013 workshop. The preferred cost containment provision was chosen based upon the ability to achieve the Board direction in Resolution 12-51 within the framework of AB 32 and the ability to be implemented in a timely manner. ARB staff is confident that the proposed cost containment provision adequately addresses the concerns raised in Resolution 12-51 that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions. However, ARB staff has also acknowledged that there is a small probability that unanticipated conditions will arise necessitating additional cost containment provisions.

The Board has addressed this issue through Resolution 13-44, where the Board directed ARB staff to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment, prior to the third compliance period. ARB staff is committed to working with stakeholders and researchers to explore all feasible options, including those presented by the Joint Utilities Group, to ensure that the Board direction is met, both in the near- and long-term.

Given the Board direction in Resolution 13-44, the proposed cost containment provision was not open during the 15 day comment period and therefore there will be no additional alterations to the proposal during the current regulatory amendments.

I-1.12. Comment: The Joint Utilities appreciate the Board's direction contained in Resolution 12-51 and commend staff for engaging stakeholders and experts in an open dialogue about how to satisfy the Board Resolution. However, the staff's proposal alone does not satisfy Board Resolution 12-51 and, therefore, should only be considered as one aspect of a larger cost containment package yet to be finalized.

The Joint Utilities agree with the three essential elements of Board Resolution 12-51 that must be satisfied to create a comprehensive cost containment solution.

1. Ensure that allowance prices will not exceed the highest price tier of the Allowance Price Containment Reserve (APCR)

In the Initial Statement of Reasons that accompanied the 45-day language, Staff states that "if unanticipated conditions create a long-term and persistent increase in the demand for allowances… the proposal would not ensure that allowance prices do not exceed the Reserve top tier price."

The Joint Utilities also point to the EMAC analysis, which demonstrates there is a "non-trivial possibility" that auction prices could reach unacceptably high levels due to a systemic imbalance in market fundamentals. The study's conclusion warns "that there might be the potential for non-competitive activities by some market participants that could artificially inflate or depress the price."

2. Maintain the environmental objectives of the program

The Joint Utilities maintain that there are reasonable options available for eliminating the risk of extremely high auction prices that maintain the environmental integrity of the program. Many of these options were presented by market experts and stakeholders in the June 25, 2013 workshop (including the Joint Utilities Group).

The Joint Utilities agree that no solution would be complete if it didn't preserve the environmental integrity of the Cap-and-Trade structure.

3. Assure effectiveness during the period of 2013-2020

As 2013 is already coming to a close, it seems clear that staff's plans to implement a solution that ensures allowances prices remain reasonable will not be effective in the early part of the 2013-2020 period. Severin Borenstein, member of the EMAC, wrote in his September 30, 2013 blog, "[w]hile the proposed changes are a small step in the right direction, they don't go far enough to address the fundamental risk to the market from a surge in emissions that could cause the price of allowances to skyrocket." Delay in establishing a solid protection against prices increasing above the third tier of the APCR prolongs the market exposure to significant risks.

The Joint Utilities feel greater urgency is required to address the risks of unacceptably high cap- and-trade allowance prices in the 2014 to 2020 timeframe. (JUC)

Response: Thank you for the comment. With Board approval at the April 25, 2014 Hearing, the proposed cost containment provision will be in place prior to the start of the second compliance period and prior to the first scheduled surrender of compliance instruments. Through Resolution 13-44, ARB staff will address any additional issues related to cost containment through the development of the post-2020 Cap-and-Trade Program prior to the third compliance period. ARB staff understands that market certainty is an important component of a well-functioning market. If, prior to the third compliance period, new analyses or changing market conditions highlight the need for additional cost containment provisions, ARB staff will address any concerns in a timely manner to provide market and regulatory certainty.

I-1.13. Comment: Auction purchase limit: Calpine strongly supports and appreciates CARB's proposed revisions regarding the auction purchase limit. The Proposed Amendments would increase the covered entity auction purchase limit to 20 percent (%) through 2014 and 25% thereafter. This would provide the largest covered entities assurance that they can obtain all they need to fulfill their compliance obligation and afford them some of the same flexibility afforded to other covered entities with respect to their procurement decisions. Calpine therefore urges the Board to adopt the proposed revisions to the auction purchase limit and direct staff to finalize these revisions at the earliest opportunity, so they will apply to all auctions occurring in 2014.

The Board should adopt the proposed revisions to the auction purchase limit and they should be finalized at the earliest opportunity: Calpine strongly supports the Proposed Amendments to the auction purchase limit. We greatly appreciate this important step CARB staff has taken in fulfillment of the Board's direction to assure that the largest covered entities are afforded the same flexibilities as other market participants under the Regulation. We urge the Board to adopt the Proposed Amendments' increase to the auction purchase limit as soon as possible so that the increase will apply to all auctions occurring in 2014.

Under the Regulation, the current vintage auction purchase limit for covered entities is 15% of the allowances offered for auction at each auction occurring in 2013 and 2014. The corresponding limit on purchases from the advance auctions conducted during the same period is 25%. There is no limit currently specified for auctions occurring after 2014. The Proposed Amendments would (1) increase the current vintage auction purchase limit applicable to covered entities to 20% through 2014 and (2) establish a new auction purchase limit applicable to covered entities and electrical distribution utilities for auctions conducted from January 1, 2015 through December 31, 2020 of 25% of the allowances offered for auction, for both the current vintage and advance auctions.

As one of the largest covered entities in California, Calpine will have one of the largest compliance obligations during the first compliance period. In addition, Calpine recently commissioned two highly efficient combined-cycle power plants in the San Francisco Bay Area.

In light of the size of Calpine and its compliance obligation during the first compliance period, we greatly appreciate the increase to 20% for auctions conducted during 2014. This increase will assure that Calpine should be able to procure all the allowances it needs during the quarterly auctions conducted in 2014. We therefore urge the Board to adopt the proposed changes to section 95911(d)(4) and encourage CARB to finalize them as soon as possible, so they will be effective for all auctions occurring in 2014. Should the amendments not be final prior to the 2014 auctions, we look forward to working with CARB staff to assure that the existing auction purchase limit does not act as a bar to procurement of Calpine's needs in the quarterly auctions.

We also believe that imposition of a 25% auction purchase limit for auctions conducted after 2014 should provide sufficient flexibility for all covered entities to obtain allowances needed to comply from the quarterly auctions. We assume that the 25% limit is intended to apply separately to allowances from the current vintage auction and the advance (future vintage) auction and would recommend that CARB clarify this upon finalizing the Proposed Amendments by making the following minor amendment to section 95911(d)(5):

§ 95911. Format for Auction of California GHG Allowances.…

(d) Auction Purchase Limit.

(5) The auction purchase limit for auctions conducted from January 1, 2015 through December 31, 2020 will be 25 percent of the allowances offered for auction <u>in each Current Auction and Advance Auction </u>for covered entities, opt-in entities, and electrical distribution utilities or group of covered entities, opt-in entities, and electrical distribution utilities with a direct corporate association pursuant to section 95833. (CALPINE 1)

Response: In response to this comment, staff proposed 15-day changes to section 95911(d)(5) to reflect Calpine's comment. In addition, staff proposed regulatory modifications during the 15-day comment period during which the current vintage auction purchase limit was changed to twenty percent for covered entities and opt-in covered entities for the last auction in 2014.

I-1.14. Comment: The cost containment mechanism should be revisited in subsequent rulemaking documents to include additional provisions that will remove restrictions on offset usage and not draw on future vintage allowances;

The ARB should continue to evaluate provisions for a more robust cost containment proposal: The September 4th Amendments would revise Section 95913(f)(5) to create a new cost- containment mechanism, wherein the ARB would draw on the latest vintage of allowances in the event that the highest price tier of the Allowance Price Containment Reserve (APCR) is exhausted. While TID supports the integration of new cost-containment mechanisms, we do not believe that the proposed revisions to Section

95913(f)(5) satisfy the Board's directive in Resolution 12-51. TID encourages the ARB to continue to evaluate additional cost-containment mechanisms through 15 day language amendments.

Resolution 12-51 requires staff to develop a cost containment proposal that meets all of the following objectives: (1) The proposal must achieve the policy objective of ensuring that allowance prices will not exceed the highest price tier of the APCR; (2) the proposal must minimize the impact on existing allowances; (3) the proposal must maintain the environmental objectives of the program; and (4) the proposal must demonstrate that the proposed mechanisms are effective in a reasonable range of plausible combinations of conditions as needed to assure their effectiveness during the period of 2013 to 2020.

The proposal does not meet all of the requirements in Resolution 12-51. Specifically, the proposed changes do not account for the conditions where the mechanism in Section 95913(f)(5) is needed in more than one year. If prices get to $50, they will likely remain at that level for a sustained period. The September 4th Amendments recommend that if the highest price tier is depleted in more than one year, then the ARB would pull allowances from the previous compliance period (i.e., 2020 allowances would be used first, then 2019, and finally 2018). Consequently, the mechanism in Section 95913(f)(5) could not be used for more than three years during any triennial Compliance Period because in 2018 there would be no future compliance period from which the ARB could borrow allowances. This mechanism clearly does not "minimize the impact on existing allowances" because future allowances would be depleted, which would in turn put further upward pressure on allowance prices. The proposed mechanism addresses the need for price containment for a limited period, but exacerbates the price conditions in the later years of the program.

In addition, TID is concerned that if the ARB borrows allowances from the future to keep the prices down, then in the future, we will have higher prices. Anyone can buy allowances in the forward market for future vintage allowances. If the ARB pulls allowances from the future, that will immediately drive up the prices for future vintage allowances. If such a mechanism were used, then the ARB would penalize an entity that seeks to plan ahead. Utilities routinely hedge risks by transacting in forward markets, and shortening the forward market limits that ability.

In order to best satisfy the direction of Resolution 12-51, TID believes that staff should continue to evaluate cost containment mechanisms through further amendments to the Cap-and-Trade Regulation. For example, the ARB could simply create an unlimited number of allowances at the $50 price, which would be available only through the Allowance Price Containment Reserve. The policy argument against this approach in the past is that it sacrifices the environmental integrity of the cap, so called "printing" of allowances. Access to the APCR is limited to compliance entities, so while there are more allowances are in play, none of the allowances made available under this scenario would be in circulation. The measure would simply serve as a safety valve, and would not increase the number of allowances in circulation and available to the market, therby retaining the integrity of the cap. The ARB should also evaluate liberalization of offset rules as discussed in the next section of these comments. (TID 1)

> **Response:** As detailed in the Staff Report, available at http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf, the proposed cost containment mechanism makes an additional 206.7 million allowances eligible for sale through the Allowance Price Containment Reserve (APCR). These allowances represent ten percent of the allowance budget each year after the APCR has been populated and are not limited to the allowances designated for Advance Auction.
>
> ARB staff is confident that the proposed cost containment provision adequately addresses the concerns raised in Resolution 12-51 that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve over a range of plausible conditions. ARB staff has also acknowledged that there is a small probability that unanticipated conditions will arise necessitating additional cost containment provisions.
>
> The Board has addressed this issue through Resolution 13-44, where the Board directed ARB staff to develop a plan for a post-2020 Cap-and-Trade Program, including cost containment, prior to the third compliance period. ARB staff is committed to working with stakeholders and researchers to exploring all feasible options, including issues related to offsets, to ensure that the Board direction is met, both in the near- and long-term.

I-1.15. Comment: CLFP supports the proposed amendments to address short-term allowance cost containment in order to address market volatility and its ultimate impact on the California economy. However, CLFP encourages ARB to take further steps in the regulation to address longer term potential imbalances between supply and demand for allowances.

CLFP believes that the proposed regulation needs additional measures to address potential long term imbalances to allowance supply and demand given the potential for future adverse economic impacts.

Exposure to the high costs in the final tiers of the Allowance Price Containment Reserve (APCR) and market volatility will ultimately lead to emissions and jobs leakage as companies struggle under carbon costs higher than those which are workable in the relevant geographical markets.

> **Recommendation:** CLFP makes the following recommendations:
>
> - ARB should establish a mechanism by which it could provide new additional allowances to the market to prevent costs from exceeding the highest cost in the Allowance Price Containment Reserve.

Finally, CLFP encourages ARB to extend the 100% assistance factor through the third compliance period and to include in its evaluation economic and legislative reports, such as the 2012 Legislative Analyst Office (LAO) study on carbon markets, which states that the environmental goals of AB32 would not be compromised by giving free allowances to industry, as the gradual lowering of the emissions cap would still drive CO2 reductions. (CLFP 1)

> **Response:** Thank you for the support of the cost containment proposal. ARB staff agrees that the proposed mechanism satisfies the Board directive in Resolution 12-51 over a range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. In response to Board Resolution 13-44, ARB staff will work with stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional cost containment provisions to ensure that the Board direction is met, both in the near- and long-term.
>
> In the current regulatory amendments, ARB staff has proposed to extend the first compliance period assistance factor through the second compliance period. There are currently two external analyses underway to re-evaluate the leakage classification of industrial sources. The results of these studies are expected to inform the transition assistance for industrial sources in future periods and will be complete prior to the start of the third compliance period.

I-1.16. Comment: The cost containment provisions should address long-term demand and supply imbalance: SDG&E and SoCalGas support the changes in the Proposed Regulation providing additional protections from short-run price fluctuations of compliance instruments. However, the Proposed Regulation does not include changes to address long-term demand and supply imbalance and as such does not comply with ARB's direction in Resolution 12-51. To comply with ARB's direction to "ensure that allowance prices do not exceed the highest price tier of the Allowance Price Containment Reserve," ARB should place a price cap on the auctions before triennial surrenders. If an imbalance occurs, then additional measures to ensure environmental integrity can be instituted using the funds from the sale of allowances from the Price Containment Reserve and the Cap-and- Trade Investment fund. SDG&E and SoCalGas therefore propose the following change to Section 95913(h)(1)(B).

Modification to Section 95913(h)(l)(B) (sale of allowances from the allowance price containment reserve): Pursuant to section 95913(f), the Reserve sale immediately preceding the compliance obligation instrument surrender on November 1 will continue until all accepted highest price tier bids are filled ~~or the allowances made available pursuant to section 95870(j)(1) are sold pursuant to section 95913(f).~~ (SEMPRA 2)

> **Response:** Thank you for the comment. Section 95913(h)(1)(B) as written is integral to ensuring the environmental objectives of the program a necessary condition in Board Resolution 12-51. Therefore it will not be removed for the regulation.

ARB staff is confident that the proposed mechanism satisfies the Board directive to ensure that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. In response to Board Resolution 13-44, ARB staff will work with stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional cost containment provisions to ensure the near- and long-term stability of the program.

I-1.17. Comment: SDG&E and SoCalGas would also like to reiterate the request in their previous comments that ARB address cost containment, eliminate jurisdictional conflicts, delete requirements that are overly burdensome and unnecessary for further efficient market monitoring, and make other changes to provide consistency and clarity in the Proposed Regulation. (SEMPRA 2)

Response: The comment does not specify any specific changes, but staff does appreciate the commenter's request for clarity. Staff believes that cost containment and market monitoring provisions as amended in the 15-day changes are clear and will provide for efficient market monitoring.

I-1.18. Comment: On cost containment, the resolution directs the creation of a plan for cap and trade post-2020. We think this is a great idea. We believe cost containment should be a pivotal part of that plan. We urge that proposal be amended slightly so that the staff and the Executive Director can begin working on that right away and not wait until the third compliance period. There are planning issues and, indeed, the acknowledgement that the proposal for cost containment as set forth in the regulation to be adopted today doesn't address long-term price spikes, and these kinds of matters should be addressed immediately. So we hope that post 2020 plan can be developed sooner rather than later. (NCPA 2)

Response: ARB staff is in agreement that finalizing the design of the post-2020 Cap-and Trade Program, including any cost containment provisions, is critical to providing incentives to long-term investments and market certainty. Providing early market signals is important, but so is prudent and thoughtful program design. ARB staff will work with stakeholders and researchers to design the post-2020 program in a timely manner and will return to the Board prior to the third compliance period when the design has been thoroughly vetted and through the formal regulatory process.

I-1.19. Comment: We also request clarification on how any withheld allowances will be recirculated into the market to avoid price strikes. (GUG)

Response: The proposed cost containment provision is presented in detail in the ARB Staff Report, available at http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf. The proposed cost containment mechanism makes an additional 206.7 million allowances eligible for sale through the Allowance Price Containment Reserve (APCR). These allowances would be available for purchase by covered entities at the APCR sale immediately preceding the compliance obligation each year. Any allowances purchased through an APCR sale are subject to the holding limit and placed directly into the compliance account of an entity where they are available immediately for compliance.

Knowing that allowances will be available from the Reserve, covered entities will have no incentive to purchase allowances at any price higher than the highest price tier. Thus, maintaining the availability of a sufficient supply of allowances to satisfy demand at the Reserve sale will be effective in ensuring that allowances prices do not exceed the highest price tier.

I-1.20. Comment: I also note in the Resolution and we support the direction to develop a cost containment plan. But we feel that 2018 would be too late. So we encourage that that plan be developed earlier in the second compliance period. So thank you very much for the opportunity to present these comments. And we look forward to continuing to work with staff to make the cap and trade program a success. Thank you. (SCGE)

Response: ARB staff is in agreement that finalizing the design of the post-2020 Cap-and Trade Program, including any cost containment provisions, is critical to providing incentives to long-term investments and market certainty. Providing early market signals is important, but so is prudent and thoughtful program design. ARB staff will work with stakeholders and researchers to design the post-2020 program in a timely manner and will return to the Board prior to the third compliance period when the design has been thoroughly vetted and through the formal regulatory process.

I-1.21. Comment: I also want to encourage staff to continue efforts to address cost containment goals established by the Board in Resolution 1251. We absolutely support the cost containment measure that has been proposed to date. We don't think that it's complete. We don't think it's efficient. And we encourage the staff to continue to work on that. As I said, there are a number of other comments that are included in our written comments that I'll leave up to staff to review. I wanted to, however, just congratulate staff on the mine methane protocol and offer our support for that protocol. It's a appropriate the Board reviews this protocol along with dialog and cost containment. All of the economic forecasts that have been used in developing the rules and the processes here for the Cap and Trade Program included the full provision of offsets in terms of the forecasting for the price. (SCE 3)

Response: ARB staff is confident that the proposed mechanism satisfies the Board directive to ensure that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. In response to Board Resolution 13-44, ARB staff will work with stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional cost containment provisions to ensure the near- and long-term stability of the program.

I-1.22. Comment: I would say probably the most important I think, well, for a number of us, certainly for Pacific Gas and Electric is cost containment. The staff's resolution on cost containment gets it right. Staff admitted that they haven't gone far enough on developing cost containment. We're concerned about APCR in the out years. But solving that in the out years doesn't do anybody any good in terms of reducing angst. If that could be approached sooner rather than later and we would propose bring it back to the Board in January of 2015. That's the beginning of the second compliance period. That's when we all have concern about how the next round of cap and trade begins to look. We urge the Board to put that date, January 2015, into the resolution. I think that's most of it. (PGE 3)

Response: ARB staff will return to the Board by the beginning of the third compliance period with the design of the post-2020 Cap-and-Trade Program including any additional cost containment provisions. If, prior to the third compliance period, new analyses or changing market conditions highlight the need for additional cost containment provisions, ARB staff will address any concerns in a timely manner. ARB staff does not believe that any additional cost containment provisions are required prior to January 2015.

I-1.23. Comment: First, SCPPA appreciates a proposed provision that would make additional allowances available through the allowance price containment reserve if there were a short-term price spike. However, the new provision would not be sufficient to contain allowance prices if there were a long-term supply/demand imbalance. More work needs to be done. (SCPPA 3)

Response: ARB staff is confident that the proposed mechanism satisfies the Board directive to ensure that the allowance price does not exceed the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. In response to Board Resolution 13-44, ARB staff will work with stakeholders and researchers to design the post-2020 Cap-and-Trade Program including additional cost containment provisions to ensure the near- and long-term stability of the program.

I-1.24. Comment: Secondly, we would like to offer some support -- a lot of support for cost containment measures. The cost containment measures that are considered will go a long way towards addressing our concerns regarding potential high prices in the short term. We agree with many of the other companies that have stated that we do think that cost containment measures should be considered earlier than 2018. And we trust that we will be able to work through and figure out really a better way to address cost containment in the long term. (CHEVRON 3)

> **Response:** ARB staff will return to the Board by the beginning of the third compliance period with the design of the post-2020 Cap-and-Trade Program including any additional cost containment provisions. If, prior to the third compliance period, new analyses or changing market conditions highlight the need for additional cost containment provisions, ARB staff will address any concerns in a timely manner. ARB staff does not believe at this time that any additional cost containment provisions are required prior to the start of the third compliance period.

I-2. Evaluation of Proposal

I-2.1. Comment: Recommendation: Adopt staff's proposal to borrow a limited number of allowances as needed to refill the APCR.

On the issue of cost containment in California's cap and trade program, we'd first like to emphasize – as we have in previous letters to CARB and to the Emissions Market Assessment Committee (EMAC) – that the program currently includes an array of well-designed cost containment provisions. Nevertheless, we understand CARB's interest in considering additional options given concerns over potential suspension of the program if prices rise unexpectedly high. To this end, we support CARB's proposed regulatory change to allow borrowing of allowances from future vintage years at the highest price tier of the Allowance Price Containment Reserve. The proposal will help address price concerns, while still ensuring that the overall environmental integrity of the program remains intact.

Importance of maintaining a steady program and existing cost containment provisions: As effectively laid out in CARB's June 25, 2013 paper, California's cap-and-trade program currently includes numerous cost-containment features including provisions for allowance banking, multiyear compliance periods, a broad program scope, an auction price floor, emissions offsets, administrative allocation of allowances, direct complimentary regulations that reduce emissions in capped sectors and an allowance price containment reserve (APCR).

Proposed regulatory change to allow borrowed allowances to replenish the Allowance Price Containment Reserve and the importance of maintaining environmental integrity: While we believe additional price containment measures are unnecessary, we understand that there are concerns over unexpectedly high prices, and a push towards including additional cost containment provisions. As outlined in the July 2013

Discussion Draft and July 18th Workshop presentation, CARB's proposal would make available an additional source of allowances for the Allowance Price Containment Reserve. Starting in 2015, 10% of future vintage allowances would be made available at the highest price tier of the Reserve if needed to satisfy demand.

These allowances would first be drawn from the latest vintage(s) (furthest in the future) – 2020, then 2019, etc as the regulation currently stands. Further, the regulatory change as written would automatically allow for borrowing from even later periods once new future emission reduction targets are put in place.

Generally speaking, allowing for increased borrowing as a cost containment measure is aligned with provisions included in the EU-ETS as well as with cost containment provisions suggested by EDF (as alternatives to a price cap) for California's program in previous letters. The provision as proposed to allow borrowing to replenish the Reserve has several advantages to other options like hard price caps.

First, the proposal places high priority on ensuring the environmental integrity of the program (as directed by the Board's Resolution) by maintaining its core feature: the hard declining cap. While this provision allows for additional allowances in particular years if needed, by replenishing the Reserve with borrowed allowances, it ensures the same cumulative limit on emissions defined by the cap over the length of the program.

Second, by allowing borrowing only at the highest price tier of the APCR, the proposal ensures that this provision is used only when absolutely needed – during conditions of unusually high price spikes or unexpected market conditions.

Of course, there is an inherent tradeoff associated with allowing for increased borrowing since while it can help contain costs in the years when borrowed allowances are used, it increases the stringency of the cap in future years, which may mean pushing higher prices (and emission reductions) down the road. However, this particular provision allows for increased borrowing only at the highest price tier of the Reserve (making it unlikely that these allowances would be used) and further, it allows for borrowing of only 10% of each future year's allowances, reasonably limiting the extent to which future years' cap stringency would be increased. Further, as we approach these future years (2015-2020), we hope that a post-2020 program will be put in place, making borrowing from even later years possible. In other words, this provision provides important regulatory certainty early on even as it anticipates and remains flexible to potential extension of the program. (EDF 1)

> **Response:** Thank you for the comment and your support of the proposed cost containment provision.

I-2.2. Comment: The proposed increases to the APCR supply is a good first step but is not sufficiently responsive to board resolution 12-51: SCE supports the approach that staff has identified for borrowing allowances, but borrowing allowances is not a long-term cost containment mechanism and does not satisfy board resolution 12-51.

SCE supports the proposal to facilitate allowance borrowing from future compliance years to fill the third tier of the ACPR for cost containment purposes. Such an approach can act to moderate short-term price fluctuations and help promote a more smoothly functioning allowance market. Utilizing the APCR ensures that only regulated compliance entities will be able to procure borrowed allowances from future compliance years and that borrowed allowances are used directly for compliance. Additionally, borrowing allowances first from the most distant vintage year in circulation allows the allowance market the greatest amount of time to address price volatility.

However, as a stand-alone proposal, this borrowing mechanism is insufficient to provide assurance to the market that allowance prices will not rise above the highest price tier of the APCR, and therefore does not satisfy Board Resolution 12-51.

Resolution 12-51 directs staff to develop mechanisms to ensure that allowance prices do not exceed the highest price of the APCR. The approach included in the Proposed Regulation Order provides no such assurance. Borrowing is important to reduce short-term price volatility, but under a stress-case scenario where demand for allowances exceeds supply for a prolonged period of time, the APCR could be exhausted, which could cause prices to exceed the highest APCR tier price. The Proposed Regulation Order states that if the quantity of accepted bids at the highest price tier of the APCR exceeds the available allowances, including any allowances that have been borrowed from future vintage years, the reserve sale administrator will distribute the available allowances among bidders on a pro-rated basis, causing each bidder to receive fewer allowances than its original bid. In this scenario, if compliance entities are not able to procure all of the allowances they need for compliance at the price of the highest tier of the APCR, it is reasonable to assume that prices in the secondary market would move higher than that price level as well. (SCE 1)

> **Response:** ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 over a reasonable range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB staff will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

I-2.3. Comment: Cost containment: We support staff’s proposal to backfill the Allowance Price Containment Reserve (Reserve) with future vintage allowances designated for auction should demand for Reserve allowances outstrip existing supply. The proposal comports with the Board’s direction in Resolution 12-51 to provide additional certainty that allowances prices do not exceed the highest price-tier of the

Reserve while maintaining the environmental integrity of the program. We ask the Board to support staff's proposal and reject cost-containment proposals that do not safeguard the integrity of the cap.

We support staff's proposal to make future vintage allowances designated for auction available for purchase by covered entities at the highest price tier of the Reserve in the extreme event that the Reserve's supply is exhausted.

In Resolution 12-51, the Board directed staff to adopt an additional cost containment mechanism to achieve two primary objectives: (1) ensure prices do not exceed the highest tier of the Reserve and (2) maintain the environmental integrity of the program. The Board's direction was narrowly tailored to address the contingency that allowance prices reach and exceed the 'soft price ceiling' built into the rule. As staff notes, the current program already contains a bevy of cost-containment mechanisms designed to prevent this very occurrence, including multiyear compliance periods, unlimited banking, limited use of offsets, an allowance reserve, and generous provision of emission allowances at no cost.

Accordingly, we strongly support staff's proposal insofar as it is designed to apply only if allowance prices reach the highest price tier and the Reserve's current supply is depleted. (NRDC 2)

> **Response:** Thank you for the comment and support of the proposed cost containment provision.

I-2.4. Comment: 10% Allowances Set Aside for Reserve Auction: Proposed section 95870(b)(1) states that 10% of the allowances from budget years 2015-2020 will be eligible to be sold pursuant to section 95913 (f). This appears to be a typographical error because 95913 (f) is the allowance price containment reserve auction. If 10% of the allowances are withheld for the reserve auction, it could significantly impact the availability of allowances for the advance auction. This typographical error is also in 95870(i)(1).

Recommendation: Modify 95870(b)(1) to state "…will be eligible to be sold pursuant to section 95910 (c)(2)." Modify 95870(b)(2) to state "….not sold pursuant to section 95910 (c)(2) will be auctioned pursuant to Section 95911 (f)(3)(D)"

S95870(i)(1) states that beginning in 2015, 10% of all remaining allowances from each vintage will be sold pursuant to Section 95913 (f), which is the reserve auction.

Recommendation: Modify 95870(i)(1) to state "… to be sold pursuant to section 95910 (c)(2)" , which is the advance auction. (WSPA 1)

> **Response:** Section 95870(b)(1) and section 95870(i)(1) (previously erroneously identified as section 95870(j)(1)) have been modified as part of the proposed cost containment mechanism in response to Board Resolution 12-51. The

modifications allow for ten percent of allowances from all budget years to be eligible to be used to fill bids at the highest price tier of the Allowance Price Containment Reserve at the Reserve Sale immediately preceding the compliance obligation. There are no errors in the text and a more detailed description of the proposed mechanism is available in the ARB Staff Report available at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf.

I-2.5. Comment: Allowance Price Containment Reserve (pg. 181) [Additional Allowances for Cost Containment]: ARB has proposed language in 95913(f)(5) that has multiple references to sections that do not exist. For example, in Section (E): "The allowances defined in section 95870(j)(1) will be sold beginning with the latest vintage and then the preceding vintages, from latest to most recent, until all accepted bids at the highest price tier are filled or until all the allowances defined in section 95870(j)(1) have been sold." Reference is made to 95870(j) which does not exist in the modified or original regulation. If ARB is citing currently proposed regulatory language, it should be clearly noted.

It seems like the intent of this section is to make additional allowances available at the highest tier of the reserve sale, if there is more demand for allowances at the highest tier than allowances available for sale. Section 95870(j) is missing, which is necessary to interpret and comment on section 95913(f)(5).

This approach does not provide "additional" allowances; it merely creates the potential for a shortage of allowances in later years and a concomitant price spike in allowances.

Recommendation: Delete this requirement. In lieu of the proposed regulation ARB should evaluate whether and to what extent longer-term potential imbalances exist between allowance supply and demand. WSPA suggests that CARB's evaluation include economic and legislative reports and that CARB establish a mechanism by which it could provide new additional allowances to the market to prevent prices from exceeding the highest price in the APCR. CARB should further study other means of increasing the supply of compliance instruments, such as offset carryover across compliance periods, the redistribution of unused offsets, and widening the offset market geographically and temporally. (WSPA 1)

Response: Thank you for the comment. The reference to section 95870(j) was made in error and has been corrected as part of the 15-day regulatory package. Section 95913(f)(5) now correctly refers to section 95870(i). This section was included in the 45-day regulatory package but was not correctly referenced.

The proposed cost containment provision does not create additional allowances and therefore maintains the environmental objective of the program. ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 over a reasonable range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB staff will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

I-2.6. Comment: The proposed cost containment mechanism is useful but may be insufficient: The cost containment mechanism set out in proposed new sections 95870(i) and 95913(f)(5) of the Regulation involves taking allowances that would otherwise be auctioned in future years of the cap-and-trade program and putting them into the Reserve. This mechanism is welcome as it would help to contain prices if there is a short-term price spike.

However, this mechanism would not be sufficient to contain allowance prices if there were a long-term supply/demand imbalance. Only a limited number of additional allowances are made available in the Reserve, and in some circumstances such as an extended period of low hydropower and nuclear power availability, low offset availability, and high economic growth the additional supply could be exhausted. Furthermore, the sale of these additional allowances from the Reserve would increase the scarcity of allowances in later years of the program, potentially contributing to higher prices towards the end of the program.

Therefore, the proposed cost containment mechanism does not appear to satisfy the Board's resolution, which requires a mechanism that ensures that allowance prices will be no higher than the highest price of the Reserve. Insofar as studies show the risk of prices exceeding this level is between 3 percent and 22 percent, depending on the scenario modeled, SCPPA considers that it is very important to comply with the Board's resolution. (SCPPA 1)

Response: ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 over a reasonable range of plausible conditions. However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB staff will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

Regarding studies that have analyzed the risk of the allowance price exceeding the Reserve tiers, in the coming months, the Market Simulation Group (MSG) will be releasing a final report outlining their analysis of the supply and demand for Cap-and-Trade allowances through 2020. The findings and recommendations made in the MSG analysis, including methods to mitigate the risk of unacceptably high allowance prices, will be included in any future consideration of additional long-run cost containment mechanisms.

I-2.7. Comment: We believe the current proposed regulatory amendments on cost containment do not go far enough in that they do not bring additional compliance instruments into the market. The proposed method for cost containment may be able to address limited, temporary price spikes, but will not address the more concerning and damaging structural or persistent high allowance costs in the cap and trade program. Moreover, to the extent the proposal for cost containment can address short term price spikes, it does so in a way that creates greater scarcity of allowances in future compliance years – increasing the potential for future price spikes – without addressing fundamental flaws in the cap and trade program design.

We believe that staff's consideration of adequate cost containment design measures presents an opportunity to improve the program for the long haul, make it more sustainable, and provide leadership in tackling climate change around the globe. We believe strongly that the right cost containment measures can and should avoid having problems occur in the first place – rather than simply attempting to address a problem once it has occurred. The Allowance Price Containment Reserve (APCR) was designed as a price cap. Cost containment design measures are very different than a price cap – and these two very different design elements should not be conflated. There is no reason or need to allow allowances prices to spike to the highest APCR tier when there are actions that staff can take now to avoid or greatly minimize the potential for this outcome and that also improve the sustainability of the program.

Cost containment measures that suggest re-filling the APCR, without addressing fundamental design flaws in the program are short sighted and fundamentally flawed because they allow prices to run up before any additional cost containment measures are able to take effect. This will allow needless and avoidable impact to be felt by consumers, industry and the state's economy. It is very likely that if the program gets to the point where the APCR is exhausted – or nearly exhausted – turmoil in the allowance and energy markets, and a consumer backlash, will result in swift action by the Governor or the Legislature with CARB losing control of the solution. Moreover, affected businesses dislocated by both the direct and indirect costs of high allowance and energy costs may be forced to make decisions to reduce, curtail or relocate production before prices reach the level of the highest APCR tier.

So while potential action taken by the Governor or the Legislature in reaction to allowance price spikes may be viewed as a necessary short-term response given the potential impacts on the economy from a swift and/or sustained run up in allowances prices, this sort of abrupt action can also have lasting negative and unintended consequences, can't undo decisions that have already been made by businesses – and can be avoided with proper planning and design. (BP 1)

Response: ARB staff agrees that there are multiple ways to prevent allowance prices from becoming unacceptable high, many of which are built into the design of the Cap-and-Trade Program. In regards to the specific cost containment provision in the proposed regulatory modifications, ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 in preventing the allowance price from exceeding the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions.

However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB staff will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

I-2.8. Comment: As stated in IETA's previous 2 August 2013 stakeholder submission, IETA supports ARB's proposal (as an initial first step) to make available 10% of future allowance budgets, as needed, at reserve sales once per year starting in 2015 at the highest price tier of the Allowance Price Containment Reserve (APCR).

This provision may provide some short-term relief in the case that prices rise unexpectedly. However, IETA does not believe that this provision adequately satisfies the Board Directive to prevent allowance prices from rising beyond the APCR, particularly in the case of an extended period of high demand due to unforeseen market dynamics or economic imbalances. Ultimately, it is in ARB and IETA's interest alike to ensure that prices do not rise so high that the Governor feels pressure to step in and exercise his/her right to suspend the cap-and-trade program. (IETA 1)

Response: ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 in preventing the allowance price from exceeding the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions.

However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB staff will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

I-2.9. Comment: The Regulation should include more robust cost containment protections that represent a suite of measures: Ensuring that the price of allowances never reaches the highest level of the Allowance Price Containment Reserve Account (APCR) is crucial to the success of the Program. NCPA appreciates staff's response Board Resolution 12-51, but the proposal set forth in the Proposed Amendments falls short of fully addressing the concerns that precipitated the Board's direction. In Section 95913(f)(5)(E), the Proposed Amendments would increase the availability of allowances at the highest priced tier APCR, which provides covered entities some relief in the event of short-term price spikes. However, this cost containment proposal – without more – does not address the specific direction set forth in Resolution 12-51 to ensure that "allowance prices will not exceed the highest price tier" of the APCR. The overall price of allowances may exceed this threshold, and the option does not protect against long-term price volatility, as it draws from allowances that would be available in future years. Nor does the proposal guarantee the availability of allowances for all covered entities. While purchases from the APCR are restricted to covered entities, the APCR does not have a mechanism to ensure a sufficient supply of allowances to meet demand, and if there are insufficient allowances, covered entities will be given only a pro-rated share of their requested purchase amount under the unrevised provisions of section 95913(h). Furthermore, the Proposed Amendment does not specifically address more moderately priced responses to potential price volatility that may not necessarily result in exhausting the APCR, but which could adversely impact the price and availability of allowances generally.

NCPA urges the Board to direct staff to continue working with stakeholders and its own Emissions Market Assessment Committee to develop a long-term strategy that would address instances of prolonged price volatility, as well as allowance availability. As noted in the Joint Utility Group proposal presented during the June 25 Cap-and-Trade Workshop, "a robust cost containment approach would utilize a combination of approaches to ensure success."4 The Regulation should include a suite of cost containment measures – including those that can be implemented in the near and long term. These measures should incorporate options that increase the availability of allowances and implement certain triggers that ensure covered entities will have access to allowances, even in advance of a depletion of the third tier of the APCR. Doing so will help to ensure the success of the Program and meet the specific direction provided by the Board in Resolution 12-51. (NCPA 1)

Response: ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 in preventing the allowance price from exceeding the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions.

However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB staff will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

I-2.10. Comment: The ARB should include additional modifications to address cost containment pursuant to board resolution 12-51. SMUD welcomed Board Resolution 12-51 asking ARB staff to develop proposals to prevent allowance prices in the Cap-and-Trade program from rising above the price in the 3rd tier of the APCR, while preserving the environmental integrity of the Cap-and- Trade structure, and being reasonably available in 2013-2020. To SMUD, this second part of the resolution is as important if not more important than the first part – we desire costs to be as low as possible, but more importantly, we want to achieve our GHG reduction goals. SMUD believes that the third part of the Resolution implies that ARB should act during the 2013 Cap-and-Trade update rulemaking, or very soon thereafter, to enact further cost containment measures.

The proposed modifications in the Proposed Regulation Order are not sufficient, in SMUD's opinion, to address the goals of the Board's resolution. The Proposed Regulation Order primarily includes a provision to "borrow" a finite number of allowances from future vintages and make these available at the highest price tier of the APCR, and only at limited times (there is also a provision to ensure that offsets procured and retired are not inadvertently "lost" and an additional offset protocol being proposed). Should this provision for a limited amount of additional allowances in the APCR be insufficient at any time, or should high prices ensue during an auction other than the "end of a compliance period" auctions identified in the Proposed Regulation Order, then the Cap- and-Trade Program regulations would "ration" procurement from the APCR, leading to market prices rising above the level suggested in Board Resolution 12-51. In addition, should the envisioned borrowing of allowances from future vintages be pervasive or occur multiple times, it is clear that fewer and fewer allowances will be made available to moderate prices, meaning that this provision clearly does not achieve the Board Resolution goals in cases where there is a long-term change in demand/supply characteristics of the Cap-and-Trade market.

ARB staff may feel that the proposed limited borrowing is sufficient to address the Board's Resolution because the scenarios in which demand/supply conditions lead to 3rd Tier APCR prices are unlikely. However, staff acknowledges in the Initial Statement of Reasons that accompanied the 45-day language that unanticipated conditions might "… create a long-term and persistent increase in the demand for allowances … [in which case] … the proposal would not ensure that allowance prices do not exceed the Reserve top tier price." (Page 43 of ARB 2013 Initial Statement of Reasons, emphasis added.) This statement is consistent with the EMAC analysis found in the paper: "Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap-and-Trade Market, March 12, 2013." This analysis states that there is a "non-trivial possibility" that auction prices could reach unacceptably high levels due to a systemic imbalance in market fundamentals.

In addition, SMUD points out that there was a bill being seriously considered in the 2012-2013 California legislative session that would significantly limit the supply of carbon offsets in the Cap-and-Trade program if it had been enacted. SMUD understands that this bill will likely be considered by the legislature again in the next legislative session, and that there are constituencies in California that will continue to attempt to limit the use of offsets in the Cap-and-Trade program. Market analysis of such limits points to significantly higher prices in the Cap-and-Trade market – in some cases well above the APCR 3rd Tier price. Since offset supply is limited to 8% of the total compliance instrument supply, the market analysis here suggests that a reduction in total supply of less than 8% from that expected can have significant market and pricing impacts.

SMUD can easily imagine scenarios where either supply (as indicated above) or demand, or a combination of the two, yields a demand/supply situation that is 5-10% "tighter" than expected, potentially leading to prices that would be inconsistent with the intent of Resolution 12-51. (SMUD 2)

Response: ARB staff is confident that the proposed mechanism satisfies the directive in Board Resolution 12-51 in preventing the allowance price from exceeding the highest price tier of the Allowance Price Containment Reserve while maintaining the environmental objectives of the program over a reasonable range of plausible conditions.

However, ARB staff also acknowledges that unanticipated conditions could result in a long-term imbalance of in the supply and demand for allowances. To address the possibility of long-term cost containment issues, the Board has issued Resolution 13-44, directing ARB staff to return by 2018 with the design of the post-2020 Cap-and-Trade Program, including cost containment provisions. In the post-2020 design, ARB will work with stakeholders and researchers to address concerns related to the potential for long-term supply and demand imbalance through cost containment provisions to ensure the long-term stability of the program.

With respect to the portion of the comment regarding offsets, ARB staff is committed to developing offset protocols that fit the requirements of AB 32 in sufficient supply for offsets to be available to satisfy up to eight percent of the compliance obligation of covered entities. In additional to the proposed mine methane capture protocol, a methane rice cultivation protocol is also being developed. ARB staff looks forward to working with stakeholders and researchers to identify and bring to fruition additional offset protocols and to continuing to evaluate the potential for sector-based offset crediting programs.

J. MINE METHANE CAPTURE COMPLAINCE OFFSET PROTOCOL

General Support for Protocol

J-1.1. Multiple Comments: CE2 Carbon Capital, a company which finances and develops carbon emissions reduction projects, supports the addition of new compliance offset protocols that provide real, additional, verifiable greenhouse gas reductions for California's businesses and consumers to manage their costs to comply with the Cap-and-Trade Program.

Coal plays a major role in California, the United States, and globally. Approving the MMC protocol begins to address the 70 million tons of CO2e emissions released into the atmosphere in the United States each year by the coal mining industry. According to the EPA, coal burning electricity generators represented the largest part of our national electricity supply—accounting for 95% of all coal consumed for energy in 2011. Worldwide, coal represents nearly 40% of global energy use and is responsible for over 40% of global CO2 emissions. ARB's MMC protocol incentivizes the reduction of GHG emissions resulting from coal mining activities in the United States, which are unregulated by the EPA. (CE2CAPITAL 1)

Comment: Today, methane emissions at coal mines are unregulated by the federal government, a situation that is likely to remain into the foreseeable future. As a result, most mine methane emissions are released into the environment. Without revenues from carbon offsets, there is no economic incentive to mitigate them. You can see how this has played out in the landfill gas methane capture sector as the mitigation is being curtailed now that compliance-grade offsets are no longer an economic incentive. What the Board is really considering today is whether or not to create an incentive to fund additional emissions control projects that will otherwise not take place and whether California will exert its traditional leadership role at the vanguard of U.S. environmental policy. We believe you should and we hope that you will. (CE2CAPITAL 2)

Comment: In short, we believe the Protocol represents another major step forward in California's and the Board's successful efforts to develop the first GHG cap-and-trade compliance offset market in the U.S. We urge the Board to adopt the Protocol in its current form.

As drafted, the Protocol provides effective market-based compliance mechanisms and monetary incentives to promote the capture and destruction of anthropogenic methane emissions from active or intermittent surface and underground coal and trona mines and abandoned coal mines in the United States ("MMC Projects"). Specifically, in furtherance of the stated objective of AB 32, the California Global Warming Solutions Act of 2006, the Protocol seeks to achieve the maximum technologically feasible and cost-effective mine methane emission reductions for these industries in order to mitigate the adverse environmental impacts of climate change in California. Without the Protocol the status quo will continue; coal and trona mine GHG emissions will be released and contribute to climate change. The Protocol offers a direct incentive to capture and destroy these emissions now.

In crafting the Protocol's performance standard, the Board staff considered complicated project-based additionality arguments and other performance metrics in earlier voluntary market mine methane protocols. In doing so, the Board staff has charted a course in which the Protocol establishes a comprehensive and well-conceived program that:

- Includes in its "eligibility criteria" a wide range of MMC Projects and rewards certain early action methodologies for mine methane capture, but excludes the "business-as-usual" coalbed methane development for interstate pipeline sales that occurs at several underground coal mines in the eastern U.S.
- Contains clear and straightforward additionality tests, quantification methodologies, and technologically feasible cost-effective end use options that should promote maximizing the volume of permanent and verifiable emissions reductions in furtherance of AB 32's mandated objective to reduce GHG emissions.
- Focuses on maximizing the base of available offset credits, to lower compliance costs, and improve overall GHG market efficiency. (RCE 1)

Comment: My name is Michael Cote, the President of Ruby Canyon Engineering. We are a Colorado-based small business greenhouse gas consultants, coal mine methane experts, and also ARB verification body. I just wanted to offer support for the protocol. And in fact, we believe that it will achieve its goal of reducing greenhouse gas emissions in addition to effecting what we consider to be an institutionally and culturally difficult sector, the coal mine methane sector. We've been working for the EPA's Climate Change Division coal mine methane outreach program since 1998 to try to affect the projects worldwide. What we've seen in countries that offer incentives like China and Germany and Australia, we've seen the most projects developed in those countries. And whereas, countries like Ukraine and Russia and the United States where no incentives are offered, we're seeing very little development in that sector. So with the point being we really feel like the incentives are effective in this space. (RCE 2)

Comment: The Climate Action Reserve (the "Reserve") applauds the Air Resources Board and its staff's efforts to amend the cap-and-trade regulation and, in particular, to expand the potential supply of carbon offsets through the adoption of a protocol for Mine Methane Capture (MMC) projects. We strongly support the adoption of this protocol and are pleased to note that the proposed MMC protocol mirrors and incorporates many significant elements of the Reserve's Coal Mine Methane (CMM) Project Protocol Version 1.1. like the Reserve's CMM protocol, we believe the MMC protocol will ensure that offsets generated from mine methane projects are rigorously and conservatively quantified, and meet criteria for being real, additional, permanent, verifiable, and enforceable.

Development of the Reserve's CMM Protocol

The Reserve's Board of Directors adopted Version 1.0 of the CMM protocol in October 2009. The protocol provides a standardized approach for quantifying, monitoring and verifying the greenhouse gas (GHG) reductions from methane destruction projects at active underground coal and Category Ill gassy trona mines in the United States and its territories. It was developed in a public process involving intensive consultation with a stakeholder workgroup consisting of industry representatives, project developers, project verifiers, consultants, academics, and U.S. EPA staff. The process culminated with a 30-day public comment period and a public workshop, following which the Reserve received and responded to numerous stakeholder comments. In 2012, the Reserve made technical revisions to the protocol, resulting in Version 1.1. The revisions were reviewed by stakeholders in another 30-day comment period, and Version 1.1of the protocol was adopted by the Reserve's Board of Directors in October of that year. This development process resulted in a comprehensively rigorous protocol for determining the eligibility and additionality of projects at active underground mines, and for quantifying and verifying the GHG reductions they generate through methane destruction. We believe the core of ARB's proposed MMC protocol is equally sound and rigorous.

Real, Additional Reduction Opportunities

As ARB staffs analysis suggests, there are substantial opportunities for reducing methane emissions from U.S. coal mining operations. In 2011, nearly 70 million tons of CO2-equivalent were released from mining operations nationwide- almost 12 percent of total U.S. methane emissions. These emissions are an attractive target for carbon offsets because they can be reduced in ways that fully satisfy offset quality criteria:

1. Reductions in mine methane emissions can be accurately measured, quantified, and verified in a standardized fashion. It is easy to determine destroyed methane volumes through metering technologies.
2. Reducing methane emissions results in permanent reductions that cannot be reversed.
3. Notwithstanding complications around mineral rights, it is relatively easy to establish Clear ownership for mine methane reductions and avoid double-counting or double-claiming.
4. There is a large potential for additional emission reductions and additionality for specific project types can be clearly established using standardized methods.

Currently, only about 22 percent of methane liberated from mines in the United States is captured and utilized. In developing the CMM protocol, the Reserve's analysis (affirmed by separate analysis by ARB staff) indicated that such capture and utilization happens overwhelmingly at mines that send the methane to natural gas pipelines.[182] Although not all mines do this that could, we determined that sending mine methane to a pipeline was effectively business-as-usual and should not qualify as an additional project activity. The same analysis, however, indicated that capturing and destroying methane

182 See Appendix A of the Climate Action Reserve's Coal Mine Methane Project Protocol, available at http://www.clirnateactionreserve.org/how/protocols/coal-mine-methane/.

at active underground mines that would otherwise be vented from drainage systems is extremely rare. Likewise, capturing and destroying ventilation air methane (VAM) has been non-existent when not undertaken for carbon offsetting purposes. Finally, the analysis showed that these kinds of projects are rare or non-existent because they are likely to be uneconomical (and not, for example, simply more costly options than pipeline injection). For these reasons, we concluded that these kinds of activities should be considered additional, provided they meet certain eligibility conditions. (CAR 1)

Comment: My name is Gary Gero, the President of the Climate Action Reserve. We're very pleased to be here today to support the adoption of the mine methane protocol. And also very pleased that it's based on work that we did at the Climate Action Reserve. I was just looking back at the dates to see an anniversaries in light of Kassandra. It was almost to the day, just one day off, four years ago that we adopted our version of this protocol.

Our protocol was really based on a deep analysis of the circumstances regarding mining. We brought together technical experts from around the country, looked at mining operations, and really did a deep dive into determining what is truly additional in these circumstances and our protocol that is now forming the basis of the ARB protocol really sought to limit and provide exclusions to keep out non-additional projects. We are very happy to be part of the ARB's technical work group in this regard as well and help inform that process. And I think that this is, in fact, a very good protocol because the reductions can be very accurately measured. They are, in fact, permanent emission reductions. The ownership of those reductions is always very clear. And as you've heard, there is a large potential. All of those things are the things that you want in an offset protocol. (CAR 2)

Comment: In conclusion, we re-iterate our support for the MMC protocol and congratulate the ARB staff for developing a robust protocol in a consultative and transparent manner. This protocol will further diversify the sources of offsets that are eligible under California's cap and trade program, enable capped entities to meet their obligations in a more cost-effective manner, and it will also catalyze investments in transformative clean technology in the mining sector. We urge the Air Resources Board to adopt the protocol and related early action provisions at the earliest possible date. (VCS)

Comment: I'm here to speak on behalf of the mine methane and capture protocol. I'm in support of the protocol and I commend the Board and the staff that have worked on the protocol. They were very engaging. They worked very hard to understand the issues. California's been a leader for many, many things. And I think this is an opportunity for California to continue its leadership particularly for mine methane protocol. California has many riches, but one of the things California doesn't have is coal. They don't. So it's difficult to understand the mining industry, to understand that since it is not within our state boundaries. In the coal industry, mining industry, as previous speakers have mentioned, people worry about producing the coal and the coal has provided historically a quality of life that we enjoy today. Coal also has the moniker of being dirty. It has all sorts of other things. And we're moving ahead. One of the things that happens when you mine coal all the time is that you get methane emissions. This is an opportunity to address an environmental issue that is unlikely to be regulated at the federal level, to incentivize the companies that spoke here, like CE2 Capital, to develop projects that will reduce a true environmental issue and reduce the methane and perhaps be able to flare it or use it for on-site and beneficial use or co-benefit. I think it's a great opportunity. And again, I commend the staff. They did an excellent job of listening. (TOOLE ONEIL 1)

Comment: The MMC protocol could create a significant supply of "verifiable" and "additional" emission reductions

MMC offsets are "additional" because this proposed protocol addresses otherwise neglected methane emissions and incentivizes their capture and destruction. This protocol seeks to make an ongoing process less carbon-intensive above and beyond the current legal or regulatory requirements.

MMC offsets are "verifiable" because the ARB has crafted this protocol through an involved stakeholder process that represents the best available data and operational practices. The result is a series of assessments where emission reductions are repeatedly verified, and projects are reviewed for any inconsistencies. This means that when MMC offsets come to market they've gone through a complete and rigorous evaluation process.

In 2011, the US EPA estimated U.S. coal mines emitted about 62 million mtC02e. ARB has proposed a MMC protocol that could provide two clear benefits; (I) a significant supply of offsets to the California Cap-and-trade program while, (2) incentivizing the reduction of emissions that are currently being neglected. (SCE 2)

Comment: As the staff indicated in their presentation, the protocol does not in any way rule out future regulatory action on the part of the EPA or any states or regions where the protocol might be applied. So I encourage the Board to approve the protocol. Finally, once again, this would also show that California can demonstrate how to provide incentives to reduce a potent greenhouse gas in a way that works for both the environment and the business community. (SCE 3)

Comment: Lastly, we support the mine methane capture protocol. And we are puzzled why there are parties who think that this protocol is problematic. We have worked in great depth with the Air Resources Board staff to ensure that this protocol is robust. We believe that it is very technically sound. And we believe that it introduces an incentive to destroy methane very simply that would not otherwise be captured. It's very hard to understand why that could be a bad thing to do. (CHEVRON 3)

Comment: I’m here to talk about the cap and trade program. I followed it silently over the past few years and seen it develop. I was here last month at the cap and trade hearing meeting when we called it the new offset compliance protocol meeting. And I think that they're on a great path of allowing more offset protocols to be introduced into cap and trade. (LEE)

Comment: Our group congratulates ARB on the hard work accomplished and the release of the Mine Methane Capture Protocol. In our opinion, this is a solid document which will allow for the generation of high quality offsets. We also wish to thank ARB for taking into account our comments and recommendations over the past weeks. (MERCURY)

Response: Thank you for the support.

J-1.2. Multiple Comments: I will also say that the destruction of the low concentration methane from ventilation air systems, which is a component of this protocol, is a new and innovative application of technology. That's exactly what AB 32 is looking to do is to drive new and innovative applications of technology and certainly one of the key benefits of offsets themselves. So I think there is a lot of good reason to support this protocol. (CAR 2)

Comment: Thank you for the opportunity to comment in support of ARB's adoption of the Proposed Compliance Offset Protocol for Mine Methane Capture (MMC) Projects. Blue Source fully supports the development of new compliance offset protocols that provide real, permanent and verifiable greenhouse gas emission reductions.

Blue Source urges ARB to adopt the Proposed Protocol for MMC Projects. Through its approval, ARB will enable voluntary participation in GHG emission reduction activities that, void of traditional economic viability and absent participation in California's Cap and Trade Program, would not otherwise occur. The protocol will establish a framework to allow companies to address the millions of tons of GHG emissions released from coal mining each year, without incentivizing additional mining activity. Adoption of this protocol will serve to encourage and promote the development and implementation of cleaner and more environmentally responsible practices in the industry, and will result in the ultimate goal: Reduced GHG emissions. (BLUESOURCE 1)

Comment: SCI operates an active, underground trona mine in Southwest Wyoming. Trona is processed into soda ash, a key ingredient in everyday products such as glass and baking soda. To ensure worker safety, SCI vents mine methane from the strata above and below the trona seam. SCI, which has no legal obligation to capture and treat the mine methane, developed and installed an innovative, cutting edge capture and treatment system. The system has been listed with the Climate Action Reserve and would be covered by the Proposed Protocol for MMC Projects. SCI is currently contemplating expansion of the system to double the mine methane capture and destruction capacity. Anticipation of the acceptance of the project into the ARB carbon offset program will play a key role in that investment decision.

Fundamentally, SCI believes that market driven cap and trade systems when properly deployed on a global scale will significantly reduce greenhouse gas emissions while at the same time preserving economic stability. ARB and the California legislature are to be commended for once again demonstrating national leadership toward environmental, economic, and social stewardship.

In the case of mine methane emissions, SCI believes that a well run cap and trade system in California will provide mine operators in the USA an economic incentive to invest capital in projects to reduce methane emissions which would not otherwise be legally required. And, these methane reductions can come from not only underground coal mines but also nonmetal mines, including trona mines like the one operated by SCI, that liberate methane as a result of the mining process. To this end, SCI supports the inclusion of non-coal mining operations in the Proposed Protocol for MMC Projects. Further, it is SCI's experience that as mine operators seek to design and implement methane capture and destruction systems it is quite likely that the technology to do so will evolve toward better, more productive and cost efficient systems. (SOLVAY 1)

Comment: Biothermica Technologies Inc. ("Biothermica") would like to thank the California Air Resources Board (ARB) for this opportunity to support the approval of the proposed Mine Methane Capture (MMC) Protocol.

Our support is provided from the perspective of a ventilation air methane (VAM) project developer and technology owner, having developed and implemented the first VAM destruction project at an active mine in the U.S.

Mine ventilation air methane (VAM) emissions are one of the largest sources of non-regulated greenhouse gas emissions in the U.S. Based on the nature of these emissions-high volume but very low methane concentration-carbon offsets are the most effective way to support the development of VAM abatement technologies.

Thanks to the carbon price signal finally provided by the Protocol's adoption, project developers will be able to deploy their innovative methane abatement projects at several U.S. mine sites. This price signal is a crucial factor, considering these projects rely on carbon offsets as a source of revenues. (BIOTHERMICA 1)

Comment: As a purchaser of power supplied by a coal mine methane capture project located in Colorado (3MW LLC), Holy Cross Energy, a Colorado electric cooperative, supports the development of this protocol. This protocol would enable the power industry to utilize a fuel supply that is otherwise being wasted and reduce greenhouse gas emissions.

Holy Cross Energy has been a leader in purchasing renewable power. Support from our consumers helped our Board of Directors to create an internal goal of obtaining 20% of our power from renewable sources by 2015. We currently have contracts to purchase power generated from solar, wind, hydro and woody biomass. Even though mine methane was not recognized as a renewable source by the State of Colorado when this project was undertaken, Holy Cross chose to participate in this project as the purchaser of its electrical output. The State of Colorado has since listed mine methane as a renewable resource.

Items that were important in our decision to participate in this project were:

- Reduction of Greenhouse Gas Emissions
- Use of a resource that is being underutilized (venting methane to atmosphere)
- Reduction of use of other fossil fuels for power generation
- The use of unitized reciprocating engines to generate electricity, enabling the relocation of the units as required to “follow” the methane source. Three separate 1 MW generators that can be run as required and could be relocated in the future.
- The possibility for heat recovery to be used in other processes
- Helping move this technology from development into production mode within the United States.
- The availability of carbon offsets.
- The possibility of this project to be replicated in other areas, allowing for additional distributed generation.

When Holy Cross Energy participated in this project, there were no protocols in Colorado similar to the one being developed for California. The mine at which the 3MW LLC project was located was not within our service territory, but we were able to purchase power and wheel it across several distribution and transmission systems. This resulted in additional costs that might have been avoided had the local distribution company been able to purchase this power directly.

Allowing methane capture to be counted toward reduction of Greenhouse Gas emissions will encourage other utilities to support these projects. Acceptance of this protocol will provide a method for measuring and encouraging this capture. (HCE 1)

Comment: Thank you for giving me the opportunity to speak in support of your amendment regarding the mine methane capture, Cap and Trade Program.
We support the amendment because it gives value to a waste product that is currently venting to atmosphere. This will encourage the development of technology and innovations to both detect the methane, capture it, and in some cases convert it to beneficial and economic use. (VESSELS 2)

Comment: Fundamentally ARB’s Mine Methane Capture amendment will attribute some value to a waste by product, methane emissions from mining activity, where before there was little or no value. This will encourage and accelerate the capture of mine methane and may add momentum to reduce methane emissions generally. This event resembles the beginning of the natural gas industry. Natural gas, the primary constituent of which is methane, was originally itself a waste by product oil.
Prior to adopting Mine Methane into ARB’s Cap and Trade Program this waste product only has an economic value if local conditions provide a cost benefit to use the gas. Mine Methane is not natural gas but rather a constituent of mine gas which includes highly variable concentrations of Nitrogen, methane, carbon dioxide and other gases.

There have been some advances in methane capture that have occurred anticipating an eventual incentive to capture mine methane. That these developments occurred in the absence of any significant incentive leads us to believe that the pace of mine methane capture will accelerate with the adoption of the Mine Methane Capture Protocol by ARB. Although the scientific consensus is that that methane emissions and soot are the two most important substances to control to slow global warming little has been done in the area of policy or regulations to incentivize and accelerate methane capture. Economic incentives that have been put in place have been very effective in effecting change in emissions, such as in Germany for example.

The ARB Protocol may raise awareness generally of the benefits of reducing emissions and encourage where feasible the waste product to be used as an energy source. This hopefully will lead to adoption of regulations by federal, state and local governments that can stream line the permitting processes to shorten the time it takes to bring the projects into operation. We have proven by the few projects we have done how difficult it is to get permits under regulations that did not anticipate capturing mine methane and oxidizing the methane to reduce emissions. The process of obtaining variances and exceptions from conventional permitting requirements take up time and financial resources to be satisfied.

For example the mine methane capture project from an active mine in Colorado was put into service with no carbon reducing incentives in place and took us over six years to complete. Finally when the local electric utility would not pay an economic price for the electricity we were assisted by a friendly electric cooperative four grids away. That electric coop had an agenda to show case greenhouse gas emission reduction projects by providing us an electricity price that made our first project economic. A local environmental and conservation group, The Conservation Center, strongly supported us and gave us and the coal mining company we worked with an award for our accomplishment. The press became aware of the novel nature of this project and spread the word. There is much more potential to expand the mine methane capture in this state and others. The ARB Protocol can shorten the six year time frame we have just endured. News of the Mine Methane Capture Protocol can encourage citizens to request more of these kinds of projects to be pursued and support adoption of constructive policies and regulations. As communities begin to understand what a carbon offset is and the beneficial effect of both capturing methane and putting the methane emission to beneficial use those communities could begin to advance similar goals to those of ARB. This could add momentum to other states joining the Western Climate Initiative or do something else constructive to capture methane or otherwise reduce greenhouse gas emissions.

Developments that have occurred in methane capture prior to adoption by ARB are briefly listed below.

Mine Methane injection into natural gas pipelines

Beginning roughly in the 1970s mine methane from active mines began to be recovered and treated for injection into natural gas pipelines. Natural gas prices rose to historic levels peaking in 2008 over $13 per thousand btus of natural gas and stimulated innovations in small scale nitrogen removal to concentrate methane to meet pipeline quality specifications. Last year the price of natural gas fell to $1.60 per million btus and have risen recently to over $3.00. At these current gas prices the economic incentives can be expected to have less of an impact and we know of no new recent projects.

Distributed Electric Generation

As of this date we know of two distributed electric generation facilities in the USA using mine methane as fuel with a total capacity of around 4.5 Mega Watts. These generators are European built low methane concentration reciprocating engines with computerized controls to optimize clean burning to reduce Nitrous Oxide emissions and most efficiently run to produce the most electricity. We understand there are at least two suppliers of 5 Mega Watt gas fired turbine electrical generation models. We know of none in use on mine gas currently. Electricity markets typically run from less than 3c per kilowatt hour to over 4c depending on local conditions. These prices are not sufficient to stimulate significant growth or the growth would be manifest.

Ventilation Air Methane Oxidation

Three different manufacturers have placed at least one each of their particular products in operation as pilot projects to oxidize and thus avoid methane emissions from Ventilation Air Methane (VAM) systems in the USA. VAM has less than 1% methane. The technology exists to take the heat from these generators and heat boilers for steam generated electricity. To our knowledge this has not been accomplished in the USA and present electricity prices would not support such projects.

Thermal Oxidation of vent methane.

Currently we know of only two of the fifty active mines in the USA that have methane thermal oxidizers or incinerators to oxidize methane before it is released to the atmosphere. The largest has a capacity to oxidize 3,700 mcfpd of methane. The manufacturer is European. This equipment does not provide any beneficial use but have wide operational flexibility and can operate over a wide range of methane volumes and concentration. They have a 15 year life and are specially designed and equipped to measure methane oxidation efficiency.

Detection, measuring and monitoring of methane.

There is some existing technology used infrequently to measure small volumes of methane emitting from the ground or from old vents, fractures etc. that are difficult to detect by the naked eye alone. Methane is odorless and colorless. Some of the methods are expensive such as flying instruments over historic coal fields. There are available measuring devices that can measure emissions coming from the ground. An array of such can begin to outline methane emission concentrations from a mine. Software and computerized controls

The facilities referred to above can be monitored on smart phones and be controlled by lap top computers.

Potential Developments that could occur post Protocol Amendment Adoption

Mine Methane Injection into natural gas pipelines

In this Protocol pipeline injection is eligible from abandoned mines innovation could restart as new facilities are installed and variable gas compositions are handled to treat gas to natural gas pipeline specifications.

Distributed electric generation

Gas Turbines could be installed on some projects with less maintenance and more efficient electric generation. This can come after enough experience with a methane source so the methane concentration is known. Turbines work best when the gas quality stays fairly constant. The addition of carbon offsets to Electric generation revenue could add sufficient value to encourage development of new equipment packages. Our company has an expectation of being able to develop 30-50 MWs of electricity generation ourselves if the economic benefits are sufficient.

Ventilation Air Methane

The technology exists to avoid a significant amount of Mine Methane emissions from Ventilation Air Systems. We know of a few project developers and mining companies that are studying how they would oxidize VAM. Some novel uses of VAM in plant and mine processes is being considered. This would not result in any beneficial use but once they are installed they produce a great deal of heat and that could lead to the use of the waste heat for some beneficial purpose.

Thermal Oxidation of vent methane

If the ARB Cap and Trade Amendment including Mine Methane Capture is adopted many more Thermal Oxidizers are likely to be installed and the waste heat they generate would be available for use. New products are being developed to oxidize the methane and capture the heat for electric generation if such an investment is economic.

Detection, measuring and monitoring of methane.

If venting mine methane has value then it is reasonable that we and others will expend greater effort in the hunt for such. That is likely to result to further innovation in the field of instruments designed to detect methane. Thank you again for the opportunity to offer our support for the adoption of the of the Mine Methane Capture Protocol in the 2013 Proposed Amendments to California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms. (VESSELS 1)

> **Response:** Thank you for the input on how the proposed mine methane capture (MMC) protocol is likely to impact the development of projects and related technologies. Staff agrees that adoption of the MMC protocol will lead to technological advancements in mine methane capture and destruction that would not occur without the financial incentive provided by the compliance offset protocol.

J-1.3. Multiple Comments: The MMC protocol can provide a significant supply of offsets to California's Cap-and-Trade market. A recent study conducted by Ruby Canyon Engineering estimates that MMC offset projects have the potential to provide over 28 million tons of carbon offset reductions. This represents a significant influx of offset supply to California's Cap-and-Trade Program at a time when more offsets are needed to meet future demand. Based on data form the ARB approved Early Action Offset Programs, there would be an additional 2 million tons of early action offsets that could transition to the ARB program in 2014, in time to add immediate supply in the First Compliance Period. (CE2CAPITAL 1)

Comment: The substantial offsets supply the MMC protocol can deliver is an important part of meeting the cost containment efforts of the program. With two years left, in compliance period one, we're not quite at the halfway point for the offset requirements projected for the program. These emissions reductions are a critical part of the cost containment, not only for covered entities, but for rate payers as well. (CE2CAPITAL 2)

Comment: Offset credits represent a crucial cost containment mechanism to help the California cap-and-trade program achieve GHG emission reductions in an economically efficient manner. IETA encourages officials to approve and make effective the protocol as soon as possible. (IETA 1)

Comment: In the proposed rulemaking, ARB would add a protocol that has the potential to substantially reduce this shortfall. The Mine Methane Capture Protocol targets reductions that are measureable based on sound technology, and result in a significant potential US supply of GHG reductions that would not otherwise occur under business as usual. The AB 32 IG supports the Mine Methane Capture Protocol as an important step towards increasing the supply of offsets. (AB32IG)

Comment: Therefore, the Joint Utilities urge ARB to approve the proposed Mine Methane Capture (MMC) and forthcoming Rice Cultivation offset protocols, which will pave the way for additional offset credit supply. Approval of the MMC offset protocol is important because it can facilitate the generation of a significant supply of offset credits. While estimates vary, MMC projects have the potential to reduce tens of millions of tons of CO2e from mines whose methane would otherwise be released to the atmosphere. (JUC)

Comment: Approval of the Mine Methane Capture (MMC) protocol is important because it can facilitate the generation of a significant supply of offset credits. While estimates vary, MMC projects have the potential to reduce tens of millions of tons of CO2e from mines whose methane would otherwise be released to the atmosphere. (PGE 1) (PGE 2)

Comment: If I want to pick up where Frank left off on the mine methane protocol. PG&E supported cap and trade and supported this program in large part because of where we saw offsets playing a valuable role in bringing prices -- keeping prices contained. So mine methane is an area of very potent greenhouse gas that we think the Board's protocol is doing exactly the right thing. We urge your support on that. (PGE 3)

Comment: First, we support the coal mine methane offset protocol. As you know, offsets are a critical cost containment process so additional protocols are important. (WSPA 3)

Comment: WSPA strongly supports the adoption of the new protocols for Coal Mine Methane. Allowing offsets from other geographic areas besides California provides an important cost containment mechanism for the program that is needed to keep allowance prices in control. As has been stated by many stakeholders, a cost effective program is critical to prevent emissions and economic leakage of jobs to other states that can adversely impact the economic viability of the state.

The CMM protocol will provide a significant supply of offsets to California's cap and trade market. A recent study conducted by Ruby Canyon Engineering shows CMM offset projects could provide over 28 million tons of carbon offset reductions. This would be a significant influx of offset supply to California's Cap-and-Trade system at a time when more offsets are needed to meet future demand.

By way of comparison, analysts expect the cap and trade program to need as many as 220 million tons of carbon offsets and so far the ARB has only approved a few project types that will not produce the needed supply for cost-effective compliance options under AB 32's requirements. Hence, the CMM protocol could provide over 10% of the anticipated offset supply. This is important in light of recent analysis by the American Climate Registry that finds there will be a shortage of offset supply by 29 percent in the first compliance period and up to 67 percent by the third compliance period. This underscores the need for the CMM protocol. ARB approval of the protocol will provide an important financial incentive to encourage coal mine owners and operators to capture and utilize mine methane. (WSPA 1)

Comment: In the proposed rulemaking, ARB would add a protocol that has the potential to substantially help meet these goals. The Mine Methane Capture Protocol targets reductions that are measurable based on sound technology, and result in a significant potential US supply of GHG reductions that would not otherwise occur under business as usual. Through strict technical guidelines, offset protocols provide the business community and the agency with the assurance that there is a sound technical basis to help create real and permanent emissions reductions. Chevron supports the Mine Methane Capture Protocol as an important step towards increasing the supply of offsets. (CHEVRON 2)

Comment: Finally, just want to also thank you. It's happening again and again here, for the mine methane offset protocol. Of course, increasing the option in cap and trade is going to keep the cost down for everybody. (CMTA 1)

Comment: Additional supply options should include: f) Approval of the Mine Methane Capture Protocol. (CCEEB 1)

Comment: Thus SCE firmly supports the ARB as it develops additional offset protocols to enable compliance at the lowest possible cost. Mine Methane Capture is a step toward that goal. (SCE 2)

Comment: Indeed, the study showed allowance cost would increase significantly without the use of offsets. So we have to look at the mine methane protocol as a significant part of the cost containment program. Further, there is a great example of a way to reduce emissions from an existing economic activity. It's hard for me to understand how moving backwards would help to reduce the release of methane. You have in front of you a protocol that can go a long way towards pulling a great amount of methane out of the atmosphere. Not approving this is not going to help that. (SCE 3)

Response: The MMC protocol is the fifth compliance offset protocol approved by the Board. The proposed protocol is consistent with the requirements of the Cap-and-Trade Regulation and AB 32 including the objective of achieving cost-effective emission reductions. Staff has estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has adopted—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. Staff is committed to evaluating additional offset types to ensure sufficient offset supply.

A rice cultivation protocol is not included in this rulemaking and any comments related to that protocol would be considered and addressed during the public process associated with the evaluation of that protocol and potential future rulemaking to add the protocol to the Cap-and-Trade Regulation.

It should be noted that CE2 Carbon Capital submitted two sets of identical written comments on October 15, 2013. As these written comments are duplicative, the response above serves to address both simultaneously.

It should also be noted that WSPA's written comments submitted on October 16, 2013 (WSPA 1), were incorporated by reference as part of Valero's comments submitted on October 17, 2013 (VALERO). As these written comments are duplicative, the response above serves to address both simultaneously.

General Opposition to Protocol

J-1.4. Multiple Comments: Offsets are counterproductive and do not lead to real, additional, or permanent emissions reductions.
Addressing climate change requires direct pollution reductions, as well as the use of sustainable and renewable energy sources. The use of offsets, and the possible allowance of offsets from coalmines, is completely counterproductive to any real progress in reversing the root causes of climate change.

Offsets from coalmine methane capture would also run into many of the same problems that other types of offsets face—issues with ensuring additionality, achieving real reductions, risks of fraud, and pollution would continue at its source in California. Looking specifically at the requirement of additionality, some serious concerns arise. It is clearly stated in the "Proposed Compliance Offset Protocol Mine Methane Capture Projects" that additionality must be met—any methane capture project under consideration must be in addition to the status quo or business as usual. However, it is also stated in the draft protocol that "compliance offset projects must have an offset project commencement date after December 31, 2006"— meaning that any project that commenced in the last six years is eligible for offsets and considered "additional", even though it's already in effect and technically not additional.[183] This built in "additionality" makes the integrity of the California Air Resources Board highly suspect.

On behalf of Food & Water Watch, I urge you to reject offsets from coalmine methane capture. Offsets do not lead to real, additional, or permanent emissions reductions, and offsets from coalmine methane capture would be completely counterproductive to any emissions reductions.

The point of addressing emissions is to reduce them for the sake of current and future generations, not to make the process easier for those causing the emissions. (FWW)

Comment: We believe that the current Protocol, in the absence of additional analysis or mitigatory measures, risks significant over-crediting of emissions reductions, and failure to meet the statutory requirements of AB 32. We recognize that, in all offsets protocols, some amount of non-additional or non-real crediting is likely and is anticipated and that no protocol will be perfect. Our concern is that without further and detailed analysis and precautionary measures to address specific outstanding issues, the current protocol risks generating enough credits that are not based on real emissions reductions that it could substantially undermine the credibility, integrity, and ultimately, the efficacy of the

[183] California Air Resources Board, California Environmental Protection Agency. "Proposed Compliance Offset Protocol Mine Methane Capture Projects." September 4, 2013 at 21.

entire Offsets Program. We present each of these concerns in the comments below with specific suggestions on how the Board may proceed with addressing each one. None of these suggestions would be difficult to implement.

Since the Board is in a position to create an offsets program that serves as a model for other programs, doing the proper analysis and taking conservative precautionary decisions about project eligibility not only has implications for the environmental integrity of California's cap-and-trade program, but has the potential to influence cap-and-trade programs in other jurisdictions well beyond California through precedent and example. (STANFORD 2)

Comment: Having participated in this process actively and having seen the impressive work of the staff in preparing this protocol, I'm here today to say simply we aren't there yet. In my academic opinion, this protocol is not quite ready for adoption. The details of our analyses and suggestion are included in our submitted written comments. Now, I'm not an offsets opponent. I love offsets. I think they're great. My concern is that three years from now I don't want to see a scientific paper come out that says half of the offsets being generated from this protocol are junk. Let's take more time to get it right. Take the time to make sure we're crossing every T, dotting every I. And we can do this. So I urge the Board not to adopt this draft yet and ask staff to draft the full analysis necessary to ensure the program's long-term integrity. (STANFORD 4)

> **Response:** The limited use of offsets serves as an important cost-containment feature in the Cap-and-Trade Program, which reduces emissions and works in conjunction with other AB 32 measures that shift California's energy consumption toward renewable sources. Staff disagrees with the statements about offsets not leading to real, additional, or permanent emission reductions and being at risk for fraud. The MMC offset protocol, which quantifies the capture and destruction of fugitive methane emissions, is the fifth compliance offset protocol to be considered by the Board to provide voluntary greenhouse gas reductions. The four previously adopted protocols are being successfully implemented. The MMC protocol meets the same rigorous AB 32 carbon offset requirements as the existing protocols, including third-party verification.
>
> As noted in a comment, the protocol text states that compliance offset projects must have an offset project commencement date after December 31, 2006. This is compliant with the Cap-and-Trade Regulation section 95973(a)(2)(B). December 31, 2006, reflects the implementation date of AB 32 and makes the bounds more clear for ARB to determine if an offset project was implemented to achieve AB 32 goals. This date also allows ARB to credit early actors as required under AB 32.
>
> Staff does not believe that an offset protocol that incentivizes the capture and destruction of methane that would otherwise be freely vented into the atmosphere can be reasonably characterized as counterproductive. Staff also disagrees with comments suggesting that the MMC protocol will lead to over-

crediting. The Cap-and-Trade Regulation embodies a principle of conservativeness for the quantification of emissions reductions. Staff observed this principle when evaluating business-as-usual practices, developing appropriate performance standards, and establishing corresponding eligibility requirements for each project activity. The MMC protocol also employs conservative baseline scenarios and uncertainty deductions. This approach ensures that the MMC protocol's quantification methodology underestimates rather than overestimates any achieved emission reductions.

Please note that a more detailed response to the specific issue of additionality policy, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.15.

Public Process and Protocol Development

J-1.5. Multiple Comments: EDF supports the rigorous process CARB has engaged in to develop rice cultivation and mine methane protocols. (EDF 1)

Comment: Finally, we want to acknowledge that during the course of numerous public hearings, technical working group meetings, and preparation of the draft Protocol, the Board has gone to great efforts to thoroughly investigate and develop a well-informed economic, scientific, and technical understanding of the physical nature of mine methane emissions, MMC Project economic and operational issues, and the scope of the existing regulatory environment. The comprehensive nature of the draft Protocol reflects the considerable time, energy, and analysis invested by the Board and its staff on behalf of the people of California. (RCE 1)

Comment: As a leader in sustainable business practices, SCI supports ARB efforts to reduce global greenhouse gas emissions through market driven cap and trade program. We particularly applaud the efforts of ARB Staff to develop the Proposed Compliance Offset Protocol for Mine Methane Capture (MMC) Projects. Their professionalism and dedication to the development of a high quality work product while giving serious consideration to the participating public during the technical working sessions was admirable. SCI urges ARB to adopt the Proposed Protocol for MMC Projects and accompanying amendments to the Cap and Trade Regulations. (SOLVAY 1)

Comment: We understand the actual implementation of the Protocol will take place only after its approval by the Office of Administrative Law (OAL) and the training of accredited verifiers. While we understand and respect ARB's administrative constraints, we do wish to underline the importance of not delaying the implementation schedule in order to ensure MMC projects will start delivering offsets as soon as possible. (BIOTHERMICA 1)

Comment: IETA strongly supports the proposed compliance offset protocol for mine methane capture projects, and appreciates the thorough stakeholder engagement process ARB held in the development of the protocol. (IETA 1)

Comment: We'd like to thank the ARB staff today for their hard and thorough work to understand the value and evaluate the technical merits of the mine methane capture protocol and for taking the care to delve into the facts and data on a very complex subject. We're here today to voice our support for staff's recommendation to include the MMC protocol as part of the Cap-and-Trade Program. (CE2CAPITAL 2)

Comment: One is about this is in support of the mine methane protocol. First, I've heard quite a few comments that it would be better to have an academic peer review process for the mine methane protocol moving forward and potentially delay. I would say I'm amazed at how long it has taken to get to today to pass the coal mine methane protocol. At this time back in 2009, we assumed there would be dozens of offset protocols that would be approved through ARB. The last time that protocols were approved was 2003. The amount of scrutiny that has gone into this existing protocol has been unprecedented in my mind. Much of the material that has gone into this was developed back as late as 2007-2008. Staff have been more open than I've ever seen and transparent and trying to bring in as many parties. And even proactively working with some of the groups that have talked today to give even more and as much information as possible and go out of their way to help them. I really commend the staff. I know that's what we want to say. It's been amazing over the last couple years on that. I think all of you should be commended. Obviously, there are baselines and additionality components and of course whatever is going through is going to be additional from what has been done anyway. (CE2CAPITAL 3)

Comment: My name is Aaron Strong from Stanford University. I'd like to start by thanking the staff for their incredible work. And in all honesty, I've been working with the staff very closely for the last six months participating in the technical working groups that have been used to help develop the mine methane offset compliance protocol. And I participated in this process with goal of helping to ensure the environmental integrity of both this protocol and of the Cap-and-Trade Program as a whole through careful analysis, research, and devoted attention to detail.

I'm not from an advocacy organization, nor do I have any financial interest in outcome of the protocol. I'm here in my academic capacity. I participated in the process out of the firm and profound belief that where many other carbon offsets schemes in other cap-and-trade programs have failed or been ineffective due to flaws in their initial design that California is in a unique position to finally get this right by ensuring that the market does not become flooded with junk credits that do not represent real reductions. In the technical working group, we discussed the details of hyperbolic declining curves used to estimate baseline emissions from abandoned coal mines and the global warming potentials of non-methane hydrocarbons leaking from mines.
As a doctoral student with an amazing opportunity to engage with Board staff on these scientific questions, I have to tell you being part of this process was humbling and inspiring. In writing the rules to address many of these issues, the staff conducted conservative analyses that erred on the side of caution in order to avoid crediting emissions reductions that aren't real. We applaud this effort and commend staff on their tremendous attention to detail. (STANFORD 4)

Response: ARB appreciates the recognition of its extensive public process in the development of the MMC protocol. As evidenced by this process, the development of a new compliance offset protocol takes considerable time as staff seeks to engage with a diverse set of stakeholders and put forward the best possible protocol that meets the rigorous standards of the Cap-and-Trade Regulation and AB 32.

A rice cultivation protocol is not included in this rulemaking and any comments related to that protocol would be considered and addressed during the public process associated with the evaluation of that protocol and any potential future rulemaking to add the protocol to the Cap-and-Trade Regulation.

It should be noted that CE2 Carbon Capital submitted two sets of identical written comments on October 15, 2013. As these written comments are duplicative, the response above serves to address both simultaneously.

J-1.6. Multiple Comments: Over the course of our participation in the Technical Working Group tasked with informing the development of the Protocol, we provided input on several ways the Protocol may result in the substantial over- crediting of greenhouse gas emissions reductions. We provided specific recommendations on steps the Board could take to further examine and to remedy each of these issues. We described our concerns in written comments submitted on July 1 and August 22, 2013 to the Board (attached hereto as appendixes) and have raised these concerns within the context of the Technical Working Group meetings and with Board staff outside of those meetings. While we have learned a great deal from these exchanges of information, as of yet, neither the responses published in the Staff Report accompanying the September 4th release of the draft Protocol, nor the draft Protocol itself, have sufficiently addressed these issues. Considering that the MMC Protocol is the first protocol that the Board is developing itself, that it has the potential to generate a large quantity of credits, and that other offsets programs to date have received wide-spread criticism for non-additional crediting, it is especially important that the Board make clear that it has performed analysis and taken measures to ensure that the credits generated by this Protocol will be real and additional.

Finally, given recent assessments of the California market for allowances which suggest that allowance prices are expected to remain close to floor levels almost through 2020, there seems to be no reason for the Board to rush forward with the adoption of a Protocol before it has performed the analysis and modifications needed to be confident that the Protocol meets the requirements of AB 32. (STANFORD 2)

Comment: I'm Barbara Haya, a research fellow at Stanford Law School. Thank you for the opportunity to speak today about the proposal mine methane capture protocol. Over the last six months, as a participant in the Mine Methane Capture Protocol Working Group, I saw Board staff work for make sure the methods of measuring emissions reductions from individual projects under the protocol are accurate. But I'm here today because several broader scale issues remain unaddressed.

And given the seriousness of increasing the coal mine methane projects, I believe more refined and especially transparent analysis is needed by the Board. So I urge the Board to only adopt this protocol and any other new proposed offsets protocols after adequate analysis has been done to ensure the protocol will not infuse California's Cap and Trade Program with substantial numbers of false carbon credits. (STANFORD 3)

> **Response:** ARB appreciates the recognition of its extensive public process in the development of the MMC protocol. As evidenced by this process, the development of a new compliance offset protocol takes considerable time as staff seeks to engage with a diverse set of stakeholders and put forward the best possible protocol that meets the rigorous standards of the Cap-and-Trade Regulation. Contrary to comments that refer to a rushed process or a need to delay the protocol, staff believes they took the appropriate amount of time to properly work through the complexities involved with the development of the MMC protocol and to ensure that the resulting credits represent real, additional greenhouse gas emission reductions that meet the requirements of AB 32. The ARB offset program has not been criticized for non-additional crediting the way some other programs have as cited by commenters. This is due in part to the objective standards-based approach to establish if a project is additional. As in the past, staff started the protocol development process by evaluating existing offset protocols and evaluating their best design features through a public process to develop ARB's version.
>
> The process used to develop the MMC protocol is consistent with the public process required by the Administrative Procedure Act. During the rulemaking process, ARB has endeavored to consider and respond to all comments made during the workshops. There was also extensive discussion about some of the concerns related to the MMC protocol at the October 2013 Board hearing. As with every rulemaking, ARB responds to all comments received during the formal comment periods in the Final Statement of Reasons, which is developed after a Board vote and prior to submittal of the rulemaking package to the Office of Administrative Law.
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> Please note that more detailed responses to the specific issues of additionality policy and allowance price cost containment, as they relate to the proposed MMC protocol, can be found in responses to 45-day comments J-1.16 and J-1.3, respectively.

Perceived Perverse Incentive to Flare Methane

J-1.7. Comment: *Comments on Climate Action Reserve Coal Mine Methane Project Version 2.0 Submitted to CAR*

Dear Ms. Tornek:

The Environmental Law Clinic, part of the Mills Legal Clinic at Stanford Law School, submits these comments to the Climate Action Reserve (the "Reserve") on behalf of Dr. Michael Wara, Associate Professor at Stanford Law School, regarding the Coal Mine Methane Project Protocol, Version 2.0 for Public Comment (the "Protocol").

2. Additionality. The Protocol's Performance Standard Test does not adequately address the possibility that drainage systems have the economically viable option to inject methane into a commercial pipeline, but choose instead to use or flare methane onsite.

We are concerned that some offset projects may be able to switch back and forth between earning offsets under this Protocol and selling methane into a pipeline network. If permitted, this temporal "stacking" would undermine the additionality of the Protocol, and runs counter to principles articulated in other Reserve protocols.[184]

Our concerns arise because the Protocol's eligibility rules allow a drainage system to qualify for offsets by flaring or otherwise using methane, even if selling methane to a pipeline is commercially viable. In other words, the eligibility rules do not include an analysis of the economic viability of injecting methane into a pipeline network. Drainage projects pass the performance standard test simply if they destroy methane "through any end-use management option other than injection into a natural gas pipeline."[185] Remaining eligibility rules require only that that project start dates be no more than three months after the drainage system begins commencing destruction of methane.[186] Under these rules, a drainage system that injects methane into a pipeline would not appear to qualify for offsets if the project developer decides to build a flare or other end-use management application to replace pipeline exports. Assuming the switch happens after three months of injection, it would appear to violate the eligibility rule on timing. However, the eligibility rules allow for multiple drainage systems to exist at a single coal mine, raising the prospect that as new boreholes are drilled as the mine face advances, the mine operator could elect to either create offsets by flaring or sell pipeline gas from new drainage wells.

We would appreciate the Reserve confirming this matter, and suggest further that there is no valid reason to view a project at a mine that has ever injected gas into a pipeline as additional.

Unfortunately, nothing in the protocol rules precludes the reverse ordering: a project that could economically inject methane into a pipeline might choose instead to pursue an on-site activity and earn offset credits. So long as the drainage system does not inject methane into a pipeline network, it is assumed to be additional under the performance standard test.

184 *See, e.g.,* Climate Action Reserve, Rice Cultivation Project Protocol, Version 1.0 § 3.5.3 (prohibiting stacking of ecosystem service payment systems in addition to earning carbon offsets for the same mitigation activities).
185 Protocol § 3.4.2 (based on the analysis in Protocol Appendix A).
186 *Id.* § 3.2.

That assumption is flawed, however, under a variety of plausible economic conditions. Project developers might instead see the Protocol rule structure as giving them the chance to bet long on carbon prices, with a backstop option to sell methane into a pipeline network if carbon prices do not rise as expected. Indeed, the rational project developer considering pipeline sales would be wise to consider whether or not a carbon offset provides a higher value hedge against low gas prices, as Figure 1 demonstrates.

Figure 1: Value of Offset Minus Value of Pipeline Sales ($ per metric ton CH_4)[187]

		CO2 price ($/tCO2-eq.)				Value of natural gas sales
		5	15	25	50	
Natural gas price ($/mmBTU)	2.5	$ (40.58)	$ 141.92	$ 324.42	$ 780.67	$ 131.83
	3.5	$ (93.31)	$ 89.19	$ 271.69	$ 727.94	$ 184.56
	4.5	$ (146.05)	$ 36.45	$ 218.95	$ 675.20	$ 237.30
	5.5	$ (198.78)	$ (16.28)	$ 166.22	$ 622.47	$ 290.03
	6.5	$ (251.51)	$ (69.01)	$ 113.49	$ 569.74	$ 342.76
	7.5	$ (304.24)	$ (121.74)	$ 60.76	$ 517.01	$ 395.49
Value of carbon offsets		$ 91.25	$ 273.75	$ 456.25	$ 912.50	

Each cell in the main table of Figure 1 shows the difference between the value of the carbon offset derived from flaring methane and the value of selling that methane into a pipeline, for a range of natural gas and carbon prices, per metric ton of CH_4. Positive numbers are highlighted and indicate that for the prices applicable in that cell, the carbon offset is more valuable than the direct sale of methane. Thus, under these conditions, a project developer will prefer to generate offset credits rather than sell captured methane into the pipeline network.

For context, the U.S. Energy Information Administration reports that average wellhead natural gas prices in December 2011 were $3.06 per mmBTU; prices since 2000 have generally ranged from $2.5 to $7.5 per mmBTU, with a few higher spikes.[188] A carbon price of $5/t$CO_2$e is a reasonable approximation of the voluntary carbon market, whereas estimates of California's compliance costs are bounded by the remaining prices shown here.

We note that at current forward delivery prices for CCAs ($14.80 for Dec 2013 delivery),[189] current compliance grade carbon prices would tend to push a coal mine to orchestrate a switch to selling offsets from selling pipeline gas.

The net effect of these incentives is to undermine a key assumption in the Protocol's additionality calculations. By defining the performance standard test for drainage systems as any control technology that does not involve pipeline injection, the Protocol

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187 Source: authors' calculations using flaring as an example offset project. Assumptions: 52.73 mmBTU per tCH_4 and 18.25 tCO_2e avoided per tCH_4 destroyed (using GWP and "r" values from Protocol equations 5.5 and 5.9, respectively); prices as shown in chart.

188 Energy Information Adminstration, U.S. Natural Gas Wellhead Price (March 25, 2012), available at: http://www.eia.gov/dnav/ng/hist/n9190us3M.htm. EIA reports December 2011 prices were $3.14 per thousand cubic feet of natural gas. At 1.025 mmBTU per thousand cubic feet of natural gas, this price is equivalent to $3.06 per mmBTU

189 *See* PointCarbon, Carbon Markets North America, 23 March 2012, *at* 2.

implies that pipeline sales are already economically viable and that all projects not, injecting into pipelines do not find it viable to do so.[190] The calculations presented in Figure 1 contradict this assumption and demonstrate that a rational project developer might prefer to pursue carbon offsets above pipeline sales, with the option to exit the Protocol and sell methane into a pipeline if relative carbon and natural gas prices do not justify the pursuit of offset credits. Indeed, the rational project developer might well prefer to view the Protocol as a hedge against low natural gas prices.

This situation is problematic and undermines the actually additionality of the Protocol. We recommend the Reserve revise the Protocol to prohibit switching from offset credits to pipeline sales, and vice versa.

Our understanding of VAM mitigation technologies is that no rational project developer would seek to invest in the capability to convert ventilation air (less than 1% methane) into pipeline quality gas (90-95% methane).[191] This investment would be necessary to create the option for temporal stacking described above. Thus, our concern applies only to drainage systems. (STANFORD 2)

> **Response:** These comments were originally submitted in response to a voluntary market offset protocol developed by the Climate Action Reserve. As described in the 2011 FSOR for the rulemaking to consider the Cap-and-Trade Regulation[192], ARB allows emission reductions achieved under approved offset quantification methodologies to be issued ARB offset credits.
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> The regulation includes provisions to allow early action offset credits from approved early action programs and quantification methodologies to be credited as ARB offset credits and used in the Cap-and-Trade Program. ARB included these provisions to allow parties to develop offset projects and purchase offset credits that are being issued by Early Action Offset Programs. These provisions were added to provide parities the opportunity to participate in the offset market while ARB is finalizing the

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190 Protocol Appendix A draws erroneous conclusions to support the proposition that drainage systems using non-pipeline control technologies are always additional. Specifically, Appendix A concludes that the paucity of non-pipteline control technologies reflects their being uneconomic generally, rather than being less economic than pipeline injection. According to Appendix A, only four of twelve drainage systems that do not have a pipeline interconnection employ an alternative mitigation technology. Of these four projects, two are at mines that also have pipeline injections; the analysis excludes these two projects, and focuses only on the two remaining projects that use methane at mines where no pipeline interconnection is present. On this basis, Appendix A concludes that "on-site end use projects are uncommon even at mines that do not sell their [methane] to pipelines . . . this finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects." To the extent two drainage projects permit any valid basis for establishing *ex ante* additionality criteria, a more appropriate conclusion would be that the data cannot rule out the alternative hypothesis that pipeline injection is generally more economic than alternative mitigation measures. The difference matters because the first erroneous conclusion supports the Protocol's additionality criterion (which Figure 1 contradicts), whereas the second conclusion is consistent with both the data in Appendix A and the calculations in Figure 1

191 C. Özgen Karacan et al., *Coal mine methane: A review of capture and utilization practices with benefits to mining safety and to greenhouse gas reduction*, 86 INTERNATIONAL JOUNRAL OF COAL GEOLOGY 121, 147 (2011) (reviewing VAM characteristics and typical pipeline injection standards), *available at:* http://www.epa.gov/cmop/docs/cmm-paper-2011.pdf.

192 California Air Resources Board. Final Statement of Reasons. October 2011. http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

regulation and taking the necessary implementation steps needed to have a fully functioning ARB offset program and offset tracking system.[193] Staff recognizes that some of the content is relevant to the proposed ARB compliance offset protocol and a more detailed response to the specific issue of the perceived perverse incentive to flare methane, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.8.

J-1.8. Comment: Conflicting incentives: Incentives created by the Protocol may cause mine owners to flare methane that would have been injected into a pipeline in the absence of the Protocol.

> **Recommendation:** The Protocol should either include refined eligibility criteria for projects at new underground mines and at underground mines that have undergone major modification to avoid these "perverse incentives," or new and majorly modified active underground mines should be excluded outright.

If the Board sets eligibility thresholds for pipeline injection projects, the Board should also set eligibility thresholds for all other types of methane destruction projects that are at least as stringent as those for pipeline injection in order to avoid crediting non-additional activities and to avoid creating incentives to waste natural resources.

In Appendix A, we assess the use of thresholds for determining the eligibility of pipeline injection projects. The Board has discussed the possible use of eligibility thresholds for pipeline injection, but not for other project types that use drainage-mine methane. We urge the Board to set eligibility thresholds for all project types in order to avoid crediting non-additional activities. For example, if no eligibility threshold is set for flaring projects, but pipeline injection eligibility is restricted based on a threshold, then the activity of flaring drainage-well gas which exceeds the threshold could be (1) eligible for credits, but (2) non-additional. Flaring such gas would be non- additional because the gas could be profitably sold into a pipeline in the absence of any offset credits.

Furthermore, crediting this non-additional activity would quite likely occur under plausible pricing scenarios. At today's natural gas prices (around $3.50 per MMBTU) and at a carbon offsets price of $15 per tCO_2e, destroying methane by flaring could generate more income for the mine than selling methane into a pipeline, inducing mine operators to opt for flaring rather than pipeline injection. So as not to incentivize mine owners to flare methane that they otherwise would have sold through the natural gas pipeline system, it is critical that eligibility thresholds be set for *all types of projects* that destroy drainage well methane at levels at least as stringent as those for pipeline injection. While the Board's Protocol could exclude flaring from eligibility at mines (or wells) where injection is already occurring, our concern lies in the financial incentives presented to a mine owner upon mine expansion, the drilling of new gob wells, or the development of a new underground mine.

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[193] California Air Resources Board, Final Statement of Reasons for the rulemaking to consider the adoption of a proposed California cap on greenhouse gas emissions and market-based compliance mechanisms regulation, including compliance offset protocols, 2011, p. 847. http://www.arb.ca.gov/regact/2010/capandtrade10/fsor.pdf

Second, at current natural gas and carbon allowance prices, a mine operator would receive more revenue by selling offsets credits generated from flaring leaking methane than from selling that same methane into a natural gas pipeline (a project-type which is ineligible for offset credits because it is already considered common practice). This means that the Protocol would incent operators of new underground gassy mines or newly modified mines that would have otherwise chosen to inject their methane into a pipeline under business-as-usual to choose instead to flare the methane to earn offset credits. This would not only result in substantial non- additional crediting (methane destruction would be credited that would have happened through pipeline injection without the offsets protocol); it would also mean that methane is flared that would otherwise have been put to productive use.

At current natural gas and offsets prices, the offsets protocol creates a direct financial incentive for mine operators at new or expanded mines to flare methane instead of injecting their methane into a pipeline – a very real direct potential adverse effect of the protocol.

There is a simple, straight-forward solution to both of these risks. Both issues apply only to new underground mines and major modification to existing active underground mines. Both issues can be avoided by carefully defining project eligibility criteria to avoid crediting mines where pipeline injection is feasible. Alternatively, these issues can be avoided by making drainage methane from new and majorly modified underground mines ineligible under the Protocol. Even if the Board decides to exclude these mines or mine expansions now, it can choose to include all or a subset of them in the future, after there is more clarity with regard to if natural gas prices increase in a sustained manner.

1. We offer one suggested modification to the discussion draft protocol that we believe will simultaneously address two of the concerns we have raised. We suggest making projects that capture drainage methane from *new* underground mines and new major modifications to existing active underground mines ineligible under the Protocol. Doing so would avoid the risk that new mines and wells that would have chosen to inject their mine methane into a pipeline would choose instead to flare their methane to earn the greater income from selling offsets credits at recent natural gas and allowance prices. Projects that capture methane from drainage wells at new and major modifications to active underground coal mines should be considered ineligible under the Protocol
A second potential perverse incentive that could result from the Protocol can be solved by the same exclusion. We recognize and appreciate that the Board has determined that pipeline injection is common practice at active underground mines with drainage wells and is therefore treated as non-additional. We also recognize that flaring or other destruction of methane from wells where injection had previously taken place is also ineligible for crediting under the Protocol. Our comments here apply again, as above, to newly installed drainage systems at *new* underground mines and *new* major modifications to existing active underground mines, where new mines and new major modifications are defined as those that start production *after* the adoption of the Protocol. At recent natural gas and carbon allowance prices, a mine operator would

receive greater income from offsets for flaring methane from drainage wells than from selling that methane into a natural gas pipeline. This means that operators of new underground gassy mines or newly modified mines that would have otherwise chosen to inject their methane into a pipeline in the absence of the Protocol might instead choose to flare the methane to earn carbon credits. This would not only result in substantial non-additional crediting (methane destruction would be credited that would have happened through pipeline injection without the offsets protocol); it would also mean that methane is flared that would otherwise have been put to productive use.

Due to the relatively slow rate at which new underground mines are built and expanded, it is expected that the majority of credits potentially generated under the active underground mine portion of the Protocol will be from existing mines.

However, it is also important to note that coal mines still are being built and expanded. For example, new mining at Alabama's Blue Creek seam, one of the country's most gassy coal seams, is being planned,[194] and if built, would face both of the incentives described just above.

ARB staff response to these concerns: These issues were not addressed in the *Staff Report* nor by the Protocol. (STANFORD 2)

> **Response:** As mentioned in the comment, pipeline injection was excluded as an eligible end-use management option for active underground mine methane drainage activities as it was determined that pipeline injection was common practice at underground mines with drainage systems. This method of destruction was therefore deemed not additional. Staff agrees with the commenter that if mine methane that would otherwise be injected into a pipeline was sent to an alternate destruction device eligible under the MMC protocol that this would not represent an additional reduction. For this reason, the active underground mine methane drainage section of the MMC protocol explicitly prohibits gas from a methane source that was previously sent to pipeline from being eligible for crediting via any end-use management option. This provision serves the dual purpose of keeping out non-additional methane destruction as well as preventing the switching back and forth between the selling of natural gas via pipeline and the destruction of methane via another device to generate offset credits. This is to ensure that project operators do not switch back and forth between these revenue sources as prices fluctuate.
>
> The comment specifically calls into question the decision making process for project developers at new mines, mines undergoing major modifications, and new gob wells. First, it should be understood that the drilling of new gob wells is routine as part of the normal mining process at active underground mines. The MMC protocol does not place restrictions on the drilling of additional gob wells as they can serve an important role in properly ventilating the underground workings

[194] http://walterenergy.com/operationscenter/jwr.html (accessed 17 October 2013)

of the mine. Moreover, gas extracted from gob wells is often of a quality and concentration less than suitable for pipeline injection.

For new mines and those undergoing major modifications, where there is no precedent of pipeline injection, the comments suggest the use of eligibility thresholds for all end-use management options and the setting of more stringent eligibility thresholds for flaring than other eligible options. While staff agrees that use of methane over flaring is preferable, it is not always workable. Staff spent substantial time considering the application of eligibility thresholds for various destruction activities and discussed such ideas publicly in the technical working group setting. It became evident to ARB staff, given the constraint of limited data and the variability of methane content and flow rates at mines, that any attempt to develop standardized eligibility thresholds would result in arbitrary restrictions and problematic project implementation. Comments written during this period of MMC protocol development propose that if thresholds are developed for pipeline projects that other destruction methods should also have thresholds at least as stringent as those for pipeline injection. Without the ability to set thresholds to determine the additionality of pipeline injection, destruction via this method was deemed ineligible. Developing thresholds for other end-use management options are as, if not more, infeasible than for pipeline injection given the even smaller pool of data.

The commenter suggests that if thresholds are not applied, that new mines and those undergoing major modifications should be excluded outright from the MMC protocol based on the assumption that such mines would inject into pipeline without the existence of the MMC protocol. Staff does not agree with those assumptions for the same reasons that establishing eligibility thresholds is not practical. Staff cannot predict if a mine would or would not send gas to a natural gas pipeline and as such the MMC protocol only assesses past actions. Like mines that are currently operating, new and expanding mines will not be able to switch between offset production and pipeline injection; operators will need to make a decision at the outset.

Staff disagrees with the comment suggesting that the MMC protocol incentivizes "unproductive" use via flaring over "productive" use such as pipeline injection. The assertion is based on the belief that the flaring of captured methane as allowed for under the MMC protocol would be a more profitable venture than selling the mine methane via injection into a natural gas pipeline. Staff conducted analysis comparing the revenues generated from pipeline injection and offset sales and found that, under plausible pricing scenarios, the difference between the revenue streams to be slight and variable. From the sources relied upon by the commenter,[195] over the last ten years for which data is available

[195] Specifically, the commenter cites to: U.S. Energy Information Administration, U.S. Natural Gas Wellhead Price (2014) http://www.eia.gov/dnav/ng/hist/n9190us3a.htm

natural gas prices have fluctuated between $2.66 and $7.97 per 1,000 scf with a ten year average of $5.30 per 1,000 scf. The table below shows the value of 1,000 scf natural gas at various offset prices, assuming 90% methane concentration of natural gas (1,000 scf CH_4 represents 0.4027 tCO_2e[196]).

Price of Offset/tCO_2e	Offset Value of 1,000 scf Natural Gas
$5	$1.81
$10	$3.62
$15	$5.44
$20	$7.24

Current offset prices are approximately $10/$tCO_2e$. This price will vary based on a number of factors but a range of $5 to $20 is an appropriate estimate over the course of the next ten years. A comparison of offset and gas sale revenue shows no clear financial incentive for a project developer to choose flaring for the purpose of offset generation over pipeline sales. These are complex markets subject to unpredictable fluctuations in price. Only in retrospect will potential project developers, ARB staff, and the commenter know whether the choice to generate offset credits or sell natural gas was a more profitable option.
Staff would also prefer to see captured mine methane used productively rather than flared. In fact, multiple productive end-uses other than pipeline injection are eligible destruction methods under the MMC protocol. Nonetheless, the primary goal of the MMC protocol is to incentivize the destruction of mine methane that would otherwise be vented into the atmosphere. Depending upon the quality or quantity of the gas or the terrain where the mine is situated, flaring is the only feasible destruction option and flaring is certainly preferable to methane being freely emitted. As previously mentioned, developing eligibility thresholds for flaring proved impractical.

During the MMC protocol development process, ARB has endeavored to consider and respond to all comments made during the technical working group meetings and workshops. There was also extensive discussion about some of the concerns related to the MMC protocol at the October 2013 Board hearing. As with every rulemaking, ARB responds to all comments received during the formal comment periods in the Final Statement of Reasons, which is developed after a Board vote and prior to submittal of the rulemaking package to the Office of Administrative Law.

Please note that a more detailed response to the specific issue of additionality policy, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.16.

[196] U.S. EPA Coalbed Methane Outreach Program (2004) Methane Emissions from Abandoned Coal Mines in the United States: Emission Inventory Methodology and 1990-2002 Emissions Estimates (as referenced in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at pp. 10-11, *available at* http://www.epa.gov/cmop/docs/amm_final_report.pdf).

Perceived Conflicts with Federal Regulations

J-1.9. Multiple Comments: At the meeting each of you asked probing questions which we would like to take the time to respond to more fully than we did in person. Below we list some of the questions you asked last week, followed by considered answers which we hope may further clarify the reasons for our concerns and recommendations. These answers are described in more detail in the formal comments we are submitting on the draft Protocol, but we thought it might be helpful to provide some direct answers to the questions you raised.

We also discussed the recommendation to exclude all new active underground mines and all active underground mines that have undergone major modification from participation in the Protocol. This recommendation was made to avoid conflicts with the Clean Air Act and to avoid incentivizing flaring at mines that would have pipeline injected without the offsets protocol. But wouldn't these projects, incented by offsets, help establish the case that MMC should be considered BACT (Best Available Control Technologies)? And aren't we just speculating about future EPA regulation that will take years to happen?

First, we should be clear that new and expanding mines are currently required, under EPA's New Source Review permitting procedures and Tailoring Rule, to obtain Prevention of Significant Deterioration (PSD) permits. We agree with the Board that no mines have yet to seek these permits nor would the permits on their face constitute a legal requirement to destroy methane emissions. Such a legal requirement would only occur if a state implementing the PSD permit made a determination that methane destruction was the Best Available Control Technology (BACT).

Due to the relatively slow rate at which new mines are built and expanded, it is expected that the majority of credits generated under the active underground mine portion of the Protocol will be from existing mines rather than new mines or new mine extensions. By incenting the development of MMC projects at existing mines, the Protocol helps generate experience with MMC technologies that will encourage MMC to be considered BACT. We agree with the Board that this positive influence of the Protocol on policy implementation is a form of positive leakage – emissions reductions supported by the Protocol but not credited under the Protocol. However, because of the relatively small proportion of new and expanding mines expected to participate in the Protocol, excluding these mines, we understand, should not substantially weaken this positive leakage effect.

Are new underground mines actually opening and expanding? New mining at Alabama's Blue Creek seam, one of the country's most gassy coal seams, is being planned. If built, this project would require a PSD permit and would have incentives to flare methane instead of injecting it into the pipeline because flaring should generate more income than pipeline injection, even though other mines in the immediate vicinity are already injecting methane into a pipeline. http://walterenergy.com/operationscenter/jwr.html

Though Patriot Coal is generally slowing down its operations and closing mines, it did open one new underground coal mine – Peerless mine – In West Virginia in 2012. http://www.patriotcoal.com/index.php?view=appalachia-operations&p=3&s=51 (STANFORD 1)

Comment: Secondly, there is a risk of weakening implementation of the Clean Air Act rules with respect to greenhouse gas emissions from new and expanded coal mines. This can be solved by refining eligibility criteria by this relatively small portion of possible participating projects, at least until there is more certainty about what these Clean Air Act rulings will look like. (STANFORD 3)

> **Response:** ARB staff considered the concerns raised in these comments and others similar to them and provided a detailed response in Attachment A: Response to Comments on the Environmental Assessment Prepared for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms.

No Conflicts with Federal Regulations

J-1.10. Multiple Comments: RCE would also like to address certain areas of concern raised by other interested parties relating to the exclusion from the Protocol of all mine methane emissions (both regulated and unregulated) at new mines and major modifications at existing active underground mines that are or may be subject to EPA and state regulation under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Best Available Control Technology ("BACT") programs.

By its terms the Protocol successfully navigates through the concerns around PSD and BACT by requiring as a condition precedent a legal standard that all qualifying emission reduction activities must be both "voluntary" and "outside the requirements of federal or state laws, regulations, or mandates." ARB's Compliance Offset Program and the Protocol are unequivocally clear that emission reductions within regulated thresholds are not additional and do not qualify for allowances or offsets. Moreover, as proposed the Protocol will not undermine implementation of the Clean Air Act or any other environmental laws concerning the regulation of specific volumes of mine methane emissions. In fact, RCE believes quite the opposite – MMC projects developed as a part of AB 32 could accelerate the development of new technologies that will help establish eventual BACT for underground coal mines. Furthermore, methane emissions from surface mines and abandoned mines are considered fugitive emissions and not regulated under the Clean Air Act.

In addition to the comments noted above, as ANSI-certified GHG offset validators and verifiers, RCE can speak to the fact that procedurally the verification of real, permanent and additional mine methane emission reductions under the Protocol will involve the netting of all legally required emission reductions. Emission reductions required by law would not pass the Protocol's Legal Requirement Test and therefore could not be verified, removing the risk that these non-additional offsets would be created. Thus all unregulated mine methane emissions, such as emissions either: (a) under applicable PSD and state thresholds for new mines or major modifications of existing underground mines, or (b) in excess of emission reductions accomplished by BACT, should fall within the scope of the Protocol. Simply to ignore “known, quantifiable, and real” unregulated mine methane emissions would be contrary to the Board’s clear goals and objectives in developing both the Protocol and California’s GHG offset market. (RCE 1)

Comment: Second, the expectation that forthcoming EPA regulations will obviate the need for the MMC protocol is unfounded as those proposed regulations focus on emissions from power plants and do not include any restrictions on emissions from coal mines. Further, the objection ignores the fact that the draft compliance protocol and early action protocols for MMC require projects to demonstrate regulatory surplus, which means that projects would not be eligible if and when capture of mine methane becomes required by law and/or regulation. (VCS)

Comment: The MMC protocol is an example of California’s climate leadership. Beyond the worthy task of crafting this protocol, this is a work product which can be leveraged and adopted by other jurisdictions. The MMC protocol can result in real emission reductions even beyond the California cap-and-trade program- which is, at its heart, the essence of climate leadership.

In closing, SCE would again like to thank the California Air Resources Board for their work on the Mine Methane Capture offset protocol, and voice our support for its inclusion in the Cap-and-Trade Regulation. (SCE 2)

Comment: We think the protocol could help see more of these projects roll out in the future and really have a positive impact on eventual regulation and BACT for coal mine methane emissions. But currently, the technology is in its infancy in its application for coal mine methane emission. There's only ten of these projects worldwide and there are severe limits on the ranges in which they can operate. Currently, two-thirds of the coal mines in the U.S. that are gassy are below .3 percent methane where these projects can't be deployed. Many of the projects are above the flows that are limited to this technology. So we feel like by using this vehicle of offset mechanisms, we can see many of these projects be rolled out and the technology become more mature so it can actually accelerate BACT feature. (RCE 2)

Comment: This could encourage other states to pay more attention to methane emissions both from mines and in general. And perhaps other states even could be encouraged to look positively at participating with California and Quebec and the Western Climate Initiative or some other type of program. (VESSELS 2)

Comment: California can and should accept MMC offsets into its ARB Cap-and-Trade Program. While we have begun to discourage coal use and emissions within California, the stat can play a role in influencing appropriate policy outside of our state borders. (CE2CAPITAL 1)

Comment: My second point is leadership. And I really think that if this protocol is adopted, it's something California should be proud. Of last time I read the paper, the coal mine industry is not doing very well across the United States. I think the Air Resources Board has played a key role, whether it renewable portfolio standards, clean cars, et cetera. This protocol you cannot have an influence in other states, but you can have some voluntary efforts in coal mines across the United States. I think it's something that ARB should be proud of to be able to highlight the fact there's over 70 million tons of methane being released from coal mines across the United States each year and not much is being done about it. So I would agree with NRDC and many other parties something needs to be done with this nationally. This is a great pathway to try to help in that effort and send a signal to the U.S. something needs to be done. (CE2CAPITAL 3)

Comment: Indirect Benefit of Improved MMC Data Quality: The inclusion of MMC projects into the CARB GHG Cap and Trade Program will result in better data collection by mines with use/destruction projects in place (or in the planning process). This will contribute to the body of publically available MMC project data and add to our understanding of this GHG emission source. (EPA 1)

> **Response:** ARB staff agrees the adoption of the MMC protocol is likely to lead to advancements in mine methane capture and destruction technologies as well as the further deployment of such technologies. We expect progress in this field to result in strengthened state Best Available Control Technologies (BACT) determinations. A more detailed response to the specific issue of perceived conflicts with federal regulations, as it relates to the proposed MMC protocol, can be found in Attachment A: Response to Comments on the Environmental Assessment Prepared for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms. Please note that a more detailed response to the specific issue of the perceived perverse incentive to flare methane, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.17.
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> *It should be noted that CE2 Carbon Capital submitted two sets of identical written comments on October 15, 2013. As these written comments are duplicative, the response above serves to address both simultaneously.*

Legal Requirement Test

J-1.11. Comment: In addition to the above, we recommend two other changes to the Protocol that would help avoid conflict with the Clean Air Act. First, we comment on this paragraph in the Protocol:

> Emission reduction achieved by an MMC project must also exceed those required by any law, regulation, or legally binding mandate at the time of offset project commencement. If no law, regulation, or legally binding mandate requiring the destruction of methane at the mine at which the project is located

exists at the time of offset project commencement, all emission reductions resulting from the capture and destruction of mine methane are considered to not be legally required, and therefore eligible for crediting under this Protocol, subject to the performance standard evaluation above. (page 8)

We highlight the phrase “at the time of offsets project commencement.” If mine methane capture were to become legally required in the middle of an offsets crediting period, such as through enactment of new Clean Air Act regulations, then any MMC project should cease to be allowed to generate offsets credits from the date when the MMC project is legally required to be implemented. Non-additional credits would be generated if a mine is allowed to generate offsets credits after MMC is legally required at the mine, even if that law was not in effect at the start of the MMC project. (STANFORD 2)

Response: The legal requirements test is applied to potential MMC projects in the same fashion as other ARB offset project types. Legal requirements are assessed at the time of project commencement and again at time of crediting period renewal. Like other non-sequestration compliance offset protocols, the crediting period for the proposed MMC protocol is ten years. Staff believes that this is sufficient time needed to make an investment attractive for most MMC projects.

The concept of a crediting period is found in several regulatory and voluntary offset programs around the world. The crediting period refers to the period that an offset project is allowed to be issued compliance offset credits. Offset project developers need a guarantee of return on their investment. The most efficient way to do this is to establish a crediting period in which the emission reductions or removals from their projects will be eligible for offset credits. Without certainty about a project’s life span, there may be too much risk for a project to attract investors. Therefore, staff understands there must be some guarantee that the emissions reductions achieved according to a protocol will be eligible to generate offset credits for a known period. However, some types of offset projects could no longer be valid for generating offset credits in the future. This could be because the offset projects have become non-additional because business practices change or the sources are newly subject to direct regulation. ARB’s offset program is designed to balance between guaranteeing investment certainty and allowing ARB to update methods and quantification, as well as to reevaluate and readjust baseline and additionality requirements in protocols in the future. Offset projects will only qualify for renewed crediting periods if they continue to meet the requirements for additionality.

J-1.12. Comment: Section 3.4.1 Legal Requirement Test

Issue: The Legal Requirement Test allows for crediting of emission reductions that are "in excess" of what is required to comply with any legally required emission reductions. In principle, it may be appropriate to credit emission reductions in excess of what is required by law, but in practice, it may be difficult to determine what the effects of legal requirements are on baseline emissions. Different kinds of legal requirements could affect the baseline in different ways, and it is likely that legal mandates stemming from BACT determinations could be highly site-specific, making it difficult to provide standardized guidance for determining what is "in excess" of the legal requirement. In particular, if a certain level of methane destruction is legally required, much of the capital investment needed to capture and destroy methane may be made to comply with this legal requirement. In this case, any "excess" reductions may not face the same barriers as capture and destruction activities at mines that are not legally required to reduce emissions. Any guarantee of eligibility under the protocol should be contingent upon what ARB determines is "in excess" of the legal requirements, and not simply the legal requirement itself.

ARB staff has included language in the protocol that seeks to revise baseline emissions according to historical destruction levels achieved to meet a recent (less than three-year-old) legal requirement. It is not clear that this provision would sufficiently address situations where a new project is implemented immediately after a new legal requirement takes effect. ARB may wish to reserve the right to make determinations about what reductions are "in excess" of legal requirements on a case-by-case basis, or update the protocol once new requirements (e.g., BACT standards) are promulgated. (CAR 1)

> **Response:** Chapter 5 of the MMC protocol provides explicit instructions on how to determine baseline emissions for each type of project activity. The text was carefully crafted and modified to provide a standardized approach for determining what emission reductions are legally required for any given site. Staff does not foresee complications in determining what quantity of emission reductions are in excess of any applicable emission reduction mandates. Nonetheless, ARB is committed to monitoring changes in the regulatory landscape and evaluating their impact on the MMC protocol.
>
> The crediting of emission reductions at mines where capital investment in technologies used to capture and destroy methane have already been made does not conflict with the Cap-and-Trade Regulation as a financial additionality test is not required. In developing the Cap-and-Trade program, ARB instead opted to pursue the performance standard approach. This approach streamlines the calculation of project baselines and determination of the additionality of projects by using standard eligibility criteria that ensure projects are additional. By establishing the standardized criteria in the Compliance Offset Protocol, there is less subjectivity by verifiers or offset project developers as to whether a project may be additional and this supports consistent quantification rigor in the offset program.
>
> Please note that more a detailed response to the specific issue of additionality policy, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.16.

Additionality of Surface Mine Projects

J-1.13. Comment: Section 2.3 Active Surface Mine Methane Drainage Activities
Issue: Eligibility of drainage activities at a surface mine is only limited by timing and not by existing recovery activities at the mine/in the region.

The protocol limits qualifying devices to those destruction devices that were not operating at the mine prior to offset project commencement. What the protocol does not yet appear to address is what other methane recovery activities were occurring at the surface mine prior to project commencement. We note that the U.S. EPA released a report in 2008 on U.S. surface coal mine recovery opportunities[197] and identified the Powder River Basin (PRB) as the most promising coal basin for potential mine-specific methane recovery project opportunities. The report describes how, generally, surface mines are not a large source of methane emissions because of the relatively low gas content of coal that is mined. However, the PRB is an exception and has been the focus of very significant coalbed methane development efforts since the 1990s, with estimated methane reserves of 25 trillion cubic feet. The number of producing coalbed methane wells climbed to 21,000 by the end of 2004, while in the mid-1990s, the basin had only 4,000 wells. As these numbers illustrate, coalbed methane development in the PRB has significantly grown. Thus, one might expect the industry in this region to continue to grow even without the incentive provided by the offset market. We would suggest a deeper analysis of this issue.

The EPA report profiles the ten gassiest surface mines in the U.S., all of which are located in the PRB. About half of these surface mines have estimated CMM emission rates in the same range as active underground mines that are currently recovering CMM and sending it to pipeline and are thus ineligible under the both the Reserve's CMM protocol and under ARB proposed MMC protocol.

Ten Gassiest U.S. Surface Mines

Mine Name	2007 Estimated CMM Emissions (million cf/day)
Rosebud	1.38
Eagle Butte	2.74
Buckskin	2.77
Belle Ayr	2.92
Caballo	3.42
Antelope	3.78
Jacobs Ranch	4.18
Cordero Rojo Complex	4.44
Black Thunder	9.45
North Antelope Rochelle	10.03

Active Underground Mines with Pipeline Projects[198]

197 U.S. EPA, *U.S. Surface Coal Mine Methane Recovery Project Opportunities* (July 2008); available at http://www.epa.JWV/cmop/rsources/active_surface_mines.html.

198 U.S. EPA, *Identifying Opportunities for Methane Recovery at U. S. Coal Mines: Profiles of Selected Underground Coal Mines 2002-2006* (January 2009); available at http://www.epa.gov/cmop/resources/active_underground.html.

Mine Name	2006 Estimated CMM Emissions (million cf/day)
Shoal Creek	4.7
Loveridge No. 22	7.1
Emerald	7.4
Oak Grove Mine	7.5
Blue Creek No. 5	9.4
Blacksville No. 2	9.7
Pinnacle	9.8
Cumberland	10.1
West Elk Mine	18.2
VP8	19
Blue Creek No.4	23.2
Blue Creek No. 7	31.6
Buchanan Mine	72.3

The protocol states that pipeline injection of mine methane extracted from methane drainage systems at active underground mines is common practice and considered business-as-usual, and, therefore, ineligible for crediting under this protocol. Based on the data above, existing recovery activities that are occurring at gassy surface mines would seem to raise concerns similar to those for recovery activities that are occurring at gassy active underground mines. In particular, existing CBM and CMM recovery in the PRB raises concerns that some recovery activities within the PRB and/or at gassy surface mines could be financially viable without the incentive from the offset market and therefore non-additional, despite being a relatively uncommon practice when viewed across the entire United States.

ARB's staff report states that few active surface mines currently capture and destroy mine methane, and thus methane capture and destruction is deemed not to be business-as-usual, which implies that active surface mine methane drainage activities are additional. However, this may be too broad a characterization under certain circumstances. In particular, at surface mines where recovery of methane is already occurring, simply adding a new destruction device may not be enough to demonstrate additionality, especially for projects located at gassy surface mines like those found in the PRB.

Section 5.2 (b) of the MMC protocol excludes from eligibility methane from specific sources (e.g. pre-mine wells) at *active underground* mines that historically sent any methane from that source to a natural gas pipeline, or begins to inject methane from that source into a pipeline while the offset project is ongoing. The same approach may be warranted for surface mines to ensure the additionality of offsets from these projects. (CAR 1)

> **Response:** The commenter's analysis of the prevalence of methane capture in the Powder River Basin conflates the extraction of coal bed methane (CBM) and the capture of surface mine methane from drainage systems. The extraction of

coal bed methane, the methane-rich natural gas drained from coal seams and surrounding strata not disturbed by mining, is not eligible under the MMC protocol, which only credits the destruction of methane from drainage activities at active surface mines. While the commenter points to the comparable emission rates of the ten gassiest surface and underground mines in an effort to show that these extremely gassy surface mines could support pipeline injection, we have yet to see comparable mine methane project rates at surface mines. Only one of the ten gassiest surface mines has a methane capture project in place. This is representative of the lack of mine methane drainage activities at active surface mines eligible for crediting under the MMC protocol. In fact, the EPA report cited in the comment was developed for the stated purpose of encouraging the development of projects aimed at the recovery of surface mine methane to complement the Powder River Basin's flourishing coal bed methane industry.

The comment also questions the inclusion of pipeline injection as an eligible end-use management option for active surface mines when it was deemed ineligible for active underground mine. When examining the level of penetration of pipeline injection technologies at active underground mines, a smaller population of active underground mines with existing methane drainage systems was evaluated because the installation of methane drainage systems is considered a compliance response to regulation requiring that methane levels be kept below one percent in mine working places and intake air courses.[199] There is no such regulatory requirement for active surface mines and thus examining subsets of abandoned mines is not warranted. The ability of surface mines to inject drained methane into a pipeline based on sufficient emission rates is different in principle from observing the practice actually being implemented at surface mines.

We see a similar phenomenon with regard to the financial viability of methane capture at surface mines without carbon finance. Staff recognizes that pipeline injection, like other eligible end-use management options that result in energy production, can, in some circumstances, be financially viable without carbon finance. This does not conflict with the Cap-and-Trade Regulation as a financial additionality test is not required. In developing the Cap-and-Trade Program, ARB instead opted to pursue the performance standard approach. This approach streamlines the calculation of project baselines and determination of the additionality of projects by using standard eligibility criteria that ensure projects are additional. By establishing the standardized criteria in the Compliance Offset Protocol, there is less subjectivity by verifiers or offset project developers as to whether a project may be additional and this supports consistent quantification rigor in the offset program. Given the lack of projects carrying out surface mine methane drainage activities, staff is confident that the MMC protocol promotes activities that will result in offset credits that are additional.

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199 Title 30, Code of Federal Regulations, 75.323, 2006(as cited in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 3, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf.

Please note that a more detailed response to the specific issue of additionality policy, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.16.

Additionality of Abandoned Mines

J-1.14. Comment: Ruby Canyon Engineering Inc. (RCE) hereby respectfully submits these comments for your consideration in support of the above-referenced Protocol. These comments are restricted to further analysis of abandoned mine methane (AMM) project additionality and potential emission reductions associated with AMM project development.

Table 1 (at the end of the document) lists the methane recovery projects believed to be currently active in the United States sorted by project developer. Thirty-eight mines are involved in drainage activities. There are 12 project developers. Of those twelve project developers two are mining companies; Consol Energy (11 mines) and Walter Resources (2 mines). Of those 13 mines all but three were continuation of methane drainage for pipeline sales that were active prior to mine abandonment. The Blue Tip Energy project is a continuation of drainage after abandonment for gas sales but was developed by an independent project developer and not a mining company. Blue Tip Energy has registered Verified Carbon Units (VCU) under the Verified Carbon Standard (VCS) protocol VRM0002 which was based on a modification of the Clean Development Mechanism methodology ACM0008.

The project developer DTE Methane drains gas from 11 mines contiguous with each other networked together by pipelines and compressors. The gas is treated to remove water, oxygen, hydrogen sulfide, carbon dioxide and nitrogen prior compression and sale to an interstate pipeline. These mines were abandoned from 1950 to 1998 and the project was initiated in 2002 by Illinois Methane which ceased operations in 2004. The project was inactive for about a year after which DTE Methane purchased and retrofitted the project for the reduced production rates realized after the first two years of production. DTE Methane has also registered VCUs with VCS. Recently DTE Methane sold the project to Keyrock Energy who has also recently registered VCUs with VCS. The other primary developer of AMM recovery projects is Grayson Hills Farms which has aggregated approximately 8 mines in the Illinois basin and is processing the gas for CNG vehicle fuel, power generation and pipeline sales. The rest are small developers of which very little is known.

RCE modeled the credits (using the decline curve method) that would have been generated had the draft ARB MMC protocol been in effect in year 2000. The analysis assumed that the projects started in 2000 or later had started in 2000 (except for the cases where the mine was abandoned after 2000).

Table 2 shows that of the 27 mines capturing methane since 2000, four were a continuation of an active MMC project selling gas to a pipeline: Blue Creek #3 and Blue

Creek #5 (Walter Energy), VP 8 (Consol Energy) and Aberdeen (Blue Tip Energy). The yearly emission reductions based on the draft protocol baseline decline curve were calculated based on the EPA initial emission rate for these mines (mines closed before 1971 have no emissions data so were not used). The last column in Table 2 shows yearly average methane capture in tCO2e from 2000 through 2013. Note that the four highest emission reductions occurred at the four mines that had been selling gas to a pipeline prior to closure. Should it be decided that continuation of the use of a non-qualifying destruction device after mine closure disqualifies that methane drainage project from participating in the ARB offset market (for abandoned mines) then significant reduction in the calculated reductions occurs.

RCE also modeled the potential for offset generation of the current inventory of closed mines. The model used is based on the yearly emission reductions that would qualify under the draft protocol to establish an economic benchmark against which to measure project economic viability. This was done through a pro forma economic analysis of a generic power generation project at a mine with various baseline emission levels assuming 50$/MWhr power sales price and 10$/tCO2e using four 400 ft deep wells to drain the mine and assuming $1.3 million/MW installed generation equipment. Figure 1 shows the results of the analysis.

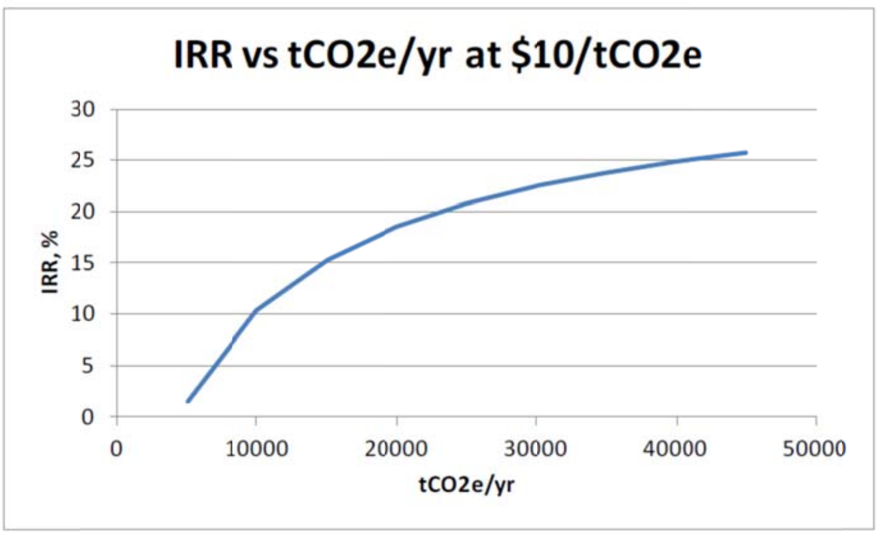

Figure 1: Return on investment versus yearly tCO2e/year baseline emission reduction
The number of potential projects relates to an acceptable return on investment. A 15% IRR would require a yearly average value of 15,000 tCO2e while a 25% IRR would require 44,000 tCO2e.

The baseline emission level of potential projects was determined by the initial rate from EPA data, the time since abandonment and the baseline decline curve with the 20% deduction. To meet a 25% IRR requirement, there are 16 potential projects with an aggregate of 1,054,000 tCO2e/year as shown in Figure 2.

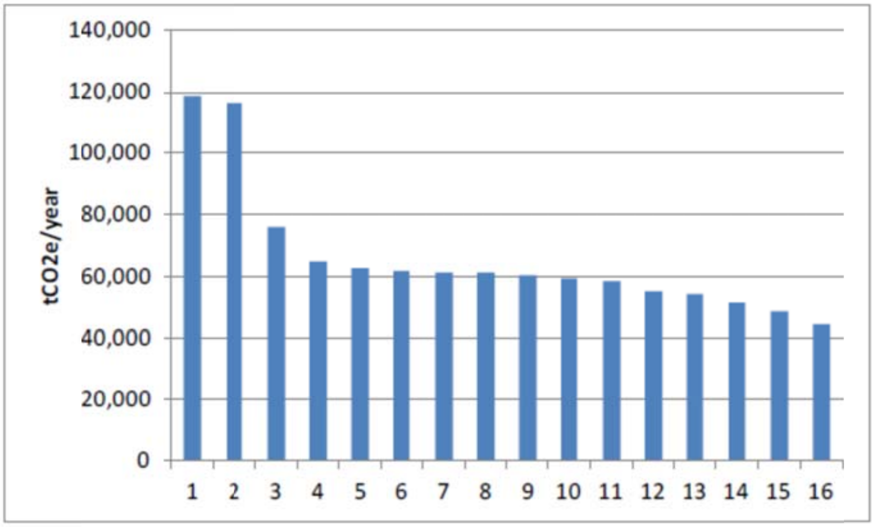

Figure 2: Potential emission reduction projects with baselines above 44,000 tCO2e/yr
To meet a 15% IRR (15,000 tCO2e/year) minimum requirement, the number of potential projects increases to 100 projects with an aggregate of 3,267,000 tCO2e/year. The actual number of potential projects is expected to be somewhat lower as risk factors such as mine void collapse and communication, low quality methane, and degree of flooding cannot be ascertained until test wells have been drilled.

Table 1: list of methane recovery projects at abandoned underground coal mines in the United States.

MSHA ID	Mine Name	Coal Company Name	Project Developer	Date of Abandonment	AMM Project Start	Continuation of Active Mine Project?
42-02028	Aberdeen	Andalex Resources Inc	Blue Tip Energy	09/25/08	2008	Yes
33-00967	Nelms #1	Harrison Mining Corp	CBM Ohio	6/10/77	1993	No
44-02134	VP No 4	Island Creek Coal Co	Consol Energy	8/9/93	1994	Yes
44-00246	VP 1	Consolidated Coal Co	Consol Energy	3/10/94	1995	Yes
44-04517	VP No 6	Consolidated Coal Co	Consol Energy	6/27/94	1995	Yes
44-01009	VP No 2	Island Creek Coal Co	Consol Energy	12/11/96	1997	Yes
46-01452	Arkwright No 1	Consolidation Coal Co	Consol Energy	5/24/96	1997	Yes
46-01455	Osage No. 3	Consolidation Coal Co.	Consol Energy	5/25/96	1997	Yes
46-01867	Blacksville No 1	Consolidated Coal Co	Consol Energy	6/10/93	1997	No
44-01520	VP No 3	Consolidated Coal Co	Consol Energy	3/10/98	1998	Yes
46-01438	Ireland	Consolidated	Consol	6/10/94	2003	No

		Coal Co	Energy			
44-03795	VP 8	Island Creek Coal Company	Consol Energy	06/26/06	2006	Yes
46-01286	Windsor Mine	Windsor Coal Company	Consol Energy	03/22/05	2007	No
11-00588	Old Ben No 21	Old Ben Coal Co	DTE Methane	11/13/95	2002	No
11-00589	Old Ben No 24	Old Ben Coal Co	DTE Methane	7/10/98	2002	No
11-00590	Old Ben No 26	Old Ben Coal Co	DTE Methane	7/10/98	2002	No
11-02392	Old Ben No 25	Old Ben Coal Co	DTE Methane	9/10/96	2007	No
N/A	5 mines	various	DTE Methane	1950-1971	2007	No
11-00599	Orient No 6	Freeman United Coal Mining Co	DTE Methane	03/13/97	2008	No
N/A	3 mines	various	Grayson Hill Farms	1950-1971	2003	No
N/A	5 mines	various	Grayson Hill Farms	1950-1971	2011	No
01-00758	Blue Creek No. 3	Jim Walter Resources Inc	Jim Walter Resources Inc	4/26/00	2000	Yes
01-01322	Blue Creek No 5 Mine	Jim Walter Resources Inc	Jim Walter Resources Inc	04/26/07	2007	Yes
46-01434	Consol No 9	Consolidation Coal Co.	small developer (name?)	9/10/78	1997	No
46-05722	Consol No. 20	Consolidation Coal Co.	small developer (name?)	10/1/82	1997	No
36-00906	Gateway Mine	Gateway Coal Company	small developer (name?)	12/9/92	1999	No
46-01482	Valley Camp 3	Valley Camp	small developer (name?)	1/10/83	2007	No
12-00323	Kings	Kings Station	small developer (Roy Farmer)	10/29/73	2001	No
05-02820	Golden Eagle	Basin Resources Inc	XTO	5/30/96	1997	No

Table 2: Emission reductions assuming project start date year 2000.

MSHA ID	**Mine Name**	**Coal Company Name**	**Project Developer**	**Voluntary Carbon Registry**	**Date of Closure**	**AMM Project Start**	**Continuation of Active Mine Project?**	**Initial Rate MMcf/d**	**Average Yearly Reduction**
01-	Blue	Jim Walter	Jim	CCX	4/26/0	2000	Yes	12.7	378,460

00758	Creek No. 3	Resources Inc	Walter Resources Inc		0				
12-00323	Kings	Kings Station	small developer (Roy Farmer)		10/29/73	2001	No	0.35	4,535
11-00588	Old Ben No 21	Old Ben Coal Co	DTE Methane	VCS	11/13/95	2002	No	1.4	30,957
11-00589	Old Ben No 24	Old Ben Coal Co	DTE Methane	VCS	7/10/98	2002	No	1.2	30,747
11-00590	Old Ben No 26	Old Ben Coal Co	DTE Methane	VCS	7/10/98	2002	No	1.6	40,996
46-01438	Ireland	Consolidated Coal Co	Consol Energy		6/10/94	2003	No	1.4	29,111
N/A	3 mines	various	Grayson Hill Farms	CCX	1950-1971	2003	No	NA	
44-03795	VP 8	Island Creek Coal Company	Consol Energy		06/26/06	2006	Yes	42.6	1,563,895
46-01286	Windsor Mine	Windsor Coal Company	Consol Energy		03/22/05	2007	No	0.49	16,717
11-02392	Old Ben No 25	Old Ben Coal Co	DTE Methane	VCS	9/10/96	2007	No	1	23,021
46-01482	Valley Camp 3	Valley Camp	small developer (name?)		1/10/83	2007	No	1	15,153
01-01322	Blue Creek No 5 Mine	Jim Walter Resources Inc	Jim Walter Resources Inc	CCX	04/26/07	2007	Yes	15.12	564,198
N/A	5 mines	various	DTE Methane	VCS	1950-1971	2007	No	NA	
11-00599	Orient No 6	Freeman United Coal Mining Co	DTE Methane	VCS	03/13/97	2008	No	1	23,643
42-02028	Aberdeen	Andalex Resources Inc	Blue Tip Energy	VCS	09/25/08	2008	Yes	2.87	107,898
11-00600	Orient #3	Freeman	DTE Methane	VCS	02/01/84	2009	No	1.5	23,231
N/A	5 mines	various	Grayson Hill Farms	CCX	1950-1971	2011	No	NA	

(RCE 3)

> **Response:** Thank you for the support and for providing further analysis of the additionality of abandoned underground mine methane recovery activities.

J-1.15. Multiple Comments: Section 3.4.2 (b)(4)(A) Performance Standard Evaluation for Abandoned Mine Methane Recovery Activities

Issue: Destruction of extracted mine methane via any end-use from abandoned mines automatically meets the performance standard evaluation.

The protocol states that pipeline injection of mine methane extracted from methane drainage systems at *active underground* mines is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol. Based on available data[200] pipeline injection of mine methane extracted from methane drainage systems at *abandoned* underground mines is occurring at a similar rate. According to 2011 data, there were 16 AMM projects that recovered gas from 38 abandoned mines; 13 of those 16 projects inject into pipeline (over 80 percent). In other words, these data suggest that pipeline injection of mine methane extracted from abandoned mines may be similarly "business as usual," as it is from underground mines. If so, this would raise similar additionality concerns. (CAR 1)

Comment: Additionality of abandoned mines: Approximately one third of all methane liberated from abandoned mines in the United States is currently captured and destroyed. MMC projects at abandoned mines continue to be implemented. Non-additional projects would generate a large portion of offsets credits from abandoned mines, unless (1) the Protocol were to effectively incentivize many more truly additional projects than participating non- additional projects, and (2) conservative methods of estimating emissions reductions from participating projects result in an under-crediting of reductions at least as large as the non- additional crediting.

> **Recommendation**: Eligibility criteria should be established for abandoned mines so that the total credits generated by abandoned mines is expected to be additional based on conservative business-as-usual scenario analysis. In particular, the Board should consider excluding abandoned mines that captured methane for use when active (not including flaring) on the basis that methane capture at such mines is common practice.

At present, around one third of all methane liberated from abandoned mines in the United States is captured and destroyed. This methane is captured and destroyed by projects at 38 abandoned coal mines.[201] This means that if all new mine methane capture at abandoned mines were eligible for crediting, as currently written in the draft

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[200] Ruby Canyon Engineering, Inc., *Abandoned Coal Mine Methane Offset Protocol Background Information on Performance Standard and Additionality* (March 2013)

[201] Ruby Canyon Engineering, Inc. (2013). *Abandoned Coal Mine Methane Offset Protocol: Background Information on Performance Standard and Additionality*. http://www.arb.ca.gov/cc/capandtrade/protocols/mmc/rceammbackground.pdf (accessed 21 Aug 2013).

MMC protocol, it is possible that a large proportion of the credits generated by abandoned mines under the Protocol will be from non-additional projects. This is especially possible due to large disparities in methane released from different abandoned mines and because mines that release the most methane are also most likely to capture methane without the offset protocol. Measures must be taken to avoid the generation of credits from non-additional projects, or even a single large non-additional project, that would make up a sizable portion of total credits generated by the protocol.

ARB staff response to this issue: Board staff has determined that methane capture at abandoned underground mines is not “common practice,” and therefore is additional. This is based on an analysis of the number of abandoned mines where methane capture occurs now (38) out of the pool of gassy mines that have been abandoned in the country since 1972 (>400).

We do not believe that this analysis sufficiently shows that large-scale over-crediting is unlikely to result from the abandoned mine portion of the Protocol. In particular, we are concerned that, under the Protocol as currently written, the number of offsets credits generated from large business-as-usual MMC projects at abandoned mines could overwhelm the number of credits generated by truly additional projects. We believe that changes need to be made to the eligibility criteria for abandoned mines to avoid crediting mines most likely to capture methane on their own after abandonment, and suggest procedures for assessing whether the abandoned mine portion of the Protocol is expected to avoid over-crediting after such exclusion. We describe the terms of this analysis below.

1. Additionality assessments should be based on the quantity of methane being captured, in addition to the number of mines capturing that methane.

The impact of the offsets program on the effectiveness and integrity of the Board’s cap-and-trade program is a matter of the quantity of offsets credits produced and the quality of those offsets in terms of the real additional reductions they represent. The atmosphere only “cares” about total emissions, and total real reductions, not if those reductions come from one mine or many.

An extreme example might be useful in explaining this point. Let’s say that the MMC protocol credits reductions from 100 abandoned mines. Let’s also say that one of these abandoned mines vents 10,000 units of methane, and the other 99 mines vent 1 unit of methane each. The outcomes of this protocol on the Board’s cap-and-trade program rest almost exclusively on what happens with the one high-emitting mine. If the high-emitting mine would have implemented an MMC capture project on its own without the protocol (the project is non- additional), then the resulting false crediting would overwhelm any emissions benefit from the 99 other MMC projects. This example should demonstrate that when sizes of projects vary, it is important to look at the effect of a protocol on emissions, not just on numbers of projects. Methane emissions from underground and abandoned mines vary by several orders of magnitude.

2. Current practice should be evaluated for subsets of mines expected to participate in the Protocol.

In the Staff Report, the Board Staff indicated that a performance standard analysis of additionality was undertaken for a subset of active underground mines (i.e., those with drainage systems). For abandoned mines, it appears that no analysis was done of similar subsets of abandoned mines (i.e. abandoned underground mines with drainage systems, or mines that had MMC projects while active). In addition to the entire population of potential projects, a robust additionality assessment under a conservative business-as-usual scenario must also examine subcategories of potential projects that are easily distinguishable in a way that is relevant to the question of additionality. We believe that this approach should be used for performance standard analyses for all future Protocols.

The Board should consider excluding mine methane capture projects installed at abandoned mines that captured methane for use (not including flaring) when active without offsets because these projects are common practice. We make this recommendation on the basis that it is common for mines which captured methane while active to also capture methane upon abandonment.[202] If a mine captured methane while active under the Board's offsets program the mine should be allowed to complete its 10-year crediting period if it closes during that period.

Certainly one potential downside to this exclusion is that allowing all mines to generate offsets when abandoned would create an additional financial incentive for mines to close. However, we understand that the Board should be primarily concerned with ensuring that the Protocol meets the requirements laid out by AB 32 that credits must be real and additional. The Board should only consider risking the generation of non-additional credits if the potential for the Protocol to incent mine closures is so large that the emissions savings from the effects of the protocol from mine closers clearly outweighs the expected non-additional crediting that would result from including these mines.

3. The majority of credits that would be generated by abandoned mines under the current draft protocol is likely to be from non-additional projects. Steps need to be taken to avoid non- additional crediting.

4. We understand that since 2000, mine methane capture projects have been installed at five abandoned mines which were not registered under a voluntary offsets program.[203] We also understand that the MMC protocol, at current offsets prices, is expected to enable on the order of five to ten additional projects to be implemented.[204] While a past rate of business-as-usual project development is only an approximate predictor of near-term future development, and the estimate of five to ten new additional projects is one individual's informed estimate, these numbers provide one possible, and

[202] Communication with industry expert.
[203] Comment submitted to the Board by Ruby Canyon Engineering on the draft MMC protocol on October 22, 2013.
[204] Estimate made by industry expert in informal conversation.

not unlikely, scenario for the outcomes of the Protocol on abandoned mines. This scenario points to a substantial portion of the abandoned mines participating in the Protocol being non-additional. If the business-as-usual projects were larger in size than the truly additional projects (likely because larger projects are more cost effective and more likely to move forward on their own), then the proportion of non-additional credits could be substantially greater than half of the credits generated.

Further, a total of seventeen MMC projects were implemented at abandoned mines since 2000 including projects which participated in a voluntary offsets protocol.[205] It is well documented that the type of additionality assessment performed by these voluntary offsets programs has been ineffective at filtering out non-additional projects. To the extent that these projects would have been implemented without the offsets income (are non-additional), the total quantity of business- as-usual methane capture would be even greater. A detailed review of MMC projects at abandoned mines participating in voluntary offsets programs should lend some insight into the additionality of these projects.

A) Methods for assessing common practice for mine methane capture at abandoned coal mines

At the August 19 Offsets Workshop we offered our understanding that, at present, around half of the methane from abandoned mines that could viably be captured, with or without carbon offsets, is already being captured. This mine methane capture is happening at 38 mines in the United States out of approximately 105 abandoned mines where methane capture is potentially viable according to an assessment by Ruby Canyon Engineering.[206]

These 38 mines with methane capture represent approximately one third of mines with an opportunity for methane capture (38 mines out of 105). While these 38 mines also represent a small fraction of the many thousands of abandoned mines in the country, this fact bears no relevance to an additionality determination for the Protocol. Assessments of BAU practice for the purpose of additionality testing should assess the potential influence of the Protocol compared to the BAU practice that could be credited under the Protocol. The Protocol will comply with the additionality requirements of AB 32 only if the total influence of the Protocol on emissions is far larger than any credited BAU practice, assuming that conservative reduction assessment methods can balance out crediting of such BAU practice.

The “denominator” used for BAU practice assessments should therefore be the pool of facilities where projects are actually feasible, rather than the pool of all abandoned mines in the country. For example, consider the inclusion of abandoned gold mines and copper mines in the denominator for assessing BAU mine methane capture from abandoned mines. Clearly these abandoned mines should not be included in this

[205] Comment submitted to the Board by Ruby Canyon Engineering on the draft MMC protocol on October 22, 2013.
[206] Ruby Canyon Engineering, Inc. (2013). *Abandoned Coal Mine Methane Offset Protocol: Background Information on Performance Standard and Additionality*. http://www.arb.ca.gov/cc/capandtrade/protocols/mmc/rce_amm_background.pdf (accessed 21 Aug 2013).

assessment because they do not release methane and therefore would not be able to participate in the Protocol even if they were included in the Protocol. Similarly, abandoned coal mines that that do not have characteristics that make them candidates for participation in the Protocol should also be excluded from the denominator. BAU assessments must evaluate current practice for the group of facilities that could potentially implement the practice in order to meaningfully assess the potential for non-additional crediting.

When assessing current practice related to mine methane capture, it is important to evaluate the proportion of methane that is being captured in addition to the proportion of mines where methane capture is already occurring. Mines with larger releases of methane are more likely to install mine methane capture technologies than mines with smaller releases. Further, from the perspective of atmospheric impacts, the total methane released, not the proportion of mines where that methane originates is the relevant consideration. For these reasons, an additionality assessment based on the quantity of methane already being captured more accurately reflects the risk of non-additional crediting than an assessment of a proportion of mines. Approximately one third of all methane from abandoned mines is being captured,[207] comprising approximately half of the methane released from the 105 abandoned mines that Ruby Canyon Engineering has identified as having the potential to feasibly implement mine methane capture.

B) Avoiding the non-additional crediting of BAU methane capture at abandoned mines
Given that a substantial proportion of feasible methane capture from abandoned mines is already occurring, it is necessary to take precautions to avoid crediting non-additional activities at abandoned mines. We believe that the Board faces similar considerations for methane emissions from abandoned mines as it does for pipeline injection of methane from drainage systems at active underground mines. We recommend that the Board perform an analysis of existing MMC projects at abandoned mines and trends in the characteristics of mines implementing such projects.

If that analysis shows that mines which capture methane when they are active are highly likely to continue capturing methane when they are abandoned, the Board should exclude this category of mine from participation in the Protocol because it will be likely that these projects will be non-additionality. In addition, if many of the 38 abandoned mines that currently capture methane were not capturing methane when they were active, the Board should examine the characteristics of these mines to determine other mine attributes have been predictive of the decision to capture methane.
In sum, while we appreciate the work that ARB staff has devoted to the development of the Protocol to date, we still believe that, due to the concerns raised above and in our previous comment letter, substantial non-additional crediting will occur under the Protocol as currently drafted. (STANFORD 2)

Comment: At the meeting each of you asked probing questions which we would like to take the time to respond to more fully than we did in person. Below we list some of the

[207] ibid

questions you asked last week, followed by considered answers which we hope may further clarify the reasons for our concerns and recommendations. These answers are described in more detail in the formal comments we are submitting on the draft Protocol, but we thought it might be helpful to provide some direct answers to the questions you raised.

Why is there such concern about the level of additionality of the abandoned mine portion of the Protocol when only a handful of abandoned mine MMC projects were implemented since 2000 without the help of carbon credits?

We understand that, since 2000, mine methane capture projects have been installed at seven abandoned mines which were not registered under a voluntary offsets program. Informally, one industry expert estimated that they expect the MMC protocol, at current offsets prices, to enable on the order of five to ten additional projects to be implemented. While a past rate of business-as-usual project development is only an approximate predictor of near-term future development, and the estimate of five to ten new additional projects is one individual's informed estimate, these numbers provide one possible, and not unlikely, scenario for the outcomes of the Protocol on abandoned mines.

This scenario points to around half of the abandoned mines participating in the Protocol being non-additional. If the business-as-usual projects capture more methane than the additional projects (likely because larger projects are more cost effective and more likely to more forward on their own), then the proportion of non-additional credits would be greater than half of all credits generated under the Protocol by abandoned mines. Excluding projects that captured methane when active would improve the balance of additional to non-additional credits; three of the business-as-usual projects that were built since 2000 injected methane into a pipeline when they were active. But excluding these projects would still allow four non-additional projects at abandoned mines to participate in the Protocol, which is still substantial compared with five to ten truly additional projects expected to participate by one industry expert.

One recommendation raised at the meeting was to exclude abandoned mines that captured methane without the help of carbon credits when they were active. But doesn't allowing these mines to be eligible create a financial incentive for mines to close, become abandoned, and generate credits.

We make the recommendation to exclude these mines from crediting on the basis that it is common practice for mines that captured methane when active to also capture methane upon abandonment.[208] Certainly, one potential downside to this exclusion is that allowing all mines to generate offsets when abandoned would create an additional financial incentive for mines to close. However, we understand that the Board must be primarily concerned with ensuring that the Protocol meets the requirements of AB 32 that credits should be real and additional. The Board should only consider risking the generation of non-additional credits if the potential for the Protocol to incent mine closures is so large that the emissions savings from the effects of the Protocol from mine

[208] Communication with industry expert.

closures clearly outweighs the expected non-additional crediting that would result from including these mines.

Finally, if the Board is assuming that the financial incentive created by offsets may induce some mines to close because they are at the margin, this assumption also supports the need for a fuller assessment of whether the incentive of offsets credits at mines that are currently active will be sufficient to induce these mines to remain open. (STANFORD 1)

Comment: And let me briefly mention three key concerns. One: By allowing all new methane capture from abandoned mines to participate in the protocol, it is possible and perhaps likely the majority of these credit from abandoned mines will be from non-additional projects that were already being built. These are projects that would be subsidizing projects that would have been built without the offsets protocol. To avoid this, the Board should exclude sub-categories of abandoned mines most likely to implement mine methane capture projects on their own. (STANFORD 3)

> **Response:** As indicated in the Staff Report, the assessment of additionality of abandoned underground mine methane recovery activities was done in accordance with the published ARB process for the review and approval of compliance offset protocols.[209] Only 30 abandoned mine methane capture projects exist, about 10 of which are continuations of pipeline injection from active mines and thus ineligible under the protocol, so there are approximately 20 protocol eligible projects at over 400 mines that have closed since 1972 which were considered "gassy" at time of closure. This is the population from which mine methane emissions are estimated for the U.S. EPA's Greenhouse Gas Inventory Report. The U.S. EPA's Coalbed Methane Outreach Program has identified this population of 400+ mines as having potential for projects and manages a database of abandoned mines as a resource for project developers for the explicit purpose of identifying potential project sites. Comments suggesting that staff evaluated the level of technology penetration from the entire population of abandoned mines are incorrect. Rather, the deployment of mine methane recovery technologies were assessed in the context of coal and trona mines that are currently emitting methane and eligible under the proposed protocol.
>
> A commenter proposes evaluating additionality based on the percentage of methane currently being recovered. ARB assesses additionality on the potential projects that can be implemented and not on the percent of greenhouse gas reductions at existing projects. This process to assess additionality is consistent with the evaluation of the four existing adopted compliance offset protocols. Regardless, staff modified section 3.4.2(b)(4) of the MMC protocol in 15-day changes to exclude pipeline injection as an eligible end-use management option

[209] California Air Resources Board (2013) California Air Resources Board's Process for the Review and Approval of Compliance Offset Protocols in Support of the Cap-and-Trade Regulation. *available at* http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf (as referenced in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 1, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf)

at abandoned underground mines that injected mine methane into a natural gas pipeline while active, an activity already deemed to be common practice and therefore ineligible for the purpose of this protocol. Upon further analysis of abandoned mine methane project data provided by Ruby Canyon Engineering, ARB concluded that continuing pipeline injection activities after abandonment is common practice and considered business-as-usual.

The intent of this change is to exclude the crediting of methane destruction that would have otherwise been sent to a pipeline in the absence of the protocol. Similar to active underground mines, this would require that all abandoned mine methane from any methane sources connected to a natural gas pipeline while active be made ineligible for offset crediting. To realize the intent of this exclusion, abandoned mine methane recovery activities at mines that injected into a natural gas pipeline must not capture and destroy mine methane from newly drilled wells as it is assumed that methane from this source would have otherwise been injected into a pipeline. This ensures that the MMC protocol is incentivizing mine methane capture that would not otherwise take place in a conservative business-as-usual scenario, therefore resulting in real, additional offset credits. While staff maintains the rigor of the technology based performance standard approach to assessing additionality, the commenter should note that existing projects that meet the revised eligibility requirements capture far less than one third of methane that would be released by abandoned underground mines.

Staff disagrees with the comment asserting that the existence of abandoned mine methane capture projects without carbon finance is evidence that the protocol will generate non-additional emission reductions. The comment states that seven abandoned mines had active projects not affiliated with carbon finance when in fact there are only five such mines. 25 of 30 abandoned mines that had projects beginning after 2000 were registered in the voluntary carbon market. The comment also quotes an unnamed industry expert who suggests that 5-10 abandoned mine methane recovery projects would be implemented as a result of the MMC protocol. Based on discussions with technical working group members, staff expects approximately 5-10 projects to emerge within just the first few years of protocol adoption, and disagree with the commenter’s stated facts and the conclusions reached therefrom.

Moreover, staff recognizes that various forms of utilization of methane that results in energy production, can, in some circumstances, be financially viable without carbon finance. This does not conflict with the Cap-and-Trade Regulation as a financial additionality test is not required. In developing the Cap-and-Trade Program, ARB instead opted to pursue the performance standard approach. This approach streamlines the calculation of project baselines and determination of the additionality of projects by using standard eligibility criteria that ensure projects are additional. By establishing the standardized criteria in the Compliance Offset Protocol, there is less subjectivity by verifiers or offset project developers as to whether a project may be additional and this supports consistent quantification rigor in the offset program.

Commenters also suggested that staff should have evaluated the additionality of pipeline injection at abandoned underground mine methane recovery activities in the same fashion as the active underground mine methane drainage activities where a subset of mines, those with drainage systems, were examined. This evaluation determined that pipeline injection was common practice at active underground mines with drainage systems. As stated in the staff report, common practice for active underground mine methane drainage activities was assessed by examining the smaller population of active underground mines with existing methane drainage systems because the installation of methane drainage systems is considered a response to regulation requiring that methane levels be kept below one percent in mine working places and intake air courses.[210] There is no such regulatory requirement for abandoned mines and thus examining subsets of abandoned mines is not warranted.

Lastly, consistent with ARB's assessment that the MMC protocol does not encourage or incent coal mining, staff believes the MMC protocol also does not incentivize the early closure of mines as suggested by one commenter. The MMC protocol does not change the primary business of mining companies. Please note that more detailed responses to the specific issues of incentivizing coal mining and additionality policy, as they relate to the proposed MMC protocol, can be found in responses to 45-day comment J-1.17 and J-1.16, respectively.

Additionality Policy

J-1.16. Multiple Comments: We recommend the Board adopt the following method for assessing additionality.

We advise the Board to conduct the following analysis to assess the expected results of the Protocol on emissions. This analysis would be performed on the pool of abandoned mines that could implement MMC projects with the help of the Protocol, not including the mines that would be excluded through the analysis described above. We understand this approach to be practical and feasible, and the best way to assess the additionality of a protocol, given the limitation that we only have the past and the present to predict the future.

We believe an additionality assessment involves assessing:

(1) The non-additional credits that are expected to be credited by the Protocol. This could involve assessing the credits that would have been generated by non-additional projects had the Protocol been adopted in the recent past.

[210] Title 30, Code of Federal Regulations, 75.323, 2006 (as cited in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 3, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf.

(2) The expected effect of the Protocol on new project implementation.
(3) Any shifts in mine abandonment trends, MMC technologies and market factors that would suggest project implementation trends would differ from the past going forward.

The Protocol would be considered to meet the additionality requirements of AB 32 if:
(1) the expected effects of the Protocol on new project development substantially exceeds the crediting of activities that would have be built on their own, and
(2) conservative methods of estimating emissions reductions is estimated to under-credit emissions reductions by at least the amount of over-crediting expected to result from non- additional projects participating in the Protocol.

We believe that this is a common sense and practical approach to testing additionality, and that it is the best way for the Board to protect the environmental integrity of its offsets program.

This additionality assessment should be supported by ex-post analyses of trends following the adoption of the Protocol.

An ex-post analysis several years after Protocol adoption should confirm the expectations on which the Protocol was adopted, or rates of project implementation should be greater than predicted indicating even greater additional crediting. If a clear indication of the effects of the Protocol on project development is not apparent, further changes should be made to the Protocol so that the Board can avoid non-additional crediting.

While additionality is a statutory requirement under AB 32 for all offsets protocols, setting conservative criteria that avoids any non-additional crediting is especially crucial for a Mine Methane Capture protocol. The particular challenges of this Protocol— including the large sizes of individual offset projects, as well the complex interactions with federal law— recommend a heightened focus on setting robust standards. We therefore support the Board in its endeavor to develop conservative eligibility criteria that avoid crediting any non-additional pipeline injection projects. An equal level of rigor and conservativeness must also be applied to all project types covered under this Protocol. (STANFORD 2)

Comment: There was large scale over-crediting unless preventative measures are taken. California's offsets program follows pretty dismal experience thus far with other offsets programs that have largely failed to deliver the reductions they claim. California has the opportunity to do this right. Doing it right requires solid analysis and conservative decisions about project eligibility which ensure the wider effects of the incentives created by the protocol are positive and the credits represent real additional emissions reductions. (STANFORD 3)

Comment: Truly conservative business as usual assumptions need to be made when setting eligibility criteria for projects at abandoned mines in order to avoid generating substantial non-additional credits. (STANFORD 4)

Comment: At the meeting each of you asked probing questions which we would like to take the time to respond to more fully than we did in person. Below we list some of the questions you asked last week, followed by considered answers which we hope may further clarify the reasons for our concerns and recommendations. These answers are described in more detail in the formal comments we are submitting on the draft Protocol, but we thought it might be helpful to provide some direct answers to the questions you raised.

Claims that the abandoned mine portion of the Protocol could generate a majority of credits from non-additional projects is irrelevant under the Board's definition of additionality.

Last Wednesday we learned that the Board defines a project type as additional if that project type is not common practice, where common practice is assessed as a proportion of facilities currently implementing the technology to the number of facilities that could possibly implement the technology.

AB 32 describes additionality thus:
38562(d)(2) For regulations pursuant to Part 5 (commencing with Section 38570), the reduction is in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur.

We believe that the Board's adopted process of assessing additionality with a common practice analysis for a population of facilities does not reflect the spirit and intention of AB 32. The fundamental idea of an offsets program is to "offset" real reductions under the cap with real reductions outside of the cap. If the abandoned mine portion of the MMC protocol generates a large proportion of its credits from projects that would have been implemented regardless of the offsets income, the Protocol does not fulfill the spirit and intention of AB 32, nor the statutory requirement it establishes.

We describe procedures by which the Board could practically assess additionality in a way that does meet the intention and requirement of AB 32 and does not require project- by-project assessments. We believe these procedures are feasible within the capacity of the Board. What is required is to use a performance standard that is simply somewhat more involved and analytical than the assessment of common practice on the basis of an ill-defined population of facilities.

An additionality assessment should involve (1) conservative estimates of the business-as- usual projects that could be credited by a protocol, based on past trends, and (2) conservative estimates of the expected effect of the protocol on new project development. (3) A project type should be considered additional if the expected effect of the protocol on emissions reductions far exceeds the expected non-additional crediting that could occur under the protocol, and if the conservativeness of the protocol's methods of estimating emissions reduced by participating projects counter-balances the anticipated non-additional crediting. Please note that this does not mean that there can be no credits generated by non-additional projects, but simply that the total number of credits generated by the Protocol should not exceed the effect of the Protocol on emissions reductions.

We encourage the Board to do this analysis on the abandoned mine portion of the MMC protocol, and to exclude subsets of abandoned mines from participation in the protocol to avoid over-crediting. (STANFORD 1)

> **Response:** As described in the Staff Report, the assessment of additionality for the MMC protocol was done in accordance with the published ARB process for the review and approval of compliance offset protocols.
>
> > The GHG emissions reduction must be additional, or beyond any reduction required through regulation or action that would have otherwise occurred in a conservative[211] business-as-usual scenario.[212] In order for ARB to ensure offset credits are additional, ARB would not adopt a protocol for a project type that includes technology or GHG abatement practices that are already widely used.[213]
>
> The document further articulates:
>
> > To assess if a specific GHG mitigation method may have "otherwise occurred," staff will establish if that method is common practice in the geographic area in which the proposed Compliance Offset Protocol is applicable. Where possible, this review would include staff's best estimate of the percent of the technology or mitigation in use for that sector.[214]
>
> The ARB offset program is designed very differently than other offset programs by relying on standardized assessments of additionality established by ARB through a multi-year public process and not relying on project-specific assessments done by the project developers themselves and then approved by validation or verification bodies. ARB develops standardized rather than project-

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211 "Conservative," in the context of offsets, means "utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements." Title 17, California Code of Regulations, section 95802(a).

212 "Business-as-usual scenario" means "the set of conditions reasonably expected to occur within the offset project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends." Title 17, California Code of Regulations, section 95802(a).

213 California Air Resources Board (2013) California Air Resources Board's Process for the Review and Approval of Compliance Offset Protocols in Support of the Cap-and-Trade Regulation. *available at* http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf (as referenced in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 1, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf).

214 Ibid.

specific approaches to assessing additionality. This process is the same for all Compliance Offset Protocols regardless of the size of the projects that are developed.

In a 2013 decision, the Superior Court of California found that ARB's "use of a standardized mechanism is supported by evidence contained in the administrative record" and that it is within ARB's "legislatively delegated lawmaking authority to choose standardized mechanisms." *Citizens Climate Lobby and Our Children's Earth Foundation v. California Air Resources Board* (San Francisco Superior Court, No. CGC-12-519554). In his decision, the judge wrote

> "All parties agree that each and every reduction must be additional. They disagree on how to determine additionality...Determining additionality is difficult, and it is impossible to precisely delineate between additional and non-additional projects. (R24-4-7.) All additionality determinations suffer from this limitation, not just standards-based approaches. Petitioners ignore this reality and insist Respondent must use a perfect additionality mechanism or none at all. This argument is inconsistent with the science behind additionality and Petitioners own statements."

Like other Compliance Offset Protocols approved by the Board in 2011, the MMC protocol utilized a performance standard approach to establish a threshold that is significantly better than average, business-as-usual greenhouse gas emissions for a specified activity. The MMC Protocol uses a technology-specific threshold, sometimes also referred to as a practice-based threshold, where it serves as the "best-practice standard" for managing mine methane. Staff assessed the level of deployment of methane recovery technologies at abandoned mines and found abatement practices to not be widely implemented within the population of facilities that could implement the technologies.

Such an approach relies upon sound analysis of data. It is worth noting that the MMC technical working group discussed the prospect of developing eligibility thresholds for active underground mines based on such attributes as mine gas flow and methane concentration and found the wide variability within a small sample size made the evaluation of subsets of mines infeasible and highly speculative. These problems are only amplified for abandoned mines. ARB staff believes the commenter's recommended approach would lack rigor due to limitations on data. One comment criticizes the process for failing to assess trends from projects in the voluntary carbon offset projects and recommends an approach to assessing additionality. Staff reviewed voluntary projects for anecdotal information but there simply are not enough abandoned mine methane projects operating to expect reliable results that can be utilized for the purpose of creating additionality standards applicable to all projects.

Staff is, as always, dedicated to ensuring the additionality of the offsets generated through Compliance Offset Protocols. In that spirit, ARB is committed to periodically reviewing Compliance Offset Protocols to ensure the continued additionality of offset credits generated. ARB will continue to monitor changes in the regulatory and technological landscapes and evaluate their impact on the MMC protocol.

Incentivizing Coal

J-1.17. Multiple Comments: Ed Moreno with Sierra Club California. As you will hear, Sierra Club shares NRDC's concerns about the coal mine methane protocol. We want to underscore two points. One is technical. We believe the protocol isn't ripe and needs additional analysis. The difference between the Stanford's researcher's analysis and the staff CARB analysis are significant enough to warrant a more careful review and consideration. For instance, there are significant differences in the assumption about how this protocol will be applied and how the coal mining industry works and will respond. (SIERRA)

Comment: And third, to add an offset protocol that will send new revenue to out-of-state coal mines with the benefit of containing allowance prices that are not in need of additional containment. (NRDC 4)

Comment: At the meeting each of you asked probing questions which we would like to take the time to respond to more fully than we did in person. Below we list some of the questions you asked last week, followed by considered answers which we hope may further clarify the reasons for our concerns and recommendations. These answers are described in more detail in the formal comments we are submitting on the draft Protocol, but we thought it might be helpful to provide some direct answers to the questions you raised.

The Board assumes that profit margins from MMC projects are 15%, but Stanford's analysis ignores the costs of MMC projects.

We wish to emphasize that our goal has been to "scope" this problem to determine whether further analysis is merited. Our original comments to the Board from July 1, 2013 estimated the potential effect on mining profits from offsets credits generated by twenty potential MMC projects at ten gassy active underground mines that the EPA has identified as having drainage wells, but where mine operators were venting (i.e., not destroying) either all or nearly all mine methane emissions in 2006.[215]

Based on your input, in the last few days we refined this analysis to include the costs of MMC projects. We estimated MMC implementation costs using the U.S. Environmental Protection Agency's (EPA's) Coal Mine Methane Project Cash Flow Model.[216] We ran the model for each sample project using mine-specific methane flows and VAM

[215] EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003

[216] http://www.epa.gov/methane/cmop/resources/cashflow_model.html accessed 20 October 2013

concentrations as reported by the EPA,[217] and mid-point values for each project cost parameter based on the range of possible inputs provided by the Model. This exercise was meant to examine whether offsets profits could be large enough to change mine owner decisions about mine operations, and whether further refined analysis is merited, even when including the cost of implementing MMC projects.

The Cash Flow Model predicts that eight mines with drainage methane flows greater than one million cubic feet per day are viable candidates for offsets flaring projects. These eight MMC offsets projects are projected to generate profit margins between 40% and 92%, with an average profit margin of 70%.

The Cash Flow Model predicts that the mines with ventilation air methane (VAM) concentrations of 0.8% or greater are viable candidates for VAM oxidation offsets projects. Profit margins for these projects range from 40% to 53%, with an average profit margin of 46%.

What about monitoring and verification costs?

In an informal conversation with a voluntary offsets verifier and consultant, the verifier estimated, based on experience with other project types, that each verification would cost $10,000 to $20,000 and that monitoring and reporting costs would be less than verification costs each year. In the revised analysis, we assume monitoring, reporting and verification costs are $60,000 for each project. To put this in context, annual profits from offsets sales of most offsets project analyzed are more than one million dollars. What are your conclusions from the refined profits analysis?

Taking into account MMC implementation costs, and the costs of monitoring and verification, and assuming a $10 offset price, we find that flaring projects can increase mining profits by an average of 12% for the eight modeled flaring projects, with a range of a 2% to a 59% increase in profits among the eight mines. We find that VAM projects can increase mining profits by an average of 5% for the four modeled VAM projects, with a range of a 4% to a 7% increase in profits among the four mines. The influence of the offsets program on mine profits would be higher if mine profit margins or MMC implementation costs are less than average, or if the offset price exceeds $10. We continue to believe that the potential profit margins of these magnitudes for some MMC offsets projects are large enough to suggest that the Board should perform a more detailed analysis to better understand the effects of these profits on the production and use of coal prior to protocol adoption.

The Board doesn't expect MMC projects to be implemented that capture methane from drainage systems at active underground coal mines, so does not include flaring projects in its profits analysis.

[217] EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003, and EPA. 2010. U.S. Underground Coal Mine Ventilation Air Methane Exhaust Characterization.

The EPA report (U.S. EPA (2013) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013- Main-Text.pdf) states:

"23 U.S. coal mines supplemented ventilation systems with degasification systems. Degasification systems are wells drilled from the surface or boreholes drilled inside the mine that remove large volumes of CH4 before, during, or after mining. In 2011, 14 coal mines collected CH4 from degasification systems and utilized this gas, thus reducing emissions to the atmosphere; all of these mines sold CH4 to the natural gas pipeline, including one that also used CH4 to fuel a thermal coal dryer. In addition, one of the mines destroyed a portion of its ventilation air methane using a thermal oxidizer" Thus, 14 of 23 mines inject drainage methane into a pipeline, a project type not eligible under the current draft Protocol. However, we understand that the *other* 9 projects that have drainage wells and vent methane rather than injecting it into a pipeline are prime candidates for MMC projects such as flaring projects. If the Board assumes that the Protocol would not credit these projects, we are interested in learning the reasons for this belief, and wonder then, why the Board includes active underground mines in the Protocol. (STANFORD 1)

Comment: Third, we understand that the income generated by offsets credits can substantially improve the profits of some participating mines. I've done an analyses of ten mines and find much larger possible impacts on mine profits than the Board staff has found, particularly at drainage wells and at the gaseous mines where the cost of implementing the mine methane capture projects are the lowest. (STANFORD 3)

> **Response**: The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore the protocol will not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study along with the 15-day changes. The study approached the issue from various perspectives, including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it will not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis was added to the administrative record of this rulemaking along with the 15-day notice, and is also available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

The assumptions and level of analysis contained within ARB's mining economics study differ from those of some commenters. In reviewing the figures provided in comments, staff found several assumptions that were flawed; not the least of which was reliance upon the U.S. EPA's Coal Mine Methane Project Cash Flow Model which contains the explicit disclaimer that "the model was NOT DESIGNED for conducting a detailed economic analysis." The analysis provided by staff included not only a microeconomic analysis at the project level but also a macroeconomic analysis of the market for coal, the primary factor influencing coal production decisions. Staff maintains that the proposed MMC protocol will not incentivize the production or burning of coal. Rather, the protocol provides an incentive to reduce the potent greenhouse gas emissions otherwise emitted during the mining process.

The comment suggesting that ARB does not expect MMC projects that capture methane from drainage systems at active underground coal mines is a mischaracterization of a conversation between the commenter and ARB staff. Staff does in fact expect such projects to be implemented.

Like other Compliance Offset Protocols approved by the Board in 2011, the MMC protocol allows for projects located throughout the United States, thereby potentially providing revenue to out-of-state entities. That does not mean that the protocol is without benefits to California. Please note that more a detailed response to the specific issue of California co-benefits, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.22. Please note that a more detailed response to the specific issue of allowance price cost containment, as it relates to the proposed MMC protocol, can be found in response to 45-day comment I-1.1.

Not Incentivizing Coal

J-1.18. Multiple Comments: The VCS supports the adoption of the Mine Methane Capture (MMC) protocol that has been developed by California Air Resources Board (ARB) staff for Board consideration. The protocol represents a significant opportunity to take immediate action to reduce GHG emissions in the mining sector which accounts for nearly 12 percent of anthropogenic methane emissions in the United States. Absent the financing available through the purchase and retirement of a carbon offset credit, there is no financial incentive to capture methane from coal mines, especially from abandoned coal mines. Adoption of the MMC protocol is therefore an important step in addressing a significant source of GHG emissions.

At the outset, we would like to comment on two concerns that were raised by those opposing the adoption of a mine methane protocol during the public consultation that occurred while the protocol was being developed by ARB staff. First, the concern that the protocol and the ability to generate carbon offset credits from mine methane capture will create perverse incentives for expanding coal mining activities is misplaced. The capital and operational costs involved in coal mining are very high relative to the revenues that could be earned from the sale of mine methane capture offsets. The impact of methane capture offset revenues on the rate of return from mining activities is negligible and will not serve as an incentive for further mining activity. (VCS)

Comment: RCE would also like to address certain areas of concern raised by other interested parties relating to the impact of MMC Project offset credit sales on the highly improbable event of making unprofitable coal mines economic, thereby arguably promoting increased coal production and associated leakage emissions.

Regarding revenues from MMC projects and their impacts on coal mines, RCE strongly believes that the Protocol as drafted will not further incentivize coal production nor make unprofitable coal mines economic. Due to the very nature of surface and abandoned mines, capturing methane from these mines would not alter coal production whatsoever. Safety concerns related to methane is not an issue at surface mines; therefore pre-draining methane from the mined coal does not influence coal production. Abandoned mines are not actively producing coal, and thus cannot impact coal production. With regards to active underground mines - methane gas can indeed limit coal mining activities, and is thus vented from the mine for safety reasons. The purpose of the Protocol is to utilize the already vented methane and would not incentivize additional methane to be vented. Additionally, it is important to note that in most cases a significant portion of the revenues from any MMC project would go to 3rd parties involved in the development and management of these projects and not the mine itself. These 3rd parties are often small companies involved in the GHG market such as GHG offset project developers, equipment vendors, and technical consultants. The idea that all revenues generated from MMC projects would go to large coal companies is false. These revenues would also support small companies whose focus is the successful development of projects that reduce GHG emissions. (RCE 1)

Comment: I also wanted to point out that most of the coal mine methane development we have ever seen is always done by small businesses. They're also energy developers, technology vendors, equipment suppliers, technology consultants, and many of these are actually based in California and provide these services to coal mines in the U.S. What we've also seen that the coal mines themselves are not the main beneficiaries of these type of projects. The fact that the two large scale ventilation air projects currently going on in the U.S. right now, Jim Alta Resources and Consol Energy, neither of those mines invested in each of those projects. They're being done solely by small business development. We also want to say we also feel like the voluntary price signal is not enough to effect any more of these ventilation air methane projects. (RCE 2)

Comment: Thank you for providing me with the opportunity to speak in support of the mine methane protocol today. I've been authorized to make these comments on behalf of [Verdeo] and Quebec's Biothermica which are also in the business of developing MMC projects.

Our companies will be responsible for the largest share of offsets that will be generated as a result of adopting this protocol. Madam Chair, I'd like to take the brief time allotted to me address an issue which has been raised in the past which may still be of concern to some members in adopting the MMC protocol. Namely, will MMC projects create unwanted subsidies for the coal industry or give a new lease of life to coal mines which should otherwise be shut down. Simply put, MMC is not the source of municipal profits for coal mine operators.

Why? For these reasons: Number one: They are coal companies, not offset project developers. They lack the necessary skills and expertise to develop these projects and have no strategic reason to build that capability. Secondly, these projects do not represent the source of material profits. Even at an extremely gassy mine, each 100 tons of coal releases enough gas for just one offset.

Under any reasonable assumptions about pricing and margins, there just isn't enough bang for the buck in the offsets of MMC project to impact the economic fortune of coal mines.

For these and other reasons, mines are not going to develop MMC projects on their own. I've spent the last several years trying to convince mine operators to allow us to develop these projects. Believe me, it's tough enough to sell when I'm offering to pay for all the cost and do all the work. There is a reason you won't find a single MMC project that's been developed to date without an offset project developer.

The task of developing these projects and delivering large offset volumes needed to contain carbon prices rests with companies like ours, entrepreneurial and willing to take a chance on our uncertain outcome. Madam Chair, we are small companies and we have more in common with Silicon Valley start-ups than with big coal. Any revenue we can generate from the sale of offsets will be used to pay for significant capital outlays such as project require and to hopefully earn a little profit for us on the costs we incur to develop and operate the projects. Some of the funds will be used to delve new materials, new skills and processes, or new equipment, which will find its way in other pollution control applications in California. Madam Chairman, members of the Board, by voting to approve the MMC project today, you'll be creating an incentive for innovation and entrepreneurship when none exists. You'll be reducing emissions from significant sources that will otherwise go unaddressed. You'll assure the supply of offsets which everybody agrees is crucial and you will most definitely not be able enabling the coal industry. (GREEN)

Comment: Eligible project activities, which involve installing devices to collect and either flare methane or use it to generate usable energy, typically have high capital costs and long payback periods, and face numerous implementation barriers.[218] The revenue they generate is generally a small fraction of the overall revenue generated

[218] See, for example, the U.S. EPA Coalbed Methane Outreach Program (2008). *Identifying Opportunities for Methane Recovery at US. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006,* available at: http://www.epa.gov/cmop/docs/profiles_2008_final.pdf. It should be noted that although this report sought to identify nominally cost-effective opportunities for methane capture and utilization at U.S. coal mines, very few of these opportunities were actually undertaken, even during historical periods of higher natural gas prices.

from a typical coal mining operation.[219] Because of these factors, offset projects are most frequently undertaken by an independent project developer specializing in the installation and operation of the required equipment. Four out of the five CMM projects currently listed or registered on the Reserve's system involve these independent operators. As a result, the coal mines themselves rarely profit directly from these kinds of projects and when they do, the net revenue they receive from the projects is quite small relative to their overall revenues.

One concern raised by some stakeholders is whether profits generated from carbon offset projects might enable coal mining companies to maintain or expand their operations, leading to "leakage" in the form of increased GHG emissions from additional coal extraction. We believe these concerns are misplaced for at least two reasons. First, as explained immediately above, project revenues going to mine operators are likely to be nominal relative to overall revenue streams. Second and more importantly, leakage would only be a risk in situations where profitable opportunities for coal extraction are going unrealized due to severe capital constraints. If a mining option does not make sense under current market conditions, then regardless of profits or cash reserves, a coal mining company will not exercise that option; it would not make sense to use extra profits to subsidize uneconomical activity. Conversely, if a cost-effective option does exist, the nominal amount of additional revenue from a carbon offset project is not likely to materially affect a company's ability to invest in its development (other sources of capital would be necessary, to which U.S. coal mining companies would have ready access even if they did not receive any offset project revenues). Our assessment, therefore, is that the risk of leakage from CMM offset projects is very low. (CAR 1)

Comment: I'll say that we have heard a number of comments about the economics and whether, in fact, this will drive additional mining. I guess the short -- my short response to that would be that if there are profitable economic opportunities for mines, mine operators today don't lack the capital or the access to capital to implement those opportunities. So any additional revenue -- and this is going to be small relative to the overall revenue for a mine -- is not going to drive them into unprofitable activities. They're already capturing those profitable ones. With that, I want to say thank you for the opportunity. We do strongly support the adoption of this protocol today. (CAR 2)

Comment: Carbon offset credits do not create an incentive for additional coal mining across the United States. Currently it is easier and cheaper to vent mine methane into the atmosphere than collect and use it for power generation or pipeline injection. As a result, methane continues to be emitted in over 24 U.S. states. Offset credits provide a very small, but important, financial incentive to encourage coal mine owners and operators to capture and utilize mine methane, which is an otherwise uneconomic and expensive endeavor. (CE2CAPITAL 1)

Comment: You'll hear criticisms today and may have heard some in the past that this protocol will lead to additional coal mining. We disagree. Coal competes in a global

[219] On average less than 1.2 percent at current California carbon offset prices - see Stanford Law School public comments on the draft Mine Methane Capture Compliance Offset Protocol, submitted July 1, 2013, Appendix C, Table 2, page C-4.

marketplace and its dominance and power generation is being eroded by the low price and abundant supplies of natural gas. The revenues from mine methane capture projects are only a small part, not a material driver, of the economics of the coal mining operation. They are, however, the critical piece that funds emissions controls. I would like to note that certain critics overstate mine economics because their analysis considers only project revenues without factoring in the substantial costs, capital included, long paid backs, and risks of developing coal mine methane capture projects. To be frank, some of the critics just don't like offsets. (CE2CAPITAL 3)

Comment: With regard to leakage, ARB, CAR, and EPA analyses[220] note that revenues from coal mining are sufficient to incentivize mine drainage, that mine ventilation is already required by U.S. regulation, and that methane recovery and destruction does not typically take place when it is not economic to do so. U.S. MMC projects can generate emission reductions without leakage and also meet ARB's criteria of being real, additional, quantifiable, permanent, verifiable, and enforceable. (PGE 1) (PGE 2)

> **Response:** Thank you for the support. With respect to comments on mine economics, please see response to 45-day comment J-1.17.
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> *It should be noted that CE2 Carbon Capital submitted two sets of identical written comments on October 15, 2013. As these written comments are duplicative, the response above serves to address both simultaneously.*

Regulatory Compliance

J-1.19. Comment: Second, we understand that some new and expanded mines should have already requested greenhouse gas PSD permits but have failed to do so. California's cap-and-trade regulation requires all offsets project developers to attest that they are in "accordance with all applicable local, regional, and national environmental and health and safety laws that apply to, the offset project location."[221] The Board should also require all MMC project operators to attest in writing specifically that the mine is in accordance with the greenhouse gas provisions of the Clean Air Act, and in particular, Prevention of Significant Deterioration (PSD) permitting requirements. This will help raise awareness among mine owners of PSD requirements, as well as help ensure that the Board does not run the risk of credit invalidation if a project is found to be out of compliance with this federal requirement after offsets credits have been generated. (STANFORD 2)

> **Response:** Staff considered the concerns raised in this comment and others similar to it and provided a detailed response in Attachment A: Response to Comments on the Environmental Assessment Prepared for the Proposed

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[220] See ARB 8/19/2013 Workshop Presentation on Discussion of Potential New Compliance Offset Protocols: http://www.arb.ca.gov/cc/capandtrade/meetings/081913/offset_workshop_presentation.pdf
See CAR Coal Mine Methane Project Protocol FAQs: http://www.climateactionreserve.org/how/protocols/coal-mine-methane/faq/
See EPA Coalbed Methane Outreach Program FAQs: http://www.epa.gov/cmop/faq/html#eight

[221] California Health and Safety Code section § 95975(c)(3)

Amendments to the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms.

J-1.20. Comment: 3.8 Regulatory Compliance: The legal compliance requirement could be a difficult standard for a mine or project developer to meet. CARB considers a facility to be in compliance if no enforcement actions occur "during the reporting period" but it is unclear how this requirement would be met in practice. In particular, the compliance requirement could be a high bar to overcome when so many different agencies (MSHA, OSHA, EPA, states, etc.) regulate coal mines. One possibility is for the MMC protocol to narrow the scope to "significant" violations. (EPA 1)

Response: The MMC protocol requires that projects meet the regulatory compliance requirements set forth in section 95973(b) of the Regulation. Pertaining to the comment, the Regulation states that a project is out of regulatory compliance if the project activities were subject to enforcement by a regulatory oversight body during the Reporting Period. As that language indicates, regulatory compliance is specific to the offset project activities, not to all activities at the mine as a whole.

Definition of Offset Project Operator (OPO)

J-1.21. Multiple Comments: In the event ARB adopts the Proposed Protocol for MMC Projects, SCI would recommend that the MMC Projects Regulatory Guidance Document, which will need to be drafted, include a clarifying definition of Offset Project Operator (OPO). Clarifying OPO definitions have been included in the Regulatory Guidance Documents accompanying the other offset compliance protocols. In the case of the MMC Projects Regulatory Compliance Guidance Document, SCI would recommend that the OPO be defined as the owner of the mine methane capture and destruction technology. Such a clarification will facilitate implementation of the MMC Projects Protocol by recognizing the OPO as the person or entity who acquired the necessary regulatory authorizations, invested in, built, and operated the MMC project to ensure the destruction of the captured mine methane. (SOLVAY 1)

Comment: In addition to our support of the adoption of the MMC Projects Protocol, Blue Source respectfully submits the following comments:

§ 3.3 (d) Offset Project Operator
As it is currently drafted, the express designation of the OPO as a Mine Operator (any owner, lessee or other person who operates, controls or supervises a coal or other mine or any independent contractor performing services or construction at such mine) may be unnecessarily limiting and problematic in administering the project. Blue Source suggests that the definition be expanded to include the scope of parties likely to be directly and critically involved in the design, financing, construction and operation of the project, namely those entities responsible for the direct operation of the destruction equipment and/or the owners of the physical assets. (BLUESOURCE 1)

Response: Thank you for the constructive suggestions. Staff recognizes that requiring a mine operator to be the OPO is overly restrictive and has revised this section of the proposed MMC protocol in 15-day changes to also allow for owners and operators of the equipment used to capture and destroy methane to be OPOs.

CA Co-benefits/Urging CA Methane Action

J-1.22. Multiple Comments: I urge you to postpone indefinitely the adoption of the Protocol scheduled for the October 24-25 Board meeting until a comprehensive plan for methane emissions reduction in California has been developed and adopted by the Board.

I am also concerned that the proposed MMC offset for active mines provides no direct benefits to Californians. AB 32 specifically instructs the Board to maximize environmental co-benefits for California, but since neither coal nor trona is mined in California, there can be no in-state co-benefits from the proposed offsets.

The draft AB 32 scoping plan recognizes that there is an urgent and scientifically sound reason for ARB to devote resources to a comprehensive plan to reducing emissions from short-lived greenhouse gas pollutants, especially methane. It makes little sense to expand the use of coal offsets when CARB hasn't taken the first steps to identify and adopt emission control measures to reduce methane emissions from fossil fuels in California.

Moreover, the most recent scientific evidence strongly argues for reducing California methane emissions to reduce the threat of public health and violations of state and federal ambient air quality standards for ozone. Whatever the merits of the proposed MMC protocol, its consideration is taking valuable time and staff resources away from the urgent need to get to work measuring methane and adopting emission control measures as quickly as practicable.

We therefore respectfully ask you to withdraw the MMC protocol from the Board's October agenda, and direct staff to immediately begin work on a measurement and emission reduction strategy for methane, and other short lived greenhouse gas pollutants. There is much to accomplish, and we look forward to working with you as we refocus and redouble our efforts to reduce the threat of global warming and protect public health from air pollution. (SKINNER)

Comment: I'm John White with the Center for Energy Efficiency and Renewable Technology. We are here today to express our strong opposition to the mine methane protocol. I want to leave to others the discussion about subsidies and details for the coal industry and the practical aspects of the protocol, because my plea to you is to consider this is the cart before the horse. And we have other work that's more important that needs to be done with respect to getting a handle on methane. One of the disappointments that we have with the implementation of AB 32 has been the failure until very recently to get to work on short-lived pollutants, particularly methane. This is a complicated subject. It's also reflective of updated science. Methane is a pollutant. It's an air pollutant that causes ozone. It should be regulated and treated as such, starting with California but also EPA.

We think that there are available technologies. But more importantly, in terms of leadership and in terms of sending the right signals to the market, we think that this Board should step back from this protocol until it has developed a comprehensive framework for the control, the measurement, and the reduction in addition of methane in California.

We think that the context of that comprehensive plan, which we believe is within sight. We're pleased, as we said yesterday, that it is on the agenda for consideration. But we think that all the support for this mine methane protocol should be deferred until that day when we have a complete plan for the measurement and the regulation and the reduction of emissions of methane. And to send a signal to EPA that it's long past time they eliminated the exemption from methane as an air pollutant. This originated because in the early days of air pollution science, it was thought that methane was non-reactive with respect to the formation of ozone. We now know based on the most recent evidence that is not the case. It causes ozone for slowly. It's less reactive, but still reactive and causes rural ozone, in some cases, significant amounts. So we think it's time to reboot and readjust our planning and our regulatory strategy to focus on methane as an air pollutant and a very powerful global warming agent, and then consider this protocol once we've done that work. (CEERT)

> **Response:** The comments about developing a comprehensive plan for reducing methane emissions in California are outside of the scope of this rulemaking and therefore no response is required. However, these comments are consistent with staff's recommendations in the proposed AB 32 Scoping Plan Update for addressing Short-Lived Climate Pollutants. Staff does not agree that the MMC protocol should be deferred while progress is made on that front. It should be noted that ARB has already adopted a compliance offset protocol for livestock projects to capture and destroy methane emissions from dairies. ARB is also working to develop a Rice Cultivation offset protocol to reduce methane emissions from rice farming. ARB also included methane in the low carbon fuel standard and promulgated the Landfill Methane Control Measure in 2009 and is expected to propose an oil and gas production, processing and storage regulation later this year.
>
> Moreover, no action that ARB takes in execution of California's Cap-and-Trade Program precludes federal action on greenhouse gas emissions. In addition, the Regulation does not obviate any existing local or regional air quality regulations or control programs related to the management of toxic air pollutants in California.

Given that California does not have any active mines, and only has abandoned mines that could potentially support MMC projects, staff recognizes that the bulk of MMC projects are likely to be developed outside of California. Nonetheless, staff disagrees with the comment that adoption of the MMC protocol would not result in in-state co-benefits. For instance, California is home to companies involved in the development of both technologies and carbon offset projects aimed at capturing and destroying mine methane as well as carbon offset traders, all California-based businesses that would benefit from the adoption of the proposed protocol. Moreover, including another Compliance Offset Protocol provides cost containment benefits to entities covered by the Cap-and-Trade Program. Please note that a more detailed response to the specific issue of allowance price cost containment, as it relates to the proposed MMC protocol, can be found in response to 45-day comment I-1.1.

Early Action

J-1.23. Comment: We recommend that ARB 1. correct the incorrect and incomplete references to the approved VCS methodologies VMR0001 and VMR0002 in Section 95990 of the amended regulation. The VCS welcomes the fact that two VCS-approved methodologies have been recognized for early action crediting in the proposed amendments. However, the references to the VCS- approved methodologies in the regulation are inaccurate with regard to one methodology and incomplete with regard to the other.

Recommendation: In Section 95990(c)(5)(F) and Section 95990(i)(1)(F) ARB, please clarify that there are two separate VCS-approved (and numbered) methodologies against which early action credits can be issued. These are: (1) *VMR0001 Revisions to ACM0008 to Include Pre-drainage Methane from Active Open Cast Mines Methodology v1.0;* and (2) *VMR0002 Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology v1.0.* The current draft language incorrectly identifies the first methodology as "VRM0001" and does not include the VCS-assigned methodology number for the second methodology: VMR0002.

2. Allow crediting for net emission reductions by early action projects that include displacement of emissions from fossil fuel consumption.

The VCS urges ARB to reconsider the proposed provision (Section 95900(i)(1)(F)(2) that effectively excludes all emission reductions from early action projects that include the displacement of CO_2 emissions from fossil fuel consumption as a result of the productive use of the captured methane. Under the VCS methodologies VMR0001 and VMR0002, project proponents can claim emission reductions from both the destruction of methane and the displacement of fossil fuels in cases where the captured methane is sued to produce power, heat or supply (natural) gas to the grid. Where emissions from the production of power, heat or supply to the gas grid are included in the project activity, they are calculated as a separate contribution to the total baseline emissions and can be separately accounted for in the project's monitoring report. These baseline emissions are referred to in the VCS methodologies as BE_{use}, and can be readily deducted from the total project emission reductions for a given reporting period.

> **Recommendation:** Revise Section 95990(i)(1)(F) as follows (additions in ***bold italics***/deletions in ~~strikethrough~~):
>
> (F) ARB offset credits will be issued for early action offset projects generated under Verified Carbon Standard ~~VRM0001~~ ***VMR0001*** Revisions to ACM0008 to Include Pre-drainage of Methane from an Active Open Cast Mine as a Methane Emission Reduction Activity Methodology, v1.0 or ***VMR0002*** Revisions to ACM008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology, v1.0 according to the following:
>
> 1. One ARB offset credit will be issued for one early action offset credit for each early action reporting period that did not include emissions from the production of power, heat or supply to gas grid replaced by the project activity in the baseline (identified as $BE_{Use,y}$ n ACM008); or
> 2. ~~No ARB offset credits will be used f~~ ***F***or early action reporting periods that included emissions from the production of power, heat or supply. to ***the*** gas grid ~~replaced~~ by the project activity in the baseline (identified as $BE_{Use,y}$ in ACM0008), ***one ARB offset credit will be issued for one net early action offset credit where net early action emission reductions for the reporting period are calculated as the difference between total project emission reductions for the period and baseline emissions related to the productive use of the methane (BE***$_{Use,y}$***);***
> 3.

The changes recommended above will result in an even-playing field for all developers of coal mine methane projects eligible for early action recognition. Those developers that have accounted for the productive use of the methane can readily deduct those emission reductions. Importantly, these deductions can be done without compromising the environmental integrity of ARB's program. (VCS)

> **Response:** In response to the commenter's suggestions, ARB staff made edits to the Cap-and-Trade Regulation through the 15-day changes to fix the incorrect or incomplete references to the VCS protocols recognized for early action crediting in the sections identified by the commenter. The Cap-and-Trade Regulation does not allow for the crediting of emission reductions resulting from the displacement of fossil fuels. However, ARB agrees with the commenter that ARB offset credits could be issued for projects developed under the two recognized VCS standards that exclude emissions from the production of power, heat or supply to gas grid replaced by the project activity in the baseline. Staff made edits through the 15-day changes to section 95990(i)(1)(F)(2) of the Cap-and-Trade Regulation that would allow a project that previously included

emission reductions from the displacement of fossil fuels ($BE_{Use,y}$) in the baseline to resubmit revised data to an Early Action Offset Program that does not include those emissions in the baseline. Upon that revised data being verified and previously issued credits being cancelled by the Early Action Offset Program; those reductions would be eligible for early action offset credits.

Eligible Destruction Devices

J-1.24. Comment: Sections 2.2(d). 2.2(e). 2.3(d) and 2.4 (f)- Project Expansion vs. New Project.

Issue: Lack of clarity on eligibility of destruction devices.
These four sections describe under what circumstances an Offset Project Operator may choose to classify certain activities as either an offset project expansion or a new project. While those circumstances are clear, what is not clear is if the "existing destruction device" referenced in each section needs to be a qualifying destruction device. We assume it does, but for clarity, it would be helpful to revise the language in each section to state "an existing qualifying or new destruction device."

As a follow up to this suggestion, it is our interpretation that an active surface mine or abandoned underground mine currently sending drained methane to a pipeline could not connect a newly drilled well to that existing pipeline (i.e. destruction device) as an eligible activity. Furthermore, it is also our interpretation that extending or somehow modifying the existing pipeline would not make it eligible as a new qualifying device. In other words, we believe it is the protocol's intent that no active surface or abandoned underground mine that has sent methane to a pipeline (or other destruction device) operating at the mine prior to project commencement will be eligible for crediting for any methane sent into that pipeline or other destruction device at any point in the future. It may be helpful to add some additional language to clarify this. (CAR 1)

Response: Thank you for the constructive suggestions. In response to the comments, staff modified the language through 15-day changes in the sections identified by the commenter to clarify that a ventilation shaft, well, or borehole must be connected to a qualifying destruction device to be considered a project expansion or a new project.

The commenter's interpretation of pipeline eligibility at active surface mines or abandoned underground mines is correct; if pipeline injection was taking place prior to offset project commencement, the pipeline is considered a non-qualifying device for the purpose of the project. This is also applicable to other destruction devices operable prior to offset project commencement with the exception for abandoned mine methane recovery activities added to section 2.4(b) which allows an abandoned mine that was previously engaged in active underground methane drainage activities to continue to use a destruction device that was considered a qualifying destruction device for those activities. This exception does not apply to pipeline injection since a pipeline is not considered a qualifying destruction device for active underground methane drainage activities and all mine gas sent to a natural gas pipeline would be ineligible for offset crediting.

J-1.25. Comment: I am just trying to understand exactly what is meant by the following:

1. Qualifying device must not be operating at the mine prior to offset project commencement - So, for example, a mine had a 5-MW CMM power project using gas drainage at the mine beginning in 2003. The project stopped in 2004. Then in 2010 the project restarted, at the same capacity with the same gensets or even a new power plant. The project would not meet eligibility requirements under the MMC Protocol. Is this a correct interpretation? Say the new project was 13 MW. Would the incremental capacity of 8 MW over the original 5 MW be eligible?

2. Gas from Ventilation shafts, wells and boreholes connected to non-qualifying devices prior to project commencement is not an eligible source. - I assume the objective here is to avoid situations where a project developer/operator replaces the non-qualifying device with a qualifying device solely to take advantage of the additional revenue from CCOs, thus not providing any real and additional emission reductions. This standard would prohibit a project operator from replacing a non-qualifying device such as gas pipeline injection with a qualifying device such as a power station, flare, etc. even if there was a period in between removal of the non-qualifying device and installation of the qualifying device. Is this a correct interpretation? (ARI)

> **Response:** If a destruction device was operating prior to the start of the project, at any capacity, it would be considered a non-qualifying device and therefore not eligible for crediting. The MMC protocol makes ventilation shafts, wells, and boreholes that were connected to a non-qualifying destruction device during the year prior to offset project commencement ineligible. If, however, the source was disconnected from a non-qualifying destruction device more than a year prior to project commencement it would again be an eligible methane source.

J-1.26. Comment: Additionality: The original CAR determination that gas pipeline injection at active UG mines is business as usual was based on a lack of available robust data. Once the GHG Reporting Program Subpart FF has collected and analyzed several years of mine and well-specific data, it may be worth reexamining the performance standard evaluation requirements for this end-use. (EPA 1)

> **Response:** Thank you for the comment and contribution to the development of the MMC protocol. Staff looks forward to having the opportunity to review that data as part of the assessment the additionality of end-use management options on an ongoing basis.

Instrument QA/QC Requirements

J-1.27. Comment: In addition to our support of the adoption of the MMC Projects Protocol, Blue Source respectfully submits the following comments:

§ 6.2 (a) (1) Instrument QA/QC
While Blue Source understands and appreciates the motive for requesting "quarterly cleaning & inspections" to ensure valid and accurate recording of data, the simple inclusion of "cleaning" has proven to be overly cumbersome and in some cases impossible in practice in the field for existing offset projects. This is primarily due to equipment design and various requirements of equipment manufactures. Many manufacturers warn that removal of the equipment for cleaning could cause inaccurate or improper readings, and in some cases the warranties for the devices are voided in the event of their removal. This is a challenge that has been encountered on a number of methane abatement projects. Therefore, it is recommended that the word "cleaning" be struck from the language entirely, as relying on a quarterly inspection alone meets ARB's requirement to ensure that the equipment is operating properly. (BLUESOURCE 1)

> **Response:** Thank you for the feedback. Staff made changes to section 6.2 of the MMC protocol through 15-day changes that removed the requirement for "cleaning" of instruments on a quarterly basis. The protocol now requires instruments and equipment used to monitor the destruction of mine methane or temperature and pressure to be inspected and maintained on a quarterly basis.

J-1.28. Comment: INSTRUMENT QA/QC

Accuracy: The 5% accuracy requirement is applicable to checks performed on the monitoring instruments, on an annual basis at a minimum. As detailed in the Protocol's Definitions section, accuracy is tested by comparing the value measured by the instrument to a reference value.

In the case of VAM projects, it is necessary to specify an allowable methane concentration for the reference gas used to perform the checks. We recommend that the Protocol include the following language, which is consistent with rigorous monitoring practices: "For VAM activities, the methane concentration of the reference gas used to check methane analyzers must be below or equal to 2% methane".
Calibrations: As certain instruments cannot be calibrated, such as thermocouples and orifice plates, it is important that the Protocol specify that calibration be required only if the manufacturer specifies a certain calibration schedule.

In any case, should a check reveal accuracy beyond the 5% threshold, the offset project operator will be required to proceed with corrective action, such as a calibration, if appropriate.

Two-month time frame: We suggested some clarifications relative to the two-month time frame, which applies to:

- The maximum time between the last check of a reporting period and the end of the reporting period
- The maximum time during which post-check data can be included in the emission reduction scaling procedure

- The time limit for applying corrective action following an unsuccessful check (MERCURY)

  Response: Thank you for the feedback. Staff made several changes in the 15-day revisions to section 6.2 of the MMC protocol to address the concerns expressed above. The final text includes language that clarifies that for active underground VAM activities, the methane concentration of the reference gas used to check methane analyzers must be below or equal to 2% methane; exempts instruments from calibration requirements if the original equipment manufacturer's specifications state that no calibration is required; and clarifies that the last instrument accuracy check of the reporting period must occur no more than two months before and one day after the end date of the reporting period.

  ARB staff also made edits to the MMC protocol to clarify procedures if a check on a piece of equipment reveals it to be beyond the +/-5% accuracy threshold. Specific to the comment, there is no time limit for taking corrective action following an unsuccessful check or on including scaled emission reductions after an unsuccessful check. Because of the conservative nature of the data scaling procedures, it is in the offset project operator's interest to take such action promptly.

Listing Information and Documentation Requirements

J-1.29. Comment: INFORMATION REQUIRED: LISTING AND VERIFICATION PHASES

Preservation of confidentiality

We wish to thank ARB for acknowledging the fact that mine owners will not be able to authorize the publication of confidential information during the listing process. As mentioned previously, mine maps and plans are part of such confidential information. We therefore recommend that only public documentation, namely readily accessible on the Internet to the public, be required at the listing phase. In addition however, the review of certain documents by the Verifier, on a private basis, may be an option for the Verification phase.

Listing phase: project diagram

With regard to the listing phase, it is our opinion that it is however reasonable to require a Project diagram which is specific to the project and includes: project coordinates, the location, quantity and types of boreholes, ventilation shafts, qualifying destruction devices and non-qualifying devices within the project's boundary. This Project diagram would replace the current "bird's-eye view map of the mine" required in article (39), and focus on the project. Detailed information regarding the equipment, as currently

required in articles 39. J&K (manufacturer, serial number…) should not be public information and thereby shifted to the verification phase documentation.
Verification phase

In order to ascertain the source of the methane being captured and destroyed by the Project, we recommend that during the Verification phase, the Verifier review mine ventilation documents provided by the mine owner/operator evidencing the source of the VAM, including but not limited:

- Mine map
- Ventilation plan
- Geological maps
-

The mine plan being a highly confidential document, we recommend excluding it from both the listing phase and the verification phase.
Surface owners

The Protocol currently requires that the name and mailing address of the surface owner be made public during the listing process. This may be problematic should the owner be a private individual. The site lease could however be reviewed by the Verifier during the Verification phase.

Document Retention

Mine maps and ventilation plan are documents under the responsibility of the coal mine, which may be a different entity than the offset project operator. As these are documents that belong specifically to the mine, it is our opinion that they should not be mentioned as documents to be retained by the offset project operator, which owns the methane destruction equipment, but is not necessarily the mine owner or operator. (MERCURY)

> **Response:** Understanding the confidential nature of some mine operation documentation, ARB staff made changes during the 15-day amendments to section 7.1 of the MMC protocol that removed the requirements for Offset Project Operators or Authorized Project Designees to submit a mine plan, mine ventilation plan, and mine maps at the time of project listing. Per the suggestion of the commenter, edits were also made to section 6.3 to remove the requirement that these documents be retained by the Offset Project Operator or Authorized Project Designee. In addition to these modifications, staff added new language to section 8 of the MMC protocol requiring Offset Project Operators or Authorized Project Designees to produce these documents at the request of the offset project verifier during project verification.
>
> In addition, modifications were made to section 7.1 to scale down the requirements for the map to be provided at listing. New language was added so that information relevant to determining methane source and destruction device eligibility that was stripped from the map requirements would be collected in activity specific project diagrams.

ARB staff considered the suggestion to remove the requirement to provide information on the surface owner(s) if different from the mine owner, but determined that the name of the surface owner may prove important for assessing the Offset Project Operator's legal authority to implement the offset project. Based on privacy concerns raised by the commenter, the requirement that the address of the surface owner be provided was removed from section 7.1.

General

J-1.30. Comment: Is devising a protocol for offsets that will keep coal mines open really what California legislators had in mind when they passed AB 32? Is this of the best or right way at the moment to reduce overall greenhouse gases? We don't believe it is. And therefore, on behalf of the Sierra Club, I respectfully ask that you reject the protocol as designed. (SIERRA)

Response: ARB staff disagrees that the MMC protocol would extend the life of a coal mine. In response to Board Resolution 13-44, and as part of the 15-day amendments, staff released the Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. The analysis is available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

Staff believes that the MMC protocol represents the best way to reduce overall greenhouse gas emissions stemming from mines at this time. The proposed MMC protocol quantifies the destruction of fugitive emissions of methane, a short-lived, high global warming potential gas that warms the atmosphere more than 20 times as much as carbon dioxide. Moreover, emission reductions resulting from the MMC protocol represents the largest source of domestic offsets for which there is a rigorous quantification methodology. The limited use of offsets allowed by the Cap-and-Trade Program serves as an important cost-containment feature in the Program, which reduces emissions and works in conjunction with other AB 32 measures that shift California's energy consumption toward renewable sources.

J-1.31. Comment: REQUIREMENTS ON LABORATORIES

The latest version of the Protocol has inconsistent requirements for laboratories that analyze mine gas.

On page 85, the accreditation requirement for labs that analyze mine gas for monitoring purposes allows the use of labs that are “certified by an accreditation body conformant with ISO 17025”. We support this language because there are very few (we identified only two) ISO accredited laboratories in the U.S.

On pages 41 and 67 however, the accreditation requirement for labs that analyze mine gas for atmospheric gas to demonstrate mining through remains ISO 17025. We do not support this language because there are very few ISO accredited laboratories in the U.S. Additionally, the testing for atmospheric gases is a relatively simple procedure that does not require an ISO certification to ensure accurate and reliable results.

We therefore recommend allowing accreditation conformant with ISO 17025 for all laboratory analyses specified in the protocol. We would also suggest providing examples of acceptable accreditation bodies such as the American Industrial Hygiene Association (AIHA), the American Association for Laboratory Accreditation (A2LA) and the National Environmental Laboratory Accreditation Program. (NELAP) (MERCURY)

> **Response:** In response to the commenter’s suggestions, staff made changes through the 15-day revisions to allow for the gas analysis to be completed by an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025 to perform test methods appropriate for atmospheric gas content analysis.

J-1.32. Comment: Miscellaneous

- There are references throughout the protocol to performing tasks "on an annual basis." Based on proposed changes to the regulation, it appears that ARB is moving away from the use of "annual" towards a "12-month period," which we support. We have found in our program that "annual" can be interpreted as a calendar year, which we do not believe is the intent of the protocol requirements.
- Equation 5.15 (p.46): in the section of this equation that details how $MM_{B,i}$ is calculated, there appear to be a number of unnecessary variables related to surface mines that should be deleted, namely $ECW_{B,i}$, $AWR_{B,i}$, and $CDW_{B,i}$. Furthermore, the variable $PGW_{B,i}$ has been left out of the equation.
- Equation 5.43: there appears to be an error in the equation; the variable $MD_{B,i}$ appears twice, while the variable $MD_{B,i}$; is missing.
- Section 6.7(f): there is a repeated phrase in the text- it currently states "Offset Project Operators ...must *adhere to* the following:" (CAR 1)

> **Response:** In response to the comments, staff modified the requirements through 15-day revisions to correct the inconsistencies.

J-1.33. Comment: In addition to the issues detailed in the appendices to this letter, we believe that the Board should consider other potentially important legal and technical issues in future discussions. For example, we note that Colorado Senate Bill 252,[222] signed into law by Colorado Governor John Hickenlooper earlier this month, makes the capture and destruction of coal mine methane from active and inactive underground mines in Colorado eligible for consideration as a form of renewable energy under that State's Renewable Energy Standard. It is our understanding that under the additionality requirements of AB 32, the inclusion of mine methane capture in Colorado's renewable energy standard should preclude all Colorado-based mine methane projects from qualifying for compliance-grade offsets in California's market. Although the most obvious additionality problem arises with electricity projects that qualify under Colorado's renewable energy standard, the problem is significantly broader. Eligibility restrictions must apply to all project types because of the increased likelihood that drainage methane would be put to use in Colorado in the absence of a California offset protocol, and therefore its capture and use is even less likely to be additional. Further, if the Protocol were to allow for other project types to be credited (i.e., flaring, pipeline injection) but not electricity generation, California's offsets program could cause methane to be flared that otherwise would have been put to productive use generating electricity. This would happen if the profits generated from selling offsets from flaring exceeds the profits that would be generated by producing electricity without offsets revenues. This effect is discussed in detail in Appendix A with regard to pipeline injection. In order to avoid any ambiguity, we urge the Board to explicitly consider the implications of including mine methane under state-level renewable energy standards or renewable portfolio standards on the additionality of mine methane capture projects in such states. (STANFORD 2)

> **Response:** ARB staff disagrees with the commenter that this change in Colorado's renewable energy standard calls into the question the additionality of Colorado-based MMC projects. Making coal mine methane an eligible energy resource for meeting the renewable energy standard, thereby potentially incentivizing the capture of mine methane, is not the same as requiring its capture. Projects in Colorado and elsewhere that utilize captured mine methane to produce electricity meet the additionality requirements of AB 32. Given that the proposed protocol includes electricity generation as an eligible end-use management option, there is no concern that the MMC protocol would incentivize flaring over this productive and additional use.
>
> Please note that a more detailed response to the specific issue of the perceived perverse incentive to flare methane, as it relates to the proposed MMC protocol, can be found in response to 45-day comment J-1.8.

[222] The bill's title is "An Act Concerning Measures to Increase Colorado's Renewable Energy Standard so as to Encourage the Deployment of Methane Capture Technologies"

K. SUPPORT FOR CAP-AND-TRADE AMENDMENTS

General Support for Amendments

K-1. Multiple Comments: Morgan Stanley Capital Group Inc. (MSCG) has reviewed the proposed amendments to the Cap-and Trade Regulation. Overall, we view the proposed changes as positive and meritorious, and recommend Board approval. We wish to commend Staff for being responsive to stakeholder input and making improvements in these Proposed Amendments that address stakeholder concerns. In particular, we believe that the Proposed Amendments do an exemplary job of resolving the important issue of defining what is and isn't "Resource Shuffling". We further commend the decision to eliminate the related affidavit requirement, and anticipate that the guidance provided will enable the electricity industry to conduct its business on an ongoing basis with confidence as regards what is and is not a violation of the Resource Shuffling prohibition.

A second main area where we believe important improvements were made is with regard to better defining what constitutes a transaction "on behalf of" another entity. In particular, we appreciate the clarification that entering into a contract for future delivery is not to be considered an "on behalf of" action.
Third, we support the changes that expand and broaden the reporting forms for allowance transactions. We regard this as a significant improvement that is necessary to fix a major "square peg in a round hole" problem that exists under the current format (MS).

Comment: By way of introduction to this letter, EDF supports the majority of regulatory amendments proposed by CARB, including, updating allowance allocation for new sectors, new CITSS functionality, revising cost containment and "legacy contracts", and the new section for natural gas suppliers. We furthermore support the continued commitment to include transportation fuels in the cap-and-trade regulation –a critical part of the overall program success (EDF 1).

Comment: All three of our organizations have been strong supporters of AB 32 since its passage. California has shown time and again that a healthy environment and strong, job-creating economy work hand in hand, and we see the same opportunity in AB 32, which has already helped position California as a leader in clean energy. We also share the goals of the cap-and-trade program to attract investment and drive innovation in achieving emission reductions at the least cost. We want to see companies investing more in California, keeping production and jobs in-state, and creating new jobs by upgrading their facilities in response to the market signal created by the program
We thank ARB staff for their commitment to developing the cap-and-trade program in an open and public process and look forward to continuing to work together to ensure AB 32 is implemented in a manner that achieves the state's emission reduction goals, maintains high quality jobs in California, and creates new jobs across the clean energy economy (NRDC 1).

Comment: We appreciate staff's careful attention to the ongoing design and development of the cap-and- trade program. The success of the cap-and-trade program is integral to the success of AB 32 and California's ability to model strong and effective climate action. AB 32 requires ARB to balance a diverse set of policy objectives in the design of the cap-and-trade program, including rewarding early action, minimizing leakage, maximizing co-benefits, and promoting equity. We commend ARB for its attention to these critical objectives to date, and ask that the Board approach future modifications to the program with the same set of considerations in mind. We appreciate ARB's ongoing commitment to examine and resolve key design features of the cap-and-trade program through an open and public process. (NRDC 2).

Comment: The Utilities appreciate both the opportunity to file comments on the proposed amendments, as well as the transparent and constructive process managed by ARB leadership and staff. The Utilities support the addition of Section 95893 which relates to the allocation of allowances to natural gas suppliers on behalf of their customers. The proposal provides a fair allocation to natural gas suppliers, on behalf of their customers, with a balanced approach to the consignment of allocated allowances. In addition, the Utilities support the proposal to use 2011 as the baseline year for the initial allocation of allowances. We appreciate ARB staffs effort to address our concerns through its recommended change to the baseline year. The utilities also strongly support the Air Resources Board's efforts to develop new offset protocols to increase offset supply and provide cost containment benefits.

Thank you for the opportunity to comment on the proposed rule regarding allowance allocation to natural gas suppliers and the general provisions for direction allocation. The Utilities appreciate ARB's collaborative and transparent approach. Generally, the Utilities support the proposed new rules (PGE 1).

Comment: CPEM greatly appreciates the time and effort of ARB and its staff in the ongoing efforts to update the Cap and Trade Regulations to ensure a successful program, with a robust and fair market and regulatory certainty for participants (CPM 1).

Comment: As an initial matter, SDG&E and SoCalGas support the following in the Proposed Regulation:

- The addition of a section on Natural Gas Suppliers, providing an allocation of allowances to natural gas suppliers for the benefit of their customers.
- Changes to Industrial Assistance, providing a greater level of assistance while additional studies on leakage are completed.
- Changes to the electricity section to remove the requirement to submit attestations regarding resource shuffling and incorporating the guidance language to clarify the scope of resource shuffling.
- Changes to the requirements for the annual compliance obligation
- Changes to include more offset protocols (SEMPRA 2).

Comment: California Clean DG Coalition appreciates the California Air Resources Board's ongoing efforts to revise the Cap-and-Trade Regulation (CCDGCC).

Comment: The City is supportive of the document, particularly proposed regulatory changes that exempt Waste-to-Energy and natural gas suppliers from the first compliance period (LBC).

Comment: Today, my husband and I are celebrating our 17th wedding anniversary. And I tell you that because I'm in a reflective mood and how our marriage is similar to my relationship with CARB. Seven years ago, as we were negotiating the final version of AB 32, I had just given birth to my third and final child. So I always know how old these regulations are because I do remember his birthday. But like a marriage at the end of the day when we all adopted AB 32, we were feeling invincible and powerful and life was going to be perfect. And like a marriage, reality sets in and sometimes it's hard. And it's not always been easy putting together these regulations and working together. But I believe a successful marriage is based upon respect and communication and a willingness to really listen to what the other person and understand what their needs are and where they're coming from. And I think that's what we've done here. We've had bumps in the roads. We've had disagreements, but we've always had open communication. Sometimes even on weekends, probably not to either of our liking, but it happened because it needed to be done. And we've gotten to a very good place because of all of this. I'm here to say thank you.

Staff particularly on the long-term contract issue worked with us. We didn't like where they had come to originally, but really listened to us. We really listened to them and what they were trying to achieve in terms of the integrity of the program, and we think we've gotten to a very good place on that. The majority of our contracts are covered while maintaining the integrity of the program. Also, increasing the auction purchase limit was very important to us. We're very hopeful that that increase to 20 percent will occur in time for the last two auctions of this year. So I really want to thank Chair Nichols, your staff, Board Members Berg and Sperling who aren't here today, former Board Member DeeDee D'Adamo who was very helpful. Richard, Edie, Steve, Rajinder, and all the other people that they probably forced to work that I don't even know. But thank you.

And so like a good marriage, there's still some issues we have to work on. And there's some technical and legal issues we have to work on here. But because we've established this pattern of really positive communication I think we're going to make it. (CALPINE 2)

Comment: I'm with Ellis and Schneider and Harris here today on behalf of the Turlock Irrigation District. First of all, I'd like to express our appreciation on behalf of the district for the openness and willingness of staff to work with the very diverse group of stakeholders. I think both the 45-day rulemaking package, Appendix A to the Board resolution today and staff's presentation all reflect the staff's willingness and openness to work with the stakeholders (TID 2).

Comment: And first, I'd like to add my appreciation to staff's open and collaborative rulemaking approach. We really appreciate all the time and effort they've spent listening to our concerns and responding. In particular, we support and ask you to approve the new section on natural gas suppliers that provides an allocation of allowances to gas utilities on behalf of our customers. We also support changes to industrial assistance, the addition of the resource shuffling guidelines, and the new offset protocols (SCGE).

Comment: We're here today to speak to you regarding legacy contracts. This has been a longstanding issue for EIP, so we're pleased to say we appreciate the staff and Board's movement on this issue. Specifically, we support the proposal to provide relief to legacy contracts with industrial counterparties that are receiving a free allocation. This coverage is designed to provide coverage throughout the duration of the contract. We think that's appropriate. Second, we support the revised staff proposal to provide transition assistance through 2017 rather than 2014 as originally proposed. We think this is a substantial improvement to addressing contracts without reasonable cost recovery that are pre-AB 32 contracts. So we support the Board's approval of the revised staff proposal and we agree with the staff that we can address these changes through a subsequent 15-day comment period. I'd just really like to thank the Board especially over the past few months in working with us on this issue. And we really look forward to working with staff going forward (IEPA 2).

Comment: I want to begin by stating our strong support for the amendments that you have before you. The inclusion of the natural gas sector into cap and trade was I think a subject with potential but working with staff and with Board members we appreciate the help and we think we got it just right. So support the regulation (PGE 3).

Comment: We would like to offer our support for much of the publicly-vetted items contained in the 45-day proposal. They're really going ahead in the right direction, and we appreciate the work that they've done. We also include our support of other comments, those of the Western States Petroleum Association, the Coalition for Fair and Equitable Allocation, and the Blue Green Alliance (PHILLIPS 2).

Comment: In March 2012, Dallas Berkshaw, a member of the EACC, current member of EMAC, and I'm sure future member of all other panels that end in AC testified before the Senate Select Committee that ARB had developed the best designed Cap and Trade Program anywhere in the world. That was true then. It is true now. And it will be true after today (NRDC 4).

Comment: And Madam Chair, I'm sorry, but I'm just going to have to violate the stipulation for staff because many of our members are family-owned businesses. And those that aren't any more still retain that characteristic within the corporate identity. And David Allgood in working with us over the past three years has had the unenviable task of walking into the living rooms of the families and telling you cannot longer do business in the way you've been doing it and you have to change. That was tough. But over these three years, he has really obtained the trust and the respect of our corporate businesses to the point where I didn't even think he could get that far. So we are looking forward to working with you to continue to work on the benchmarks. I had to get that in. Maybe we'll name a can of beans after him. With regards to the staff proposal, we think the staff proposals reflect an increasingly deeper understanding of the impacts of this program on businesses and how hard it is for us to be able to comply in a manner that is going to be acceptable. We think these current proposals make this program much stronger, make it less costly, and make it more efficient. And in that regard, I think it also gives us a step towards making it more transportable, more attractive to other states and other countries so they may adopt it. We think it has a long way to go still. However, we're more than willing to continue to work with staff and with the ARB to try to make this program the best it can be and actually be a program that other states and other countries can adopt (CLFP 2).

Response: Thank you for the support.

Comment: We stand in support of the resolutions, particularly the ones for but for combined heat and power and legacy contracts. Those are significant to us. And I think most of us here can appreciate the California State University. We have at least three members of the Board who have matriculated through our university system. And if our numbers are right, at least one in ten of my colleagues behind me are from the system. So as taxpayers, let us all be aware that we've already spent ten million in purchasing allowances. So that we can continue to operate these plants. So we are very committed to managing our budgets, and at the same time being responsible for our environment and providing a clean, safe, and healthy environment for our students to live and work in. So we're pleased with the fact that the staff listened to us. We've learned a lot from you and hopefully that you have learned a lot from us.

Special thanks to Steve Cliff and Trish Johnson who stayed late many nights and helped us navigate through the complex application process so that we could participate in the auction process. We want to continue to do that. We want to continue to work with you. We hope we can revive some of our canceled studies that we have done for combined heat and power plants on campus, because those are contributors to relieving stress on the grid.

We know this Board is also in a larger effort coordinating with the Energy Commission and the Public Utilities Commission to solve the grid constraints as a result of closing over 8,000 megawatts of once-through cooling plants. So all of this ties directly into our environmental concerns. We appreciate again what has been done. We look forward to working with you in the future. Thank you. (CSU 2)

Response: Thank you for the support.

Continued Administration

K-2. Comment: Thus far, NCPA believes that the Program has functioned as expected, and that covered entities are acclimating to the various requirements and restrictions associated with registering with CARB and using the Compliance Instrument Tracking System Service (CITSS). Moving forward, it is important that the Program continue to be administered and operated in a manner that will allow the State to meet its GHG emission reduction goals, while ensuring that electrical distribution utilities complying with the Regulation are able to continue to provide safe, reliable, and reasonably priced electricity to California residents and businesses (NCPA 1).

Response: Thank you for the support. Staff will continue to administer the program in a manner that will allow the State to meet its GHG emissions reduction goals, while ensuring that EDUs are able to continue to provide reliable electricity to California residents and businesses. As part of continued implementation and development of the program, ARB staff will continue to provide stakeholders the opportunity to comment on any proposed amendments. This will enable stakeholder input and staff recommendations, as needed. Staff will also continue to be available for meetings, workshops and other working groups in order to allow for continued public involvement throughout implementation of the Cap-and-Trade Program.

L. OPPOSITION AGAINST CAP-AND-TRADE AMENDMENTS

L-1. Comment: But I think the problem is that instead of helping out a lot of the small companies with innovative idea to get off the ground, like the cap and trade should be doing, we are just giving a lot of money to the big companies who either own landfills or coal mines. We're just taxing the people, putting a tax on energy, and giving to multi-million dollar companies. I think this cap and trade program, if you do it effectively, should be helping out small company with the innovative ideas (LEE).

> **Response:** AB 32 requires ARB to adopt regulations which would implement measures to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions. California's overall approach to meeting the goals of AB 32 is described in the Climate Change Scoping Plan. The flexibility of the Cap-and-Trade Program, together with specific design features included in the Regulation to help contain costs, ensures that the reductions needed to meet the requirements of the Regulation are cost effective.
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> Investment in more energy efficient vehicles, buildings, and industrial processes will help reduce fuel use by 2020. These reductions will help offset potential increases in the prices of electricity, natural gas, and gasoline. Staff provided a detailed discussion of the anticipated economic impacts from the proposed amendments in Chapter V of the Staff Report. As discussed in the economic analysis, ARB has determined that representative private persons and businesses would not be affected by the proposed regulatory amendments. ARB determined that the proposal would not have a significant State-wide adverse economic impact directly affecting businesses, and would have little or no impact on the ability of California businesses to compete with businesses in other states. Thus, ARB does not expect the Regulation to eliminate existing businesses in California. Cost impacts on consumers could result from changes in energy prices. Incentive programs available to small businesses and consumers will provide access to funds for investing in energy-efficient technologies, which includes low interest loans, rebates, and credits.

M. COMMENTS UNRELATED TO THE PROPOSED AMENDMENTS

Increased Natural Gas Energy Efficiency

M-1. Comment: Is the goal of CARB to reduce Greenhouse Gas Emissions and to Reduce Air Pollution, and to continually improve California's/America's Air Quality? We are in a battle with Climate Change. What are the main items of Climate Change?

A. Global Warming
B. CO2 Emissions
C. Water Conservation

If we can control these 3 items, things will change to our and our future generations benefit. Page 8 ~ top subject comes close to being what I believe to be almost the most important item of all pages. The other items are also very important, but what will/can make the biggest impact for the state/country.

We live in a very mild/warming climate, where natural gas for building space heating is possibly reducing in need. California still uses a lot of natural gas for industrial applications. We are America's Bread Basket, and all this food needs to be processed. How much natural gas is consumed in California by commercial buildings and by industry and by the power plants? How much of that combusted energy is blown up chimneys as HOT exhaust into the atmosphere? Why is this still being allowed? Might this be affecting our Global Warming issue? The US DOE states that for every 1 million Btu's of heat energy recovered from these waste exhaust gases, and this recovered heat energy is utilized in the building or facility where it was combusted, 117 lbs. of CO2 will Not be put into the atmosphere. Can this make a difference?

In combusted natural gas there is Water, and in this Condensing Flue Gas Heat Recovery process this distilled water is being produced, and all this water is very usable. This mineral free water will have a pH of between 4 and 4.5. If the pH is reduced it can be used as pharmaceutical grade water. If the pH is increased it can be used as potable water. If it is injected into the buildings sanitary sewer lines, it will help to reduce bacteria growth. Can this again, (1 more item) make a difference towards California's/ America's battle against Climate Change?

This is the last item, but it should be first. Increased natural gas energy efficiency = Reduced utility bills =Profit. We realize that natural gas prices are low today, but our oldest unit turned 30 years old last year, and I plan to be there when it turns 50. It has no moving parts to wear out. It requires little or no electricity to operate. It requires little or no maintenance. It is self-cleaning on the flue gas side.

Sidel Systems USA Inc. is just now adding to its "tool belt" the technology of Carbon Capture Utilization. This is a very exciting new offering we will be putting into operation early next year. With this Sidel CCU technology the CO2 in combusted natural gas will be captured and transformed into other usable profit streams for those employing this technology. I am proud to live in and be a California based company. Let's together Make A Difference The World Is Waiting For! (SIDEL).

> **Response:** This comment is outside of the scope of the proposed modifications so no response is needed. However, natural gas suppliers will be covered starting in the second compliance period through the duration of the program. The suppliers will have a compliance obligation for all delivered natural gas minus any natural gas delivered to covered entities, since covered entities will already have a compliance obligation for the emissions associated with their natural gas combustion. This inclusion will require natural gas suppliers to account for emissions—primarily from residential and commercial uses and small industrial facilities. In doing so, staff expects the wholesale and retail prices of natural gas to reflect the increased GHG cost, thereby providing an incentive for efficiency and technological innovation.

Hydraulic Fracturing

M-2. Comment: ARB should evaluate the impact of fugitive methane emissions from conventional and unconventional oil and gas production (fracking) upon AB32 goals and programs. (APEN 1, GAIA)

> **Response:** This comment is outside of the scope of the proposed modifications so no response is needed. However, the Draft Scoping Plan Update[223] recommends that ARB develop a comprehensive strategy for mitigation of short-lived climate pollutants, including methane, by 2015. This will help ARB to continue to develop strategies that address methane emissions and identify important complements to ARBs efforts to reduce emissions of carbon dioxide. In addition, ARB is also working towards development of a proposed oil and gas production, processing, and storage regulation, which is in progress and expected to be ready for Board consideration later in 2014.[224]

Transportation Fuels

M-3. Comment: The transportation fuels sector should be required to purchase 100% of their allowances at auction when they come under the cap in 2015. (APEN 1, GAIA)

> **Response:** This comment is outside of the scope of the proposed amendments so no response is needed. However, Staff would like to point out that the Cap-and-Trade Regulation does not include provisions for the allocation of allowances to the transportation fuels sector.

Energy Efficiency

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[223] California Air Resources Board. "Proposed First Updated to the Climate Change Scoping Plan: Building on the Framework." Posted February 2014. Available online at: http://www.arb.ca.gov/cc/scopingplan/2013_update/draft_proposed_first_update.pdf

[224] Ibid. p. 25.

M-4. Comment: I think as you know, energy efficiency is one of the cheapest and quickest ways to achieve greenhouse gas emission reductions. And one of the best ways to achieve that energy efficiency is improving buildings with additional insulation. You heard Mr. Crane speak earlier. We endorse his comments. We are a member of NAIMA and also endorse the written comments submitted by NAIMA (MANVILLE).

> **Response:** This comment is outside of the scope of the proposed amendments so no response is needed. However, electricity is a capped sector under the program and staff believes that the emissions reductions associated with this sector will help to increase energy efficiency standards within the State.

Public Process

M-5. Comment: CPEM asks that ARB give consideration to the comments set out above as it determines appropriate modifications moving forward. To the extent that ARB declines to modify the proposed regulations to address the issues raised herein, CPEM respectfully requests that ARB articulate in full its rationale in the Final Statement of Reasons, and include detailed guidance to facilitate the market's ability to comply with the regulations (CPM 1).

> **Response:** Thank you for the comment. The Administrative Procedure Act requires that the Final Statement of Reasons for a proposed rulemaking include a summary of each objection, recommendation, and public comment made regarding the Regulation's comment period(s), along with an explanation of how the Regulation has been changed to accommodate each public objection or recommendation, or the reason for making no change.

Environmental Justice and Disadvantaged Communities

M-6. Multiple Comments: We have opposed the Cap and Trade program, and make these recommendations to ensure that it does not further harm environmental justice communities. As a member of the AB32 Environmental Justice Advisory Committee (EJAC), we deliberated these ideas for improvement to the Cap and Trade program and submit the following recommendations:

- The Plan should emphasize the importance of using CalEnviroScreen to identify fence line communities to target GHG reduction programs.
- A minimum of25%, preferably more, must be spent for the benefit of the communities most burdened by pollution and socioeconomic distress (as defined by CalEnviroScreen), with at least 10%, preferably more, to be spent directly in those communities, as required by SB 535. Investment of proceeds into community- accessible GHG reduction programs should include low-income energy efficiency, solar for low-income homes, transit operations and other low and no-carbon transportation alternatives, affordable transit oriented development and urban forestry and green infrastructure (including parks).
- ARB should lead implementing agencies in the development of rigorous and consistent metrics to measure the GHG reductions and co-benefits of GHG

reduction programs using environmental, economic and health metrics. Such measurements of program accountability should be based on sound science.

- Adequate staffing and resources should be provided to said agencies to ensure transparency and accountability regarding the investment of this special source of public monies.
- ARB should prioritize strict and ongoing evaluation of the Cap-and-Trade system, enforcement of caps and management to prevent toxic hot spots, including studying alternative carbon mechanisms to reduce GHG emissions.
- The Department of Finance, ARB, and implementing agencies should ensure that covered entities are prohibited from receiving revenues from the Greenhouse Gas Reduction Fund.
- The Adaptive Management Plan should provide for proactive solutions when unintended environmental justice impacts are discovered (APEN 1).

Comment: I also make the following recommendations, which have been deliberated with the AB32 Environmental Justice Advisory Committee (EJAC):

- The Plan should emphasize the importance of using CalEnviroScreen to identify fence line communities to target GHG reduction programs.
- A minimum of 25%, preferably more, must be spent for the benefit of the communities most burdened by pollution and socioeconomic distress (as defined by CalEnviroScreen), with at least 10%, preferably more, to be spent directly in those communities, as required by SB 535. Investment of proceeds into community- accessible GHG reduction programs should include low-income energy efficiency, solar for low-income homes, transit operations and other low and no-carbon transportation alternatives, affordable transit oriented development and urban forestry and green infrastructure (including parks).
- ARB should lead implementing agencies in the development of rigorous and consistent metrics to measure the GHG reductions and co-benefits of GHG reduction programs using environmental, economic and health metrics. Such measurements of program accountability should be based on sound science.
- Adequate staffing and resources should be provided to said agencies to ensure transparency and accountability regarding the investment of this special source of public monies.
- ARB should prioritize strict and ongoing evaluation of the Cap-and-Trade system, enforcement of caps and management to prevent toxic hot spots, including studying alternative carbon mechanisms to reduce GHG emissions.
- The Department of Finance, ARB, and implementing agencies should ensure that covered entities are prohibited from receiving revenues from the Greenhouse Gas Reduction Fund.
- The Adaptive Management Plan should provide for proactive solutions when unintended environmental justice impacts are discovered. (GAIA)

Response: ARB is committed to considering environmental justice in every program and process.

In SB 535, the Legislature stated its intent to direct resources to the State's most impacted and disadvantaged communities to provide economic and health benefits through additional emissions reductions. SB 535 directs the Secretary for Environmental Protection at the California Environmental Protection Agency to identify disadvantaged communities to facilitate the allocation of at least 25 percent of program funding to projects that benefit disadvantaged communities and at least 10 percent of funding to projects located in those communities.

Another piece of legislation, AB 1532, requires the development of a three-year investment plan for Greenhouse Gas Reduction Fund investments. The first such plan was submitted to the Legislature with the Revised Fiscal Year 2013-14 State Budget in May 2013. Many projects recommended for funding (e.g., active transportation, urban forestry, low-income energy efficiency, weatherization retrofits, solar, affordable housing, transit-oriented development, low-carbon freight, improved transit) in the first three-year investment plan could either be located in or could benefit disadvantaged communities.

The amount of funding for projects located in disadvantaged communities will vary among different programs. For example, certain types of projects naturally lend themselves to having a greater benefit to disadvantaged communities. It is likely that those projects, such as weatherization or urban forestry, will exceed the minimum requirements established in SB 535 with a high percentage of funds expended in disadvantaged communities. Overall, the percentage of funding in these areas will need to be high enough to satisfy the requirements of the implementing legislation.

It is important that agencies use consistent methods to identify investments made in and those providing benefits to disadvantaged communities. ARB, the Department of Finance, and other partner agencies will develop guidance materials for the implementation of the SB 535 requirements that agencies receiving funding must follow to ensure that goals are met and exceeded where possible. The guidance will also include a process to ensure that GHG reductions and co-benefits are calculated and reported consistently.

ARB is developing the process for monitoring, assessing, and quantifying the potential impacts and benefits of the State's climate programs, policies, and actions on California's economy, environment, and public health, particularly with respect to environmental justice communities. Staff is currently developing adaptive management processes to monitor for potential adverse impacts to localized air quality and forests that may occur as a result of Cap-and-Trade Program implementation. The suitability of all tools available, including CalEnviroScreen, are being considered in developing the adaptive management program. During 2014, ARB will continue to develop both components of the adaptive management program, including defining procedures to collect and evaluate data to monitor for any potential adverse impacts and a public process to share results and findings and receive comments and suggestions. If potential adverse impacts are found, ARB staff will recommend appropriate responses to the Board, as necessary.

N. DEFINITIONS

Electricity Importer

N-1. Comment: Currently, the ISO is in the process of modifying and extending its existing real-time energy market systems to provide EIM service to PacifiCorp and its transmission customers. The EIM will be a voluntary market for procuring imbalance energy to balance supply and demand deviations from forward energy schedules through a 15-minute market and five minute dispatch in the combined network of ISO and EIM Entities.

Because the EIM will be dispatched in the combined network of the ISO and EIM Entities, imbalance energy is expected to be imported into California at times and exported out of California at times. PacifiCorp expects the imports into California will trigger a compliance obligation under the MRR and Cap-and-Trade Program for resources participating in EIM. Accordingly, the proposed revisions to the MRR and Cap-and-Trade Program include revisions to the definition of Electricity Importer and Imported Electricity to account for energy imported into California as a result of EIM.

In general, PacifiCorp is supportive of the proposed modifications to accommodate the ISO's EIM proposal. However, PacifiCorp provides the below suggested modifications to the definitions to further increase clarity and consistency with the ISO's EIM proposal:

As proposed, the definition of Electricity Importers will be revised to include: EIM Participating Resource Scheduling Coordinators serving the EIM market whose transactions result in electricity imports into California.

> **Recommendation:** PacifiCorp proposes the following revisions: EIM Participating Resource Scheduling Coordinators <u>which</u> <u>facilitate dispatch of EIM Participating Resources which</u> serving the EIM market whose transactions result in electricity imports into California.
>
> This revision is proposed to ensure consistency with the current version of the ISO's EIM proposal, in which "EIM Participating Resource Scheduling Coordinator" and "EIM Participating Resource" are distinct terms and may be distinct entities. While an EIM Participating Resource may choose to also be the EIM Participating Resource Scheduling Coordinator for purposes of dispatching resources in the EIM, an EIM Participating Resource may also choose to engage another entity to be its Scheduling Coordinator. Also, technically the EIM Participating Resources are dispatched while the EIM Participating Resource Scheduling Coordinators facilitate that dispatch. The proposed modification clarifies these distinctions. (PACIFICORP)
>
> **Response:** ARB appreciates the comment and explanation provided, however, we decline to make the requested change as the current language is sufficient given that the EIM market design has not been finalized through FERC approval.

ARB staff believes the proposed language provides implementation flexibility for when the EIM market design is finalized.

Energy Imbalance Market

N-2. Comment: With the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM) proposal being in its infancy and design stage, many stakeholders have made comments and recommendations to CAISO with respect to revising the market design and governance structure. As the stakeholder process continues and as CAISO incorporates such changes to its proposal, PGE requests that ARB abstain from referencing anything in the regulation of the EIM market until it is fully operational. Recent comments have been made to CAISO during the stakeholder process that could cause some concerns around jurisdiction, unintended consequences, and resource leakage as it pertains to the proposed co- optimization EIM structure. It would be preferable to wait for the market to mature before incorporating it into the ARB regulations. (PGEC)

Response: The EIM market will include electricity imports to California and is expected to be operational by the time these amendments take effect. It is important for ARB to include regulatory language to ensure that these imports are captured in the Cap-and-Trade program. CAISO's EIM proposal and draft tariff language are sufficient for ARB to develop initial regulatory language around EIM imports, and could be modified in future amendments if necessary.

First Point of Receipt

N-3. Comment: The Air Resources Board (ARB) is proposing to amend the definition of "First Point of Receipt" to clarify that for Greenhouse Gas (GHG) reporting purposes, the *"First Point of Receipt" means the <u>location from which</u> a <u>Generator delivers its output to the</u> <u>transmission system (the closest POR to the generation source)</u>.*

LADWP recommends an additional clarification to the definition of "First Point of Receipt" to address cases where the generation source and the first point of receipt on the North American Electric Reliability Corporation (NERC) E-tag are located in different states. For example, a NERC E-tag may show electricity generated in Needles, California flowing to a first point of receipt located in Arizona, then flowing back into California to serve customer load. Based on the definition of Imported Electricity, energy that is generated and consumed in California is not an import. However, since the first point of receipt is the basis for aggregating and reporting unspecified imports and exports, and the first point of receipt on the E-tag is located outside of California, this energy flow looks like an import. As a result, an E-tag with the generation source and load (sink) located inside California and the first point of receipt located outside California could mistakenly be reported as an unspecified import.

Recommendation: To address this, LADWP recommends adding the following sentence to the definition of "First Point of Receipt":[225]

In cases where the generation source and the first point of receipt are not located within the same geographic jurisdiction relative to the physical boundaries of California, the first point of receipt is the location of the generating facility or unit.

This would clarify what jurisdiction should be used as the origin of the energy in cases where the generation source and the first point of receipt are located in different states.

LADWP recommends the definition of "First Point of Receipt" be modified as follows:

179) "First point of receipt" means the location from which a Generator delivers its output to the transmission system (the closest POR to the generation source) ~~generation source specified on the NERC e-Tag~~, where defined points have been established through the NERC Registry. In cases where the generation source and the first point of receipt are not located within the same geographic jurisdiction relative to the physical boundaries of California, the first point of receipt is the location of the generating facility or unit. When NERC e-*Tags are not used to document electricity deliveries, as may be the case within* a *balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC* e-*Tag.* (LADWP 1)

Response: After reviewing the stakeholder's comment, ARB staff will withdraw the proposed changes to this definition in the 15-day changes. Reverting to the definition which is currently in effect ensures consistency in reporting between 2012 and 2013 data. The specific change proposed by the commenter is somewhat specific to its own system, and ARB staff does not believe such a change is needed given that the definition will ultimately remain the same as what is currently in effect.

Imported Electricity

N-4. Multiple Comments: In section 95802(a)(179) of the Regulation, a new sentence has been added to the definition of "Imported Electricity" to exempt electricity imported by an "Independent System Operator" to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation ("NERC")

[225] Under the ISO's Proposal, EIM Entities are is defined as the balancing authority that enters into the pro forma EIM Entity Agreement to enable the EIM to occur in its balancing authority area. *See* http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx

or Western Electricity Coordinating Council.

The Regulation does not define “Independent System Operator”; the term appears to refer to the California Independent System Operator (“CAISO”). However, the relevant NERC standard, Standard EOP-002 – Capacity and Energy Emergencies, applies not just to the CAISO but more generally to balancing authorities and reliability coordinators.[2] CAISO is an important, but not the only, balancing authority in California. Other balancing authorities (including some of the SCPPA members) that are not known as “Independent System Operators” may also be required to import electricity for reliability purposes under NERC Standard EOP-002 from time to time. Therefore, the definition of “Imported Electricity” should refer to balancing authorities rather than just “Independent System Operators” in the sentence on emergency assistance. Furthermore, the term “balancing authority” is defined in section 95802(a)(29).

> **Recommendation:** To avoid inadvertently restricting the application of the first new sentence in the definition of “Imported Electricity” and to maintain consistency with existing defined terms, section 95802(a)(179) should be revised as set out below:
>
> 137) “Imported Electricity” means electricity generated outside the state of California and delivered to serve load located inside the state of California. ... Imported Electricity does not include electricity imported into California by a~~n~~ balancing authority~~Independent System Operator~~ to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council. (SCPPA 1)

Comment: ARB is proposing to add the following sentence to the definition of "Imported Electricity": Imported Electricity does not include electricity imported into California by an Independent System Operator to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Reliability Corporation or Western Electricity Coordinating Council.

It appears that "Independent System Operator" refers to the California Independent System Operator (CAISO). The Initial Statement of Reasons (ISOR) states that this amendment is necessary to exclude electricity imported into California to meet emergency assistance requirements. Although the CAISO is a large balancing authority in California, there are a number of other balancing authorities in California including the LADWP that are also subject to the emergency preparedness and operations reliability standards of the NERC and the Western Electricity Coordinating Council (WECC). (See NERC Reliability Standard EOP-002-3[226] and WECC Reliability

[226] http://www. nerc.com/files/EOP-002-3.pdf

Coordinator responsibilities in RC EOP-002).[227] The NERC standards specify that in the event of a power system emergency, neighboring balancing authorities should be contacted to provide assistance. LADWP has provided emergency assistance to the CAISO in the past, and could be required to import energy into California to provide emergency assistance to the CAISO or a neighboring balancing authority in the future. Therefore, the exclusion for electricity imported into California to obtain or provide emergency assistance under NERC or WECC emergency preparedness and operations reliability standards should apply to all California balancing authorities, not just the CAISO.

To be equitable and clarify exactly who this exclusion applies to, LADWP recommends that the proposed amendment be revised to apply to a "Balancing Authority" which is a defined term in the regulation, rather than an independent system operator which is not defined. Balancing authorities such as the CAISO and LADWP function the same as the responsible entities that integrate resource plans ahead of time, maintain load-interchange-generation balance within their respective balancing authority areas, and support interconnection frequency in real time.

Recommendation: Therefore, LADWP recommends revising the following sentence in the definition of "Imported Electricity" as follows:

Imported Electricity does not include electricity imported into California by a *Independent System Operator balancing authority to meet NERC Reliability Standards addressing capacity and energy emergencies.* (LADWP 1)

Response: CAISO is not considered an electricity importer under the Cap-and-Trade Regulation. As background, the MRR and Cap-and-Trade Regulation define an electricity importer as the entity identified on the North American Electric Reliability Corporation (NERC) e-Tag as the purchasing-selling entity (PSE) on the last segment of NERC e-tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. As ARB explained in its final statement of reasons submitted to the Office of Administrative Law supporting its Cap-and-Trade Regulation, CAISO is not registered as a PSE, and therefore CAISO does not meet the definition of an electricity importer. However, in order to support some interchange transactions involving emergency assistance between balancing authority areas, CAISO may, from time-to-time, be identified on a NERC e-Tag as a PSE. ARB staff understands that this would be a rare occurrence, and that CAISO is willing to provide ARB staff with aggregated information concerning interchange transactions for emergency assistance on an annual basis.

[227] http://www.wecc.biz/awareness/Reliability!WECC%20RC%200perating%20Procedures/WECC%20RC%20EOP-002%20-%20Capacity%20and%20Energy%20Emergencies.pdf.

Under these circumstances, CAISO merely facilitates the delivery of electricity and is not an electricity importer for purposes of either MRR or the Cap-and-Trade Regulation. The purpose of the language proposed by ARB staff is to clarify that these regulations do not apply to CAISO under these rare circumstances. Aggregated information provided by CAISO will be used by ARB staff to monitor the frequency of these conditions and the amount of power involved to ensure these circumstances continue to be consistent with the goals of Assembly Bill 32.

Based upon the above explanation, ARB staff neither agrees with the commenter that a definition is needed for CAISO nor that an emergency power exemption for the other balancing areas in the State is necessary.

N-5. Comment: As proposed, the definition of Imported Electricity will be revised to include: Energy Imbalance Market (EIM) dispatches designated by the CAISO's EIM optimization model and reported by the CAISO to EIM Participating Resource Scheduling Coordinators as electricity imported to serve retail customers load that is located within the State of California.

Recommendation: PacifiCorp proposes the following revisions:

Energy Imbalance Market (EIM) dispatches designated instructed by the CAISO's EIM market operator optimization model and reported by the CAISO to EIM Participating Resource Scheduling Coordinators as electricity imported into serve retail customers load that is located within the State of California.

This revision is proposed to provide a simplification and clarification of the proposed language. In the EIM proposal, the terms "EIM dispatches" and "designated" are not used in the manner currently proposed in the revised definition of Imported Electricity. The ISO market operator instructs the dispatch of EIM Participating Resources. In addition, according to the way the optimization model is designed, the ISO market operator will only identify and report electricity imported into California where California is the final destination – it will not identify energy wheeled through California. Therefore the language "to serve retail customer load located within the State of California" is superfluous. (PACIFICORP)

Response: ARB appreciates the comment and explanation provided by the commenter, however, we decline to make the requested change as the current language is sufficient given that the EIM market design has not been finalized through FERC approval. ARB staff believes the proposed language provides implementation flexibility for when the EIM market design is finalized. Because the EIM market will include electricity imports to California and is expected to be operational by the time these amendments take effect, it is important for ARB to include regulatory language to ensure that these imports are captured in the

Cap-and-Trade Program. CAISO’s EIM proposal and draft tariff language are sufficient for ARB to develop initial regulatory language around EIM imports, and could be modified in future amendments if necessary.

O. MRR

System Emission Factor

O-1. Multiple Comments: Under proposed section 95111(b)(5) of the MRR, ARB proposes to calculate a system emission factor for all system power suppliers for use in determining emissions associated with system power. ARB also introduces a definition of system power in section 95102(451), which will apply in cases where the carbon intensity of the system power supplier's weighted average power output is greater than the default emission factor. Essentially, in adding this definition, ARB has created a new category wherein the requirements that currently apply to ACS entities will apply to entities whose system emission factor is greater than the default emission factor. However, instead of being voluntary, similar to the current ACS designation, this new category will be mandatory and will apply an emission calculation generated by ARB.

PacifiCorp continues to have significant concerns, further evidenced by the changes described above, regarding what is increasingly becoming ARB's attempt to regulate wholesale power markets in the West and ARB's attendant lack of authority over those wholesale power markets, inside and out of California. Allowing or requiring the use of system emission factors for some subset of (or all) entities in the West is discriminatory and has the effect of setting a different price for the energy from one specific wholesale market participant versus another. It also creates a situation where each wholesale product must be tracked from source to sink. Because wholesale market products are generally from unspecified resources and not differentiated by system, the application of system emission factors has the potential to cause a significant shift in the entire market. It is therefore highly likely that ARB's shift toward system-specific pricing will result in unintended consequences.

PacifiCorp understands ARB's motivation and shift toward system emission factors. Indeed, this approach may be consistent with the intent of the MRR and the Cap-and-Trade Program, which is specifically designed to ensure that a carbon price is incorporated into commodity pricing. However, as will be described in detail below, ARB does not have the jurisdiction or authority to regulate imported power or electricity importers, or to modify the bilateral wholesale market to accommodate system-specific pricing.

Further, it is problematic that ARB does not currently have an effective enforcement mechanism for ensuring that system specific or resource specific emission factors are consistently applied or claimed. This again would require greater jurisdiction over the wholesale energy markets. ARB does not have the authority or jurisdiction to impose its program outside of the state of California or on the wholesale market.

The issue of "leakage" that ARB is attempting to address by calculating system emission factors is simply not one that ARB currently has the authority to resolve. ARB's regulations should recognize ARB's limited jurisdiction and not seek to regulate energy imports or importers. PacifiCorp recommends that the greenhouse gas ("GHG") obligation and cost associated with energy imports or importers be the obligation of the source (load) utilizing the energy. ARB has the authority to regulate costs and obligations associated with GHG in the state of California. The GHG obligation associated with energy that is imported into California should fall to the load in California and not be an obligation of the out of state energy importer. This could be achieved if ARB required all system power (include that from ACS entities) be deemed unspecified and apply the default emission factor, regardless of the entity, into the economics of the entity purchasing the energy to serve load. Parties serving load in California would factor in the cost of the GHG associated with energy from out of state prior to purchasing the imported energy. Further detail regarding the legal basis for why ARB does not have authority over wholesale power markets or imported power is provided below. (PACIFICORP)

> **Response:** The comments are outside of the scope of changes proposed under the Cap-and-Trade Regulation so no response is required. However, this comment was responded to in the FSOR for MRR (Comment B-6c.), available at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013fsor.pdf.

Comment: Calculating GHG Emissions of Imported Electricity Supplied by System Power Suppliers (§ 95111(b)(5)): CARB is proposing that in the event system power imports are above the default emission factor for unspecified electricity imports, if the electricity is not tagged as originating from unique specified sources of generation but instead tagged as system power, it cannot be claimed as coming from an unspecified source. Conversations with CARB staff have indicated the potential for retroactive applicability of this rule.

This proposed change will create a significant level of uncertainty for wholesale market participants transacting in the California electricity market. Such transactions often include packaged electricity that originates from multiple sources having different emission factors. Tracing each electron to its source under such circumstances will not be feasible and will leave participants wondering how to comply. Such a result can be expected to have the undesired effect of reducing entry into the California import market, thereby decreasing liquidity and potentially creating supply problems therein.

In discussing this issue with CARB staff, APS was informed that if APS does not register as an asset-controlling supplier, CARB will calculate and assign a system rate to APS. However, as we previously explained to CARB (*see* letter to CARB declaring APS's reporting status under the MRR dated November 19, 2012), the electricity APS sells into the CAISO is from a combination of purchased power and from facilities owned or operated by APS. The MRR in no way prescribes that an out-of-state entity, like APS, selling fungible, excess power serving the bulk power system must register itself to be an asset-controlling supplier. Were such registration required, it would be unlawful for lack of fundamental fairness in that it would require out-of-state generators not purposely engaging in the sale of electricity for delivery to the California grid to register as asset-controlling suppliers notwithstanding the fact that the electricity they send to the CAISO is generated from sources outside of California and, without the generators' knowledge or control, purchased by entities in California for consumption within the state. Such disparate treatment would unfairly penalize out-of-state sellers by making it more expensive for them to sell their electricity to the CAISO.

In any event, to the extent CARB intends for this rule change to apply to transactions consummated prior to its final promulgation, such a result would constitute an impermissible retroactive application. Government agencies may not promulgate a new rule that has a retroactive effect on a regulated entity's prior actions. In other words, CARB may not promulgate and use a new regulation to establish a new requirement that would change the legal consequences of an electricity importer's past conduct. Such an impermissible retroactive application of the law would place an undue burden on the entity. Regulated entities make important decisions and adjust their behavior based on the law in effect at the time, and they should not be penalized by later-enacted regulatory changes having retroactive applicability. California courts recognize the well-established presumption against retroactive application of laws. This presumption is deeply rooted in American jurisprudence, and CARB's actions are constrained by the general requirement that all laws and regulations shall have only future effect unless the text of the authorizing statute explicitly states otherwise.

> We understand CARB is considering withdrawing the proposed language that is the subject of this comment. To the extent this is the case, we support such action for the reasons discussed above. (APS)
>
> **Response:** The comments are outside of the scope of changes proposed under the Cap-and-Trade Regulation so no response is required. However, this comment was responded to in the FSOR for MRR (Comment B-6d.), available at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013fsor.pdf.

Asset Controlling Supplier

O-2. Comment: Reconsideration of Asset-Controlling Supplier Power - Notwithstanding the jurisdictional limitation arguments set forth above, PacifiCorp respectfully suggests that CARB should revisit the ACS designation and rules in light of the ARB goals articulated in the proposed rulemakings and 2013 workshops. Specifically, ACS entities seem to be able to de-designate themselves as a specified source, and sell unspecified rather than specified power, in circumstances in which the generation providing entity of a specified source would not be able de-designate itself as a seller from a specified source with a mandatory emissions factor.

Under 95111(f) of the MRR, specific requirements are set forth related to ACS which includes the development of an ACS-specific emission factor. The following is required: 1) written contract, 2) identification of the resource in the contract, and 3) direct delivery to California. ARB now proposes an amendment to the definition of ACS that states: "Asset Controlling Suppliers are considered specified sources." This change effectively allows ACS entities to select whether they are providing a specified source or energy that is considered ACS energy. The ACS entity could make this choice even for generation coming from the same resource. This is problematic because it allows an ACS entity to sell the same generation, with the same emission profile, at different prices.

Proposed section 95111(a)(5) clearly provides for an ACS power claim to be identified through the first line of the physical path of the e-Tag "specifying the generation control area" of the ACS, with the exception of "path-outs"228 for the Bonneville Power Administration (BPA) as an ACS. An ACS entity should not be able to distinguish if the generation is system or surplus but rather if it is an ACS all the generation should be part of the calculation to determine its emission factor. In addition, an ACS entity should not be permitted to say that the same ACS control area source can have different factors for different buyers that may be directly contracting with that ACS, depending, for example, if the ACS entity is selling from its ACS portfolio or a non-ACS "portfolio" that is registered under the same legal entity or marketing agency. Further, the rules should not allow for an ACS entity to import specified or unspecified power into its balancing authority "sink the generation" and then by an effective de-designation or non-designation, regenerate ACS energy and sell it at a different emission factor. The lack of a transparent and clear method for calculation of the ACS emission factor only further exacerbates the potential that ARB will have difficulty enforcing its rules outside of California or the United States.

Currently, there are two ACS registered entities. PacifiCorp encourages ARB to eliminate ACS entities and require all parties to sell from a specified resource to obtain an emission factor that is not the default rate. To do otherwise results in resources outside of California that give a free premium pricing option to ACS entities that will impact overall wholesale pricing in the Western Electric Coordinating Council.
The ability of ACS entities outside of the state of California to determine whether the identical energy scheduled under identical circumstances does or does not have specified source characteristics or is unspecified power creates concerns and implications on wholesale pricing outside of California. PacifiCorp urges ARB to consider the elimination of ACS as a designation and implement stand-alone contracts, or pools of resources, consistent with the specified resource requirements, to minimize disruption in wholesale markets in the WECC. (PACIFICORP)

> **Response:** The comments are outside of the scope of changes proposed under the Cap-and-Trade Regulation so no response is required. However, this comment was responded to in the FSOR for MRR (Comment B-2f.), available at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013fsor.pdf.

ARB Jurisdiction

The MRR and Cap-and-Trade Program intrude on an area of regulation subject to the exclusive jurisdiction of FERC. The Federal Power Act ("FPA") vests in FERC

[228] Path outs are excess power originally procured as part of U.S federal mandate to serve the operational or reliability needs of a U.S federal system but which are no longer required due to changes in demand or system conditions,

exclusive jurisdiction over, among other things, the rates, terms, and conditions for the sale of electric energy in instate commerce. See, e.g., 16 U.S.C. §§ 824(a), 824d (2006); New York v. FERC, 535 U.S. 1 (2002). Indeed, FERC recently itself held that although it lacks jurisdiction over sales of renewable energy certificates (RECs) standing alone, it has jurisdiction over RECs and allowances when bundled with energy otherwise subject to FERC's jurisdiction See, e.g., WSPP Inc., 139 FERC 61,061 (2012) (finding that (1) an unbundled REC transaction that is independent of a wholesale electric energy transaction does not fall within FERC's jurisdiction under sections 201, 205 and 206 of the FPA, but that (2) a bundled REC transaction, where a wholesale energy sale and a REC sale take place as part of the same transaction, does fall within FERC jurisdiction under FPA sections 205 and 206, as to both the wholesale energy portion of the transaction and the RECs portion of the transaction, and regardless of whether the contract price is allocated separately between the energy and RECs). Further, FERC has also held that, if a wholesale sale of electric energy by a public utility requires the use of an emissions allowance, that sale, and the cost of allowances in connection with it, is subject to review under FPA section 205. Id. at P 23 (citing Edison Elec. Inst., 69 FERC 61,344 at 62,289 (1994) and explaining that such a sale or transfer of an emissions allowance may "affect" the rates a utility charges "for or in connection with" jurisdictional service, which triggers FERC jurisdiction under the language of Section 205 of the FPA). FERC also found in the Edison Electric order that, if the sale or transfer occurs independent of a sale of electric energy for resale in interstate commerce, it is outside of FERC review under FPA Section 205, unless a public utility seeks to flow through the costs in its wholesale rates. Id.
The adoption and use of system emission factors for entities outside California interferes with FERC's regulation of interstate energy transactions because it effectively imposes a different mechanism for pricing wholesale transactions. Legal precedent is clear that state laws cannot interfere with or frustrate federal laws. See, e.g., Printz v. U.S., 521 U.S. 898, 913 (1997) (noting that all state officials have a duty to enact, enforce, and interpret state law in such fashion so as not to obstruct the operation of federal law, and that all state actions constituting such obstruction, even legislative acts, are ipso facto invalid); Felder v. Casey, 487 U.S. 131, 138 (1988) ("'any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield.'") (quoting Free v. Bland, 369 U.S. 663, 666 (1962)); see also De Canas v. Bica, 424 U.S. 351, 357 (1976) ("Of course, even state regulation designed to protect vital state interests must give way to paramount federal legislation.").

FERC has exclusive jurisdiction over wholesale markets. In exercising that jurisdiction, FERC would not be enforcing California's GHG rules or laws. Furthermore, short of an act of congress, FERC's jurisdiction over wholesale power markets is not a substitute for ARB's jurisdiction. While ARB does not have the authority to regulate and enforce wholesale market activities, FERC similarly does not have the authority to regulate or enforce California law. Therefore, unless new laws are passed by the United States congress, neither ARB nor FERC have the ability to regulate and enforce a multi-state cap-and-trade program. (PACIFICORP)

Response: The comments are outside of the scope of changes proposed under the Cap-and-Trade Regulation so no response is required. However, this comment was responded to in the FSOR for MRR (Comment B-6c.), available at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013fsor.pdf.

Duplicative Reporting of Natural Gas Supplier and Consumer

B-5.9. Comment: On July 10, 2013, SMUD commented on the issue of duplicate reporting under the MRR, which is attached hereto for reference. SMUD explained at that time that it owns and operates roughly 76 miles of local gas pipeline that supplies natural gas to four SMUD power plants ("SMUD Local Pipeline System"). These power plants are covered Electricity Generating Units ("EGUs") subject to MRR reporting and Cap-and-Trade compliance obligations. SMUD reports emissions on the EGUs' behalves and likewise receives a direct allocation of GHG allowances on their behalves. SMUD is not a gas fuel supplier to any other industrial facilities or covered entities under the Cap-and Trade Program. However, because the four power plants are "owned" by joint powers authorities ("JPAs"), of which SMUD is the controlling party, and "buy" gas from SMUD, the JPAs meet ARB's literal definition of "end user" under the MRR. Accordingly, SMUD is technically a "publicly-owned natural gas utility" and "LDC" under the MRR, and must report deliveries of natural gas to the plants, and potentially hold compliance instruments for those supplies. Given that SMUD makes all of its deliveries on a pass- through basis to its EGUs, and that deliveries to these end users are subtracted before calculating any compliance obligation, SMUD should have no separate gas LDC compliance obligation under the AB 32 Cap-and-Trade program. Indeed, during a conference call with ARB on September 26, 2013, SMUD was assured by ARB staff that this is the case for 2012 emissions.

However, SMUD remains concerned that different reporting methods for SMUD's EGUs and the SMUD Local Pipeline System could result in a variance in reported emissions on paper that do not exist in reality. The resulting discrepancy could lead to overstatement of a compliance obligation for the pipeline. For example, SMUD reports emissions from its Cosumnes Power Plant (CPP) EGU pursuant to Subpart D of 40 CFR Part 98. To calculate GHG emissions from this facility, SMUD measures the volume of gas flowing into CPP's electric generating system (in MMscf), calculates the fuel heat input (in MMBtu), applies the GHG emission factor, and, where applicable, the global warming potential. Digester gas, which is supplied to CPP from the Sacramento Regional Wastewater Treatment Plant (SRWTP), and biomethane from out-of-state sources are used to supplement the natural gas fuel. Emissions from the biogas sources are deducted from CPP's total emissions. The result is that total covered emissions include only emissions from all natural gas supplied to the plant expressed in carbon dioxide equivalent, exclusive of any emissions from biogas.

By contrast, SMUD reports fuel use for the Local Pipeline System in accordance with Subpart NN of 40 CFR Part 98. Under this regulation, SMUD receives a single heat energy value for the gas delivered at the pipeline from PG&E, as metered in dekatherms at the Winters Interconnection, which is then theoretically allocated to its power plants per fuel volume ratio. The fuel volumetric and heat input values for the pipeline versus the values for the four plants will not match due to slight differences between meters (SMUD's multiple plant meters and one PG&E revenue meter), and potentially in how the fuel is allocated among the plants. More significantly, reporting under Subpart NN does not account for the different compliance obligation of biomass-derived fuel, which will cause a discrepancy between the two results. SMUD believes that these differences in methodologies led to an additional 81,000 metric tons CO2e reported from the SMUD Local Pipeline System in 2012 over the aggregate of emissions from the four power plants.

In previous comments, SMUD has objected that duplicate reporting of pass-through natural gas to its EGUs is overly burdensome and causes unnecessary expense in terms of staff time and verification costs. This is still true. However, the bigger problem is the potential for a compliance obligation on the SMUD Local Pipeline System resulting from the dissimilar reporting methodologies between the pipeline and EGUs. To date, these differences are relatively small and explainable. However, confusion could evolve over time.

SMUD Recommends that the Board Direct ARB Staff to Develop a Minor Amendment to the Cap-and-Trade Regulation to Prevent a Duplicate Compliance Obligation for SMUD's Unique Circumstances.

SMUD is recommending a slight modification to the Cap-and-Trade Regulation to reduce SMUD's exposure for this unique situation. In particular, SMUD recommends adding a new subsection (c)(5) to Section 95852 of the Cap-and-Trade Regulation, as follows:

> **Recommendation:** (c) Suppliers of Natural Gas. A supplier of natural gas covered under sections 95811(c) and 95812(d) has a compliance obligation for every metric ton CO2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California contained in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned, less the fuel that is delivered to covered entities, as follows:
>
> <u>(5) Publicly-owned natural gas utilities that supply natural gas to covered entities which include the utility shall not have a compliance obligation if the utility can demonstrate that its deliveries are made exclusively to the covered entities.</u>

The suggested amendment of the Cap-and-Trade Regulation would be very narrow in scope because it would apply to just publicly-owned natural gas utilities that distribute gas on a pass-through basis. It would also be limited to the situation where all gas supplied by the pipeline is to covered entities, which already report and hold compliance instruments. Most importantly, the proposed amendment would do away with the potential to saddle an electric utility with duplicate liability for a compliance obligation as a result of an internal, pass-through, pipeline system. (SMUD 1)

Response: ARB staff declines to make the requested amendment. As noted in the 2013 MRR FSOR,[229] staff does not expect that the reporting idiosyncrasies under discussion will lead SMUD to have a compliance obligation for its natural gas pipelines. ARB staff further believes that creating an exemption for publicly owned natural gas utilities which deliver exclusively to covered entities could potentially be unfair to other natural gas suppliers that deliver to both covered and uncovered entities.

229 http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013fsor.pdf

V. SUMMARY OF COMMENTS MADE DURING THE 15-DAY COMMENT PERIOD AND APRIL 25, 2014 BOARD HEARING AND AGENCY RESPONSES

Chapter V of this FSOR contains all comments submitted during the 15-day comment period for the proposed amendments, written comments submitted at the April 25, 2014 Board hearing, and oral testimony from the April 25, 2014 Board hearing. The 15-day comment period commenced on March 21, 2014 and ended on April 5, 2014. Additional comments were submitted at the April 25, 2014 Board hearing held for consideration and adoption of the amendments.

ARB received 126 comments on the proposed amendments during the 15-day comment period, and 6 written comments at the April 25, 2014 Board hearing. In addition, 31 commenters gave oral testimony at the April 2014 Board hearing. Commenters included representatives from the electricity and natural gas sectors, environmental non-governmental organizations, the refining sector, offset project developers and offset registries, and representatives from trade groups and academic organizations. Similar to Chapter IV of this FSOR, comments are categorized into one of 13 sections below, and are grouped for response wherever possible.

Table V-1 below lists commenters that submitted oral and written comments on the proposed amendments during the 15-day comment period and at the Board Hearing for final consideration of the proposed regulation order, identifies the date and form of their comments, and shows the abbreviation assigned to each.

A. LIST OF COMMENTERS

Abbreviation	Commenter
AAO	Americans Against Offsets Written Testimony: 04/04/2014
AERA	Gregory Meisinger, Aera Energy Written Testimony: 04/03/2014
ANGELL	J. Angell, Private Individual Written Testimony: 04/02/2014
APC 3	Keith Adams, Air Products and Chemicals, Inc. Written Testimony: 04/04/2014
APEN 2	Rose Mari Taruc, Asian Pacific Environmental Network Written Testimony: 04/02/2014
BARNARD	Gabrielle Barnard, Private Individual Written Testimony: 03/31/2014
BARNES	Kathryn Barnes, Private Individual Written Testimony: 04/02/2014
BEM 2	Margaret Miller, Brookfield Energy Marketing Written Testimony: 04/04/2014
BIOTHERMICA 2	Raphael Bruneau, Biothermica Technologies Inc. Written Testimony: 04/04/2014
BLUESOURCE 2	Eric Townsend, Blue Source LLC Written Testimony: 04/03/2014
BP 2	Ralph Moran, BP America Inc. Written Testimony: 04/04/2014
BP 3	Ralph Moran, BP America Inc. Oral Testimony: 04/25/2014
BRAY	Duncan Bray, Private Individual Written Testimony: 04/01/2014
BUCKLEY	Cathy Buckley, Private Individual Written Testimony: 04/02/2014
BULLA	Jeanne Bulla, Private Individual Written Testimony: 03/31/2014
BURLEY	Chris Burley, Private Individual Written Testimony: 03/31/2014
BUXTON	Nick Buxton, Private Individual Written Testimony: 03/31/2014
CALPINE 4	Kassandra Gough, Calpine Corporation Written Testimony: 04/04/2014
CAR 3	Katy Young, Climate Action Reserve Oral Testimony: 4/25/2014
CCCSD 2	Curtis Swanson, Central Contra Costa Sanitary District Written Testimony: 3/27/2014

Abbreviation	Commenter
CCEEB 2	Robert Lucas, Council for Environmental and Economic Balance Written Testimony: 04/04/2014
CCEEB 3	Robert Lucas, Council for Environmental and Economic Balance Oral Testimony: 04/25/2014
CCEEB 4	Robert Lucas, Council for Environmental and Economic Balance Written Testimony: 04/25/2014
CE2CAPITAL 4	Greg Arnold, CE2 Carbon Capital Oral Testimony: 04/25/2014
CE2CAPITAL 5	Tony Brunello, C2E Carbon Capital Oral Testimony: 04/25/2014
CFEA 6	Jon Costantino, Coalition for Fair and Equitable Allocation Written Testimony: 04/04/2014
CFEA 7	Jon Costantino, Coalition for Fair and Equitable Allocation Oral Testimony: 4/25/2014
CHEVRON 6	Michael Rubio, Chevron Corporation Written Testimony: 04/04/2014
CHEVRON 7	K.C. Bishop, Chevron Corporation Oral Testimony: 04/25/2014
CHUNG	Kate Chung, Private Individual Written Testimony: 04/04/2014
CLFP 3	John Larrea, California League of Food Processors Written Testimony: 04/04/2014
CLIMECO	William Flederbach, ClimeCo Corporation Written Testimony: 04/04/2014
CMORRISON	Cynthia Morrison, Private Individual Written Testimony: 03/31/2014
CORREA	Senator Lou Correa, 34th District Written Testimony: 04/25/2014
COVANTA 2	Ellie Booth, Covanta Energy Written Testimony: 04/04/2014
CPM 2	Carl Fink, Capital Power Marketing Inc. Written Testimony: 04/04/2014
CRS 2	Alex Pennock, Center for Resource Solutions Written Testimony: 04/04/2014
CULLENWARD 3	Danny Cullenward, Private Individual Written Testimony: 04/04/2014
CULLENWARD 4	Danny Cullenward, Private Individual Oral Testimony: 4/25/2014
CUNNINGHAM	Trina Cunningham, Private Individual Written Testimony: 03/31/2014
DENHERDER	Timothy DenHerder-Thomas, Private Individual Written Testimony: 03/31/2014

Abbreviation	Commenter
DESENZE	Kristina DeSenze, Private Individual Written Testimony: 03/31/2014
DRZARRO	Dr. Zarro, Private Individual Written Testimony: 03/31/2014
DUBE	Eric Dube, Private Individual Written Testimony: 04/02/2014
ECC	Ben Apple, Environmental Commodities Corporation Written Testimony: 04/04/2014
EDF 3	Tim O'Connor, Environmental Defense Fund Oral Testimony: 04/25/2014
EDWARDS	Jake Edwards, Private Individual Written Testimony: 03/31/2014
ENCORE	Joe Gershe, Encore BioRenewables Written Testimony: 04/03/2014
EOS	Todd English, EOS Climate Written Testimony: 04/04/2014
EPA 2	Cate Hight, U.S. Environmental Protection Agency Written Testimony: 04/03/2014
ERMINESKIN	Frank A. Ermineskin, Private Individual Written Testimony: 03/31/2014
ESI	Janice McMahon, Environmental Services, Inc. Written Testimony: 04/03/2014
EVANS	Victoria Evans, Carbon Venture Partners Written Testimony: 04/01/2014
GARLENA	Sharon Garlena, Private Individual Written Testimony: 03/31/2014
GILLESPIE	Sherri Gillespie, Private Individual Written Testimony: 04/03/2014
GLASS	Emily Glass, Private Individual Written Testimony: 03/31/2014
GREEN 2	Jerry Gureghiam, Green Holdings Oral Testimony: 04/25/2014
HAYES	Linda Hayes, Private Individual Written Testimony: 03/31/2014
HCE 2	Delvan Worley, Holy Cross Energy Written Testimony: 04/03/2014
HO	Kit Ho, Private Individual Written Testimony: 04/03/2014
IDE	Taku Ide, Private Individual Written Testimony: 04/04/2014
IEPA 3	Amber Riesenhuber, Independent Energy Producers Association Written Testimony: 04/04/2014

Abbreviation	Commenter
IETA 2	Dirk Forrister, International Emissions Trading Association Written Testimony: 04/04/2014
JARSOCRAK	Lynda Jarsocrak, Private Individual Written Testimony: 03/31/2014
KC 2	Dell Majure, Kimberley-Clark Written Testimony: 04/04/2014
KC 3	Dell Majure, Kimberley-Clark Oral Testimony: 04/25/2014
KC 4	Dell Majure, Kimberley-Clark Written Testimony: 04/25/2014
KERN 6	Melinda Hicks, Kern Oil & Refining Co. Written Testimony: 04/04/2014
KERN 7	Jake Belin, Kern Oil & Refining Co. Oral Testimony: 04/25/2014
KISSAM	Sandra Kissam, Private Individual Written Testimony: 04/01/2014
LADWP 3	Jodean Giese, Los Angeles Department of Water & Power Written Testimony: 04/04/2014
LIQUIDE	Dwayne Phillips, Air Liquide Large Industries Written Testimony: 04/04/2014
LMORRISON	Lori Morrison-Contreras, Private Individual Written Testimony: 03/31/2014
LOHMANN	Larry Lohmann, Private Individual Written Testimony: 03/31/2014
LOURENCO	Sonja Lourenco, Private Individual Written Testimony: 03/31/2014
LTC 3	Grant Aguinaldo, Lunday-Thagard Co. Written Testimony: 04/04/2014
LW	Robert A. Wyman, Jr., Latham & Watkins Written Testimony: 04/04/2014
MAES	Linda Maes, Private Individual Written Testimony: 03/31/2014
MARCINIAK	Laura Marciniak, Private Individual Written Testimony: 03/31/2014
MARKS	Luan Marks, Private Individual Written Testimony: 04/04/2014
MARTINEZ	John Martinez, Private Individual Written Testimony: 04/02/2014
MILLER	Barbara Miller, Private Individual Written Testimony: 04/02/2014
MOORE	Emily Moore, Private Individual Written Testimony: 04/01/2014

Abbreviation	Commenter
MOTL	Julie Motl, Private Individual Written Testimony: 03/31/2014
MSR 2	Susie Berlin, Law Offices of Susie Berlin (MSR Public Power Agency) Written Testimony: 04/04/2014
MWD 3	Jeffrey Kightlinger, Metropolitan Water District Witten Testimony: 04/04/2014
MWD 4	Kathleen Cole, Metropolitan Water District Oral Testimony: 04/25/2014
NCPA 3	Susie Berlin, Law Offices of Susie Berlin (for Northern California Power Agency) Written Testimony: 04/04/2014
NCPA 4	Susie Berlin, Law Offices of Susie Berlin (for Northern California Power Agency) Oral Testimony: 04/25/2014
NES	Milena Nes, Private Individual Written Testimony: 04/01/2014
NEWFORESTS	Brian Shillinglaw, New Forests Written Testimony: 04/04/2014
NOBLE 2	Thomas Corr, Noble Americas Energy Solutions LLC Written Testimony: 04/04/2014
NORRGARD	Lois Norrgard, Private Individual Written Testimony: 03/31/2014
PACIFICORP 2	John Apperson, PacifiCorp Written Testimony: 04/25/2014
PANOCHE 2	David Huard, Manatt Phelps & Phillips LLC (for Panoche Energy Center LLC) Written Testimony: 04/04/2014
PARAMOUNT 4	Gary Grimes, Paramount Petroleum Written Testimony: 04/04/2014
PARAMOUNT 5	Gary Grimes, Paramount Petroleum Oral Testimony: 04/25/2014
PARAMOUNT 6	Steve Piatek, Paramoung Petroleum Oral Testimony: 04/25/2014
PARAMOUNT 7	Gary Grimes, Paramount Petroleum Written Testimony: 04/25/2014
PARAMOUNT 8	Steve Piatek, Paramount Petroleum Written Testimony: 04/25/2014
PERKINS	Timothy Perkins, Private Individual Written Testimony: 03/31/2014
PG 2	Kara Roeder, The Procter & Gamble Paper Products Company Written Testimony: 03/30/2014

Abbreviation	Commenter
PG 3	Kara Roeder, The Procter & Gamble Paper Products Company Oral Testimony: 4/25/2014
PGE 4	Mark Krausse, Pacific Gas & Electric Written Testimony: 04/04/2014
PGE 5	Claire Halbrook, Pacific Gas & Electric Oral Testimony: 04/25/2014
PH 3	Peter Weiner, Paul Hastings LLP Written Testimony: 04/04/2014
PH 4	Peter Weiner, Paul Hastings LLP Oral Testimony: 04/25/2014
PHILLIPS 6	Stephanie Williams, Phillips 66 Written Testimony: 04/04/2014
POWEREX 2	Nicholas van Aelstyn, Beveridge & Diamond (for Powerex Corporation) Written Testimony: 04/04/2014
PRAXAIR 3	Gerald Miller, Praxair, Inc. Written Testimony: 04/03/2014
RCE 4	Michael Cote, Ruby Canyon Engineering Oral Testimony: 04/25/2014
RUBY	Kenneth Ruby, Private Individual Written Testimony: 03/31/2014
SAEGER	Ron Saeger, Private Individual Written Testimony: 03/31/2014
SCE 4	Nancy Allred, Southern California Edison Company Written Testimony: 04/04/2014
SCE 5	Adam R. Smith, Southern California Edison Company Oral Testimony: 04/25/2014
SCGE 2	Jerilyn Lopez Mendoza, Southern California Gas Company and San Diego Gas and Electric Company Oral Testimony: 04/25/2014
SCS	Christie Pollet-Young, SCS Global Services Written Comments: 04/04/2014
SEMPRA 3	Katy Wilson, Sempra Generation Written Testimony: 04/04/2014
SEMPRA 4	Tamara Rasberry, Sempra Utilities Written Testimony: 04/04/2014
SHATTUCK	Annie Shattuck, University of California Berkeley Written Testimony: 04/01/2014
SHELL 2	Teresa Makarewicz, Shell Oil Products US Written Testimony: 04/04/2014
SHELL 3	Marcie Milner, Shell Energy North America Written Testimony: 04/04/2014

Abbreviation	Commenter
SHELL 4	Teresa Makarewicz, Shell Oil Products US Oral Testimony 04/25/2014
SHELL 5	Marcie Milner, Shell Energy North America Oral Testimony: 04/25/2014
SIGLER	Greg Sigler, Private Individual Written Testimony: 03/31/2014
SIMON	Saundra Simon, Private Individual Written Testimony: 03/31/2014
SLADE	Donna Slade, Private Individual Written Testimony: 03/31/2014
SOLIZ	Marisa Soliz, Private Individual Written Testimony: 03/31/2014
SOLVAY 2	Ron Hughes, Solvay Written Testimony: 04/04/2014
SOPHINA	Anglique Sophina, Private Individual Written Testimony: 04/04/2014
STANFORD 5	Barbara Haya, Stanford Law School Written Testimony: 04/04/2014
STANFORD 6	Barbara Haya, Stanford Law School Oral Testimony: 04/25/2014
STANFORD 7	Emily Grubert, Stanford Law School Oral Testimony: 04/25/2014
STOCK	Sarah Stock, Private Individual Written Testimony: 03/31/2014
TA	Braydon Boulanger, TransAlta Written Testimony: 04/04/2014
TAYLORR	Jeremy Taylorr, Private Individual Written Testimony: 03/31/2014
TESORO 3	Miles Heller, Tesoro Written Testimony: 04/04/2014
TESORO 4	Miles Heller, Tesoro Written Testimony: 04/04/2014
TESORO 5	Miles Heller, Tesoro Oral Testimony: 04/25/2014
THERULES	Alnoor Ladha, The Rules Written Testimony: 04/01/2014
THORNBURGH	Jack Thornburgh, Peninsual EcoVision Written Testimony: 04/02/2014
TID 3	Ken Nold, Turlock Irrigation District Written Testimony: 04/04/2014
TOOLE ONEIL 2	Barbara Toole O'Neil, Private Individual Written Testimony: 04/04/2014

Abbreviation	Commenter
TOOLE ONEIL 3	Barbara Toole O'Neil, Private Individual Oral Testimony: 04/25/2014
UNECE	Raymond Pilcher, United Nations Economic Commission for Europe Written Testimony: 04/04/2014
USG	John Bolden, United States Gypsum Company Written Testimony: 04/04/2014
USW 5	Robert LaVenture, United Steelworkers Written Testimony: 04/04/2014
VESSELS 3	Thomas Vessels, Vessels Coal Gas, Inc. Written Testimony: 04/04/2014
VESSELS 4	Thomas Vessels, Vessels Coal Gas, Inc. Oral Testimony: 04/25/2014
WATERS	John Waters, Private Individual Written Testimony: 03/31/2014
WHEELOCK	Dave Wheelock, Private Individual Written Testimony: 03/31/2014
WILDFLOWER 3	Paul Shepard, Wildflower Energy Written Testimony: 04/04/2014
WILDFLOWER 4	Paul Shepard, Wildflower Energy Oral Testimony: 04/25/2014
WM 3	Charles White, Waste Management Written Testimony: 04/02/2014
WONG	Helena Wong, Private Individual Written Testimony: 03/31/2014
WOOD	Walter Wood, Private Individual Written Testimony: 04/03/2014
WPTF 3	Clare Breidenich, Western Power Trading Forum Written Testimony: 04/04/2014
WREA	Scott Foster, Western Renewable Energy Analysts, Inc. Written Testimony: 04/03/2014
WSCC	Sarah Sauter, Western Slope Conservation Center Written Testimony: 04/03/2014
WSPA 5	Catherine Reheis Boyd, Western States Petroleum Association Written Testimony: 04/04/2014
WSPA 6	Mike Wang, Western States Petroleum Association Oral Testimony: 04/25/2014
YYEW	Y. Yew, Private Individual Written Testimony: 03/31/2014
ZHOU	Maggie Zhou, Private Individual Written Testimony: 03/31/2014

B. ALLOWANCE ALLOCATION

B-1. Facility Closure

Applicability to Electric Distribution Utilities

B-3.1. Comment: Section 95812(f) – Entities that Cease Operations. Section 95812(f) addresses the treatment of freely allocated allowances for covered entities that cease operations. NCPA appreciates the revisions that specifically reference a "covered entity" ceasing operations rather than the previous language that referenced an entity that "receives a direct allocation of allowances pursuant to section 95870." In order to ensure that there is no potential for ambiguity in this section, NCPA urges the Board to direct that an additional, minor modification be added to this language to reflect the prior oral assurances that this provision applies only to the industrial sector allocations and not EDUs. (NCPA 3)

> **Response:** As discussed at the October 25, 2013 Board hearing, staff believes the language in Section 95812(f) and (g) is sufficiently clear. ARB staff intends this provision to apply only to industrial covered facilities, and does not intend to require the return of allowances in the case that an EDU shuts down an electricity generation facility. Consequently, given the stated intent of the provision, staff does not believe that additional text or clarification is required. ARB staff will continue working with EDUs to ensure that our efforts to incentivize greenhouse gas reductions in the electricity generation sector are effectively carried out consistent with State energy goals.

Support for Provision and Public Process

B-3.2. Comment: Facility Shutdown. We appreciate and support the changes made by ARB in the proposed 15-day package. (WSPA 5)

> **Response:** Thank you for the support.

Return of Allowances

B-3.3. Comment: §95812(f)(3) - Disposition of allowances deriving from shutdowns The Draft proposes to retire allowances that were freely allocated to facility shutdowns subsequent to the calendar year the facility ceased operation, reducing allowances in circulation. Retirement of allowances represents reduced emissions. Instead, these allowances, which do not represent actual emissions, should be placed into the allowance budget for use by the market. Staff has suggested that free allowances that are surrendered from a shutdown would be returned to the market save those required to cover actual emissions from that facility. CCEEB agrees with this approach and are willing to work with Staff on developing a mechanism for returning these allowances to the market. (CCEEB 4)

> **Response:** This comment was originally submitted for the discussion draft of the proposed regulation order, which was released for public consideration on

January 31, 2014 and accompanied by an informal 15-day comment period. As this comment pertains to the informal discussion draft, no response is required. However, the commenter also submitted this comment letter at the April 25, 2014 Board hearing and therefore staff have included a response in this FSOR.

The commenter refers to section 95812(f)(3) of the discussion draft regulation order, which was modified and moved to 95812(f)(4) in the final proposed regulation order, as considered by the Board at the April 25, 2014 public hearing. In the final proposed regulation order, staff modified this section to state that all returned allowances will be auctioned pursuant to section 95910. Therefore, the commenter's suggestion that the allowances be auctioned on behalf of the state has been incorporated into the final regulation order.

B-2. Legacy Contracts

Support for Proposal

B-2.1. Multiple Comments: The Independent Energy Producers Association (IEP) supports the Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, released March 21, 2014. With regards to these proposed amendments, IEP's primary issue has been the treatment of legacy contracts without a means for greenhouse gas cost recovery.

We are pleased to report that IEP's concerns with regards to legacy contracts have been resolved.

IEP appreciates CARB's attention and willingness to work on the legacy contract issue with us. We wish to take this opportunity to commend the staff and management for their efforts to address and resolve the important issues associated with legacy contract holders which were so critical to the continued operations of these entities. The staff and management worked with IEP and others in detail, and we certainly appreciate their focus and willingness to consider viable solutions. We look forward to working with CARB staff in the future. (IEPA 3)

Comment: On behalf of Waste Management (WM) and its subsidiary Wheelabrator Technologies, we wish to comment on the 15-Day Modifications to the California Cap on Greenhouse Emissions and Market-Based Compliance Mechanisms released March 21, 2014. Our comments are focused on proposed amendments impacting legacy contracts. We strongly support the revisions to the legacy contract provisions. Providing for transitional assistance through two triennial compliance periods is necessary to ensure that Legacy Contract generators do not face an untenable financial situation due to their inability to pass through GHG costs.

We appreciate ARB's proposal to provide recovery by assigning allowances to the Norwalk facility and other similarly situated power plants without cost recovery. Thank you for this opportunity to provide comments. We look forward to working with you to resolve this important issue. (WM 3)

Comment: We fully support CARB staff's proposal in the Modified Regulation Order to provide relief to legacy contract generators through 2017. We believe this approach will provide the necessary transition assistance to the majority of legacy contact generators. Importantly, such relief will permit highly efficient electricity producing and CHP facilities—the very facilities the Regulation is designed to promote—to continue to operate. In particular, if the Board adopts the Modified Regulation Order, the substantial risk of credit downgrades, which threatens the ability of certain legacy contract generators to finance debt and raise capital, is expected to be alleviated. (PH 2)

Comment: Wildflower has a Pre-AB 32 long-term contract with a non-utility power marketer that lasts through the duration of the Cap-and-Trade program. The contract does not expressly contemplate any greenhouse gas ("GHG") control program or treatment of such program compliance costs, and this new cost burden poses a serious threat to the continued financial viability of Wildflower's fast starting power plants located in Southern California.

Wildflower supports the Amendments to Sections 95891 and 95894. Wildflower believes that the amendments are a fair approach that will achieve the ARB's policy objectives of encouraging parties to renegotiate their legacy contracts, while at the same time, minimizing the risk of facilities shutting down due to their inability to pass through greenhouse gas compliance costs. Wildflower's good faith efforts to renegotiate its legacy contract to explicitly address greenhouse gas costs have been unsuccessful. However, Wildflower is hopeful that the adoption of the amendments to Sections 95891 and 95894 will ultimately lead to a reasonable amendment to Wildflower's Legacy Contract. Wildflower offers the following specific comments on the proposed amendments to Section 95891 and 95894.

I. The Amendments to Sections 95891 and 95894 Would Neither Penalize Counterparties to Legacy Contracts Nor Provide a Competitive Advantage to Legacy Contract Generators.

One of the fundamental policy objectives of the Cap-and-Trade is to create a carbon price signal. In most cases, the counterparties to Legacy Contracts have been able to avoid internalizing GHG price signals because the generators are directly responsible for procuring emissions allowances. As amended, Section 95891 would remove allowances from an industrial counterparty's free allocation if the industrial counterparty (or direct associate) refuses to pay for the GHG costs. The effect of this amendment (i.e., the redistribution of allowances) will be to treat the industrial counterparties consistently with all other counterparties that are paying for GHG costs.

This redistribution is particularly important for Wildflower's facilities because they operate under a tolling contract where the counterparty controls the dispatch of the facilities. The facilities are presumably dispatched based on economics of the contract relative to market conditions. In other words, the counterparty controls the GHG emissions of Wildflower's facilities. The ability to avoid AB 32 costs artificially makes the Wildflower facilities appear less expensive compared to other resources in the market where the sellers (e.g., other marketers) have paid for GHG costs. If the ARB redistributes allowances through the Amendments to Section 95891 and 95894, the marketer will be required to internalize the GHG costs and the carbon price will be passed through like other power plants controlled by marketers. Thus, the counterparty is not being penalized by the amendments to Section 95891 and 95894 when compared to the treatment of other marketers.

Moreover, an industrial counterparty can avoid redistribution of allowances if it or the direct corporate associate renegotiates the Legacy Contract to address GHG costs. Alternatively, for Wildflower's facilities, the counterparty could choose to not dispatch the facilities. If the facilities are not dispatched at all, there would be no emissions obligation and there would be no redistribution of allowances after 2014. Either way, the redistribution is within the counterparty's control.

2. The Amendments to Sections 95891 and 95894 Would Not Disrupt the ARB's Policies of Minimizing Risks of Trade Exposure To EITE Industries.

As amended, Section 95891 and 95894 would remove allowances from an industrial counterparty to a legacy contract if the parties do not renegotiate the Legacy Contract. If the counterparty to a legacy contract is a direct corporate associate of an entity receiving free allocation as an "Emissions Intensive Trade Exposed" ("EITE") entity, then the EITE entity lose a portion of their free allocation based on the emissions associated with the Legacy Contract. Since the allowances will initially be allocated from a future compliance period (i.e., 2015 allowances), the EITE entity will have more than enough time to procure allowances and adjust its compliance strategy before the next surrender obligation becomes due. Moreover, there will be ample time for the EITE entity (or the direct corporate associate of the EITE entity) to engage in bilateral negotiations to amend the Legacy Contract and avoid the redistribution all together. Thus, the amendments to Sections 95891 and 95894 will not put EITE entities at any greater risk of trade exposure.

3. The ARB's Nuanced Approach in Section 95894 is Appropriate Given the Diversity of Legacy Contracts.

Wildflower supports the ARB's efforts to develop a multifaceted approach in Section 95894. Section 95894 represents an appreciation for the fact that there are a multitude of different types of generators operating under various contractual structures that expire at different points in time. A "one-size fits all" approach would not have been an effective solution to the Legacy Contract issue. In those cases where the ARB can encourage the counterparty to renegotiate by redistributing allowances (i.e., by withholding free allocation from industrial counterparties), the ARB will fulfill the policy of encouraging renegotiation as the preferred solution to the Legacy Contract issue. (WILDFLOWER 3)

Comment: The 15-Day Changes Fairly And Equitably Resolve The Concerns of Legacy Contract Generators. Calpine strongly supports CARB's approach to resolving the long-standing issue of how best to provide appropriate relief to electricity generators subject to legacy contracts entered into prior to the enactment of Assembly Bill ("AB") 32 that do not allow for recovery of GHG compliance costs for electricity and/or thermal energy delivered pursuant to the contract.

Calpine has consistently advocated for a fair resolution of the legacy contract issue and has, whenever possible, renegotiated pre-AB 32 contracts to address GHG costs. Despite Calpine's good faith efforts to bring our counterparties to the negotiating table, we have not been able to renegotiate four remaining legacy contracts to allow for the pass-through of compliance costs associated with deliveries of electricity and/ or steam from our combined heat and power ("CHP") facilities.

The 15-Day Changes fairly and appropriately resolve this issue: Where a legacy contract counterparty will receive an allocation for industrial assistance, but will not experience an increase in its steam or electricity costs due to the existence of the legacy contract, the emissions attributable to generation of steam and/or power pursuant to that contract should be deducted from the counterparty's allocation and provided to the generator instead. Calpine therefore believes the Proposed Amendments appropriately balance the interest in incentivizing renegotiation of contracts, with the reality that some industrial counterparties have little to no interest in renegotiating their existing contracts to share in the burden imposed by the Cap-and-Trade compliance obligation. Calpine also appreciates CARB's additional proposed amendment to section 95870(g) to clarify that legacy contract allocations will be provided through 2017. (CALPINE 4)

Comment: PEC is a large natural gas peaking plant with a tolling contract for the exclusive sale of electric power to Pacific Gas & Electric Company ("PG&E") that was executed in March 2006 ("PEC PPTA"). PEC's PPTA does not specifically address or allow for the recovery of GHG compliance costs. PEC's comments are limited to relief for legacy contract generators and legacy contracts. PEC participated throughout the regulatory process and has previously submitted comments on the earlier draft proposals.

Board Resolution 12-33, issued September 20, 2012, states: "WHEREAS, entities with legacy contracts that were entered into prior to AB 32 may not have an appropriate mechanism for recovery of carbon costs associated with the Cap-and-Trade Regulation: ..." The Resolution further states: "BE IT FURTHER RESOLVED that the Board directs the Executive Officer to develop a methodology that provides transition assistance to covered entities that have a compliance obligation cost that cannot be reasonably recovered due to a legacy contract." PEC supports this policy objective and views the initial five years of relief as absolutely necessary.

Though Staff has consistently expressed a preference for renegotiations between parties to these legacy agreements, these amendments concede that negotiations have not been successful for all parties at this point in time. Over the last two years, PEC has attempted to engage in good faith negotiations with its legacy contract counterparty. PEC will continue to pursue resolution of its issues but joins other legacy contract generators in the belief that settlement of the remaining disputes between legacy contract holders and their counterparties is unlikely, as those counterparties have no business incentive to negotiate a resolution at this time. And in fact, PEC's counterparty has consistently been the primary opposition to providing transition relief to any Legacy Contract Generator. Therefore, PEC believes this issue may likely need to be revisited by CARB in the future.

Additionally, on March 19, 2014, the Public Utilities Commission ("CPUC") issued a decision (14-03-003) establishing Commission policy on GHG cost responsibility for contracts executed prior to the passage of AB 32, and deferring to CARB the authority to establish the criteria by which legacy contract holders may receive transition assistance. The CPUC restated its earlier position that GHG costs, and responsibility for such costs, should be clearly articulated in Legacy Contracts in order to account for GHG costs in generation dispatch decisions. Consistent with CARB's policy, utilities were further ordered to continue renegotiating contracts to include provisions to ensure that generators party to Legacy Contracts receive compensation for their GHG costs.

For the foregoing reasons, PEC supports providing the proposed relief to legacy contract holders using the eligibility criteria provided.

1.COMMENT DETAILS

a. Eligibility Criteria

PEC continues to support the eligibility criteria for legacy contracts to qualify for relief applicable to PEC (Section 95894):

- Contract was executed before September 1, 2006;
- Contract does not allow for recovery of the costs associated with compliance with the Cap and Trade Regulation;
- Contract remains in place and has not been subsequently amended to address GHG compliance costs; and
- The Legacy Contract holder has made a "good faith" effort to renegotiate with contract counterparty to address GHG costs issues.

PEC supports these straightforward criteria.

b. Process for Receiving Allocations

The process for allocation of allowances to Legacy Contract Generators generally consists of a request by the legacy contract generators and a subsequent eligibility determination by the CARB Executive Officer. PEC supports this simple administrative criteria.

c. Process for Determination of Eligibility

PEC understands the intent of Section 95894(b) to be relatively straightforward, but seeks clarity in either the final Board Resolution or in response to comments in the Final Statement of Reason that the "Determination of Eligibility" is a compliance process by which CARB will review and process the filings. PEC further believes that such information must be treated by CARB as confidential in that sensitive market and pricing information is required for submittal.

PEC supports the need for CARB Staff to review sufficient detail to determine whether the generator qualifies for the proposed transition relief. However, PEC requests that CARB confirm that the process will be an internal compliance process conducted by CARB, not subject to a public review and comment process, especially as market-sensitive pricing information is required for submittal. (PANOCHE 2)

Comment: Good morning. My name is Paul Shepard. I'm the Asset Manager for Wildflower Energy. Wildflower Energy is the generator of a pre-AB 32 long-term contract. I'm here today to express our support for the proposed revisions to Section 95894 and 95891. We urge the Board to adopt these amendments as is it is today. Wildflower appreciates the Board's policy that renegotiation is a preferred solution to the legacy contracts issue. In many cases, counterparties have been unwilling to renegotiate to reach negotiated solution. And we believe that the Board's actions today will encourage counterparties to come forward with a fair and balanced proposal for the pasture greenhouse gas costs in the legacy contracts to the ultimate end users. In this regard, staff's proposal is fair and balanced. And we encourage renegotiation of the contracts. I will also briefly address some of the comments that have been made in opposition to the proposed amendments. We do not agree that redistribution of the allowances to legacy contract holders will disrupt the compliance strategies of the counterparties. In our case, our emissions are just two percent of our counterparty's estimated emissions. In addition, the allocations under Section 95894 will be for future compliance periods. And our counterparties to these contracts will have more than enough time and opportunity to procure additional allowances. It has also been argued since staff's proposed legacy contract language, legacy contract holders now have no incentive to renegotiate. We do not agree with this assertion. If adopted, the staff proposal will leave an increasing proportion of compliance obligations uncompensated for by the reallocated allowances. And thus, holders of legacy contracts will be able to renegotiate with the counterparty to obtain a more complete solution. In our case, we have put forth proposals for a reasonable pasture of greenhouse gas costs and are actively pursuing discussions with our counterparty. In closing, we hope that the Board's adoption of the regulations today we will be able to reach a reasonable compromise with our counterparty, consistent with the ARB policy of having end users of greenhouse gas generating commodities see the cost the greenhouse gas generated. (WILDFLOWER 4)

Response: Thank you for the support.

Clarification of Legacy Contract

B-2.2. Comment: The ARB Should Clarify that Sections 95802(a)(206) and 95891 are Meant to Be Consistent with Section 95894.

Wildflower requests that the ARB clarify in its Final Statement of Reasons that when the Regulation refers to: (1) "Legacy Contract Generator with an Industrial Counterparty" in Section 95802(a)(206) and (2) "Legacy Contracts" in Section 95891, the ARB is referring to Legacy Contracts where the counterparty (or entity in a direct corporate association with the counterparty) is a covered entity or opt in covered entity that is in a sector listed in Table 8-1. This clarification would ensure that these sections are intended to be consistent with Section 95894(c). (WILDFLOWER 3)

Response: ARB staff disagrees that the clarification about “industrial counterparty” is necessary because the only entities eligible for industrial allocation pursuant to 95891 are covered entities or opt-in covered entities with a NAICS code and associated activity listed in Table 8-1 of the Regulation.

B-2.3. Comment: Allocation of Allowances to Legacy Contract Generators. As we stated in our February 14, 2014 comment letter, Air Liquide strongly supports CARB's decision to allocate allowances to covered entities that supply electricity and thermal energy (including steam generated in connection with the production of hydrogen) to third parties under long-term, fixed-price "legacy contracts" executed before September 1, 2006. These legacy contract provisions correctly recognize that some covered entities that supply electricity or steam under long-term contracts will not be able to pass through the cost of purchasing emissions allowances to their customers.

As set forth in Section 95870(g)(2), the proposed regulation allocates allowances to legacy contract generators with an industrial counterparty covered by the Cap-and-Trade Regulation for the term of the contract. We understand that the reference to the allocation of allowances to legacy contract generators with an industrial counterparty "through the second compliance period" in Section 95890(e) was inadvertent, and that CARB intends to revise Section 95890(e) to make clear that such generators will receive allowances for the term of the contract. We urge CARB to correct this error promptly, and we thank CARB staff for their prompt attention to this issue. (LIQUIDE

Response: ARB staff acknowledges the need to accurately reflect its intent that allowance allocation to a legacy contract generator with an industrial counterparty will continue through the end of the legacy contract. The intent, as correctly noted in the other relevant sections of the regulation, and particularly within the equations contained in section 95894, is to allocate through the term of the contact for these generators. The clarification to make to section 95890(e) consistent with other provisions and staff's intent will be made within a future rulemaking.

Allowance Allocation to Legacy Contract Generators with an Industrial Counterparty

B-2.4. Multiple Comments: The Staffs proposed amendments (specifically, Section 95891(f)) would penalize an industrial entity receiving a direct allocation of free allowances under Section 95891(d), if the industrial entity has a "direct corporate association" with an entity that is a counterparty to a "Legacy Contract." Pursuant to Section 95891(f), free allowances that otherwise would be allocated to an industrial entity under Section 95891(d) would be taken from the industrial entity based on its direct corporate association with a Legacy Contract Counterparty, even when the industrial entity has no contractual relationship with the Legacy Contract Generator, and no influence over that Legacy Contract.

Shell - Martinez Refinery and Shell Energy North America (US) L.P. ("Shell Energy") share a "direct corporate association." Shell Energy is a party to a Legacy Contract, but Shell- Martinez Refinery has no contractual relationship with either Shell Energy or the Legacy Generator with respect to this contract. The effect of the proposed amendment would remove free allowances allocated to the refinery as an entity of the "trade exposed' industry sector, and provide those free allowances to the legacy contract generator to cover their compliance obligation. But for the fact that Shell Martinez Refinery and Shell Energy are deemed to have a "direct corporate association," the refinery would not be obligated to relinquish free allowances they have been given as part of the "trade-exposed" sector, and these free allowances would be provided to the legacy contract generator by ARB.

The interplay of these proposed regulations has the unintended consequence of disadvantaging Shell - Martinez Refinery in relation to other refineries within the refining sector. Furthermore, introduction of these regulatory changes impacts the refinery's long term GHG emissions reduction strategy. Lastly, removing free allowances that ARB has allocated to a 'trade exposed" entity, and then providing those allowances to a legacy contract generator that the refining entity has no contractual relationship also raises potential legal questions.

The ARB should modify or eliminate Section 95891(f) to remove the inconsistent treatment and impact on the Shell Martinez Refinery. In a highly competitive refined products market, the potential disadvantage to the Refinery as a result of this proposed rule is significant. (SHELL 2)

Comment: The Staff's proposed amendments (specifically, Section 95891(f)) would have the effect of penalizing an entity that is a counterparty to a Legacy Contract if the Legacy Contract Counterparty has a "direct corporate association" (within the meaning of Section 95833(a)(2)) with an industrial entity receiving a direct allocation of free allowances under Section 95891(d). Pursuant to Section 95891(f), free allowances that otherwise would be allocated to an industrial entity under Section 95891(d) would be taken from the industrial entity based on its direct corporate association with a Legacy Contract Counterparty.

The Staff's proposed amendments would place Shell Energy -- a Legacy Contract Counterparty -- at a disadvantage compared to other equally situated entities. All other Legacy Contract counterparties that do not have an association with an Industrial Entity receive free allowances as "transition assistance." As a separate matter, the Staff's proposed amendments have the unintended consequence of eliminating any incentive for a Legacy Contract generator to renegotiate the terms of the Legacy Contract.

Shell Energy has a "direct corporate association" with Shell Oil Company, the owner of the Martinez Refinery and an "Industrial Entity" under the regulations. The Martinez Refinery is eligible for a direct allocation of allowances as "transition assistance" pursuant to Section 95891(b) or (d). However, under proposed Section 95891(f), the Martinez Refinery would have its allocation adjusted (reduced), owing to its direct corporate association with Shell Energy, a Legacy Contract Counterparty. This proposed approach would unfairly disadvantage Shell Energy under its Legacy Contract.

The Staff's proposed amendments also would have the unintended consequence of discouraging a Legacy Contract generator from attempting to renegotiate a Legacy Contract with a counterparty that is associated with an industrial entity. When these proposed amendments were published, the generator that is a party to Shell Energy's Legacy Contract ceased efforts to renegotiate the Legacy Contract. The proposed amendments eliminated the incentive for the generator to engage in efforts to mutually agree on the allocation of GHG compliance costs arising under the Legacy Contract (under which the generator is the obligated entity). In effect, the Staff's proposed amendments, if adopted, would pre-determine the "winner" as between the generator and its counterparty regarding the allocation of GHG compliance costs under the Legacy Contract.

All Legacy Contract counterparties should be treated equally with respect to the allocation of free allowances associated with emissions from the generation facilities under contract. Section 95894 of the proposed regulations properly provides for a direct allocation of free allowances to eligible Legacy Contract counterparties for "transition assistance." Section 95891(f) of the proposed regulations, however, has the effect of subtracting these allowances from the allocation of allowances to an Industrial Entity that is not a Legacy Contract Counterparty, but that has a direct corporate association with a Legacy Contract Counterparty. Section 95891(f) should be eliminated. A Legacy Contract Counterparty's eligibility for allocation of free allowances for transition assistance should stand on its own merits, without adjustment based on a "direct corporate association." (SHELL 3)

Comment: In response to Board direction to address legacy contracts, staff has proposed language that negatively impacts Shell. The Shell Refinery and Shell Energy North America share a direct corporate association. Shell Energy is a party to legacy contract, but the refinery has no contractual relationship with respect to this contract. The effect of the proposed amendments would remove free allowances allocated to the refinery as part of a trade-exposed sector and provide that to the contract generator to cover their compliance obligation. But for the fact that the refinery and Shell Energy have a direct corporate association, the refinery would not be required to provide these allowances to the contract generator. Staff has indicated that this requirement provides the necessary incentive for the legacy contract parties to re-negotiate the contract. We do not believe this is true, and in the case, actually provides a disincentive for the party receiving the free allowances to renegotiate. We continue to want to work with staff in this regard. Thank you. (SHELL 4)

Comment: We've been actively attempting to renegotiate that contract. As we noted in our written comments as well the comments that Teresa Makarewicz made earlier, we believe there is a provision in the language that is currently discriminatory to the Shell contract specifically. And the reason that I say that is that generators that are similarly situated are receiving transition assistance in the form of free allowances from the market. And in this case, the language takes allowances from the refinery from Martinez, who is our affiliate, and gives those allowances to the generator under our contract. Martinez is not a party to the contract. They don't have any operational control or dispatch ability over the generator. And so we would urge you to try to fix this discriminatory language either through some sort of regulatory guidance or other means in order to create a level playing field. In the meantime, we plan to continue to try to renegotiate the contract with our counterparty. That is the ultimate goal for us and, we will continue to work with staff on this it as well. (SHELL 5)

> **Response:** Treating entities that have a direct corporate association as one unit is consistent with the treatment of direct corporate associations elsewhere in the regulation. For instance, entities with direct corporate associations must share auction purchase limits and compliance instrument holding limits with each other. ARB staff does not agree that the transfer of allowances from a counterparty that has a direct corporate association with an industrial entity to the legacy contract generator disadvantages the industrial entity. Presently, the industrial counterparty corporation does not incur the indirect carbon cost through the legacy contract. Because they sell the electricity in a market that includes the compliance cost, they are able to make a profit relative to their competitors. The transfer of allowances from the industrial counterparty corporation to the legacy contract generator will allow the industrial counterparty corporation to internalize the carbon cost.
>
> Staff does not agree the allocation of allowances to a legacy contract generator with an industrial counterparty removes the incentive to renegotiate the legacy contract. The legacy contract generator with an industrial counterparty must request legacy contract allocation each year, and in that request must attest under penalty of perjury that they have made a good faith effort to renegotiate the contract, but that they were unable to renegotiate the legacy contract with the counterparty to address recovery of the costs of compliance. If the legacy contract generator with an industrial counterparty does not make a good faith effort to renegotiate the contract, they will not be eligible for allowance allocation.

Eligibility Requirements

B-2.5. Comment: Sections 95802 and 95894. Generators That Have Already Bargained for Costs Associated with GHG Regulation Should Not Qualify for Transition Assistance. The proposed amendments inappropriately provide a free allocation of allowances to generators that: (1) had notice of the potential for future greenhouse gas (GHG) costs; and (2) bargained for the costs associated with cap-and-trade compliance in their contracts. PG&E therefore opposes ARB's proposed "legacy contract" definition to the extent that it provides a windfall generators have already been and continue to be compensated by PG&E customers. PG&E continues to propose simple revisions to the definition of "legacy contract" to ensure that generators that were aware of and agreed to assume responsibility for GHG compliance costs bear those costs.

1. Legacy Contract Definition Should be Revised to Prevent Windfalls to Generators Aware of GHG Costs

ARB should amend the date before which an executed contract qualifies as a legacy contract from September 2006 to August 15, 2005.[230] The basis for the use of August 15, 2005, is also consistent with CPUC decisions interpreting whether generators foresaw the imposition of a carbon price in the electric sector. In fact, potential governmental action imposing GHG compliance costs on fossil fuel power plants in California was foreseeable *prior to* August 15, 2005.[231]

IOU counterparties and, presumably other generators, are sophisticated commercial parties with experienced commercial, regulatory, and legal teams aware of the potential for GHG costs prior to the actual date of passage of AB 32. To the extent the parties to the contract cannot either agree as to whether the generator knowingly assumed GHG compliance cost risk at the time the contract was executed or renegotiate their contract to further address GHG costs, the matter can be resolved by a court or arbitrator in a dispute resolution proceeding. Where a court or arbitration decision has found that GHG compliance costs are the responsibility of the generator, ARB simply should not provide free allowances to the generator.

> **Recommendation:** PG&E therefore recommends the following changes to the definition of a “Legacy Contract” laid out in Section 95802:
>
> (~~195~~197)“Legacy Contract” means a written contract or tolling agreement, originally executed prior to ~~**September 1, 2006**~~**August 15, 2005**, governing the sale of electricity and/or Legacy Contract Qualified Thermal Output at a price, determined by either a fixed price or price formula, that does not provide for recovery of the costs associated with compliance with this regulation; the originally executed contract or agreement must have remained in effect and must not have been amended since ~~**September 1, 2006**~~**execution** to change or affect the terms governing the California greenhouse gas emissions responsibility, price or amount of electricity or Legacy Contract Qualified Thermal Output sold, or the expiration date. For purposes of this regulation, legacy contracts exclude contracts that ~~**have been amended to include**~~ ~~**gave rise to**~~ **are eligible to execute** a Legacy PPA Amendment, as defined in the Combined Heat and Power Program Settlement Agreement Term Sheet pursuant to CPUC Decision ~~number D-~~10- 12-035, with a privately owned utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU). ~~For the purpose of this regulation, Legacy Contracts include contracts that are considered non-standard QF contracts.~~ This definition

[230] 1 D. 12-12-002 (citing August 15, 2005 as the date a firm cap on GHG emissions was introduced by the Legislature) available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M041/K695/41695122.PDF D.12-04-046 stated contracts negotiated and executed when AB 32 was working its way through the legislature should have taken the potential impacts of AB 32 into consideration. Even those negotiating contracts shortly before then might also have reasonably foreseen that this issue could arise. D.12-04-046, page 61available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/164799.PDF

[231] For example, in 2004, the CPUC proposed a GHG Cap-and-Trade Program in an Order Instituting Rulemaking (OIR) and, in its comments on the OIR, the Independent Energy Producers Association mentioned independent generators internalizing the costs of GHG emissions reductions in offers submitted into the utility procurement processes. AB 32 was introduced into the California Legislature in December 2004. In June 2005, GHG emissions reduction targets were established for California by the Executive Order S-3-05.

of a "Legacy Contract" does not apply to opt-in covered entities. **For purposes of this regulation, Legacy Contracts also exclude contracts as to which acourt or arbitrator(s) in a dispute resolution proceeding between the parties to the agreement finds that, at the time the agreement was executed, the seller understood that if there were a future change in the law that imposed a cost on the facility because of its greenhouse gas emissions, the seller would be responsible for paying that cost. (**PGE 4)

Response: Please see response number B-6.7 to 45-day comments.

B-2.6. Comment: 2. The Renegotiation Provision Should Be Reinstated The removal of provision 95891(f)(4), would provide free allowances to any legacy contract generator even if the contract is renegotiated to include consideration of GHG costs following ARB's approval of a legacy contract generators' allowances for a particular budget year. This section should be reinstated to ensure legacy contract generators are not provided a windfall under the cap-and-trade program.

Recommendation: In addition, Section 95894(a)(5) could be modified as follows:

If, subsequent to the submittal of the foregoing information and supporting documentation, there is any material change in the information and statements provided to the Executive Officer, the party who submitted such information and statements shall submit a supplemental attestation and supporting materials addressing any such material change to the Executive Officer within 30 days after the change occurs. **If the Executive Officer receives information demonstrating that the Legacy Contract was renegotiated to include consideration of greenhouse gas costs, the Executive Officer shall prorate any allocation to include only emissions prior to the date of renegotiation.** (PGE 4)

Response: ARB staff does not agree with the commenter and declines to make the suggested edits. Allowing a legacy contract generator to retain allowances if the contract is renegotiated can serve to assist in the renegotiation process—e.g., the legacy contract generator could use those allowances or their associated value to support the negotiation processes by offering the allowances to the counterparty.

Duration of Allowance Allocation

B-2.7. Comment: 3. Transition Assistance Should Be Limited to Compliance Period 1

Extending legacy contract transition assistance through 2017 removes any incentive for generators to agree to contract negotiations until 2017, and prolongs the windfall for generators that have already been and continue to be compensated by PG&E customers.

Recommendation: PG&E urges ARB to limit the transition assistance to 2013 and 2014 and therefore recommends the following conforming regulatory changes:

95870 (g) Allowances will be allocated to legacy contract generators for budget years 2013 ~~and~~ through 201~~4~~4~~7~~ for transition assistance. The Executive Office will transfer allowance allocations into each eligible generator' s limited ex emption holding account by October ~~15~~24, 2014 for eligible Legacy Contract Emissions pursuant to the methodology set forth in section 95894, and by October 24th of **~~each subsequent year~~ 2015 for the 2014 compliance year.**

95891(a) Opt-in covered entities are not eligible for transition assistance due to legacy contract emissions. To be eligible to receive a direct allocation of allowances under this section, the primary or alternate account representative of a legacy contract generator shall submit the following in writing via certified mail to the Executive Officer by June 30, 2014 or within 30 days of the effective date of this regulation for allocation in 2014, whichever is later, and by June 30th of **~~2015each subsequent year~~** when applicable (PGE 4)

Response: Staff weighed the advantages and disadvantages of extending transition assistance for legacy contract generators without an industrial counterparty through 2017, and decided that it did not want to place an undue uncertainty on California's electricity system, which could occur if transition assistance were not extended and a generator may have to shut down because it could not afford the costs of compliance with this regulation. Staff chose to extend transition assistance to cover some of the cost of compliance for peaker plants that could be called upon while California puts a plan in place to address the continuing drought and the closing of the San Onofre power plant.

Staff asserts that there is still incentive to renegotiate these contracts before the end of 2017 because of an annual requirement to attest under penalty of perjury that the entity has made a good faith effort to renegotiate the contract, but that they were unable to renegotiate the legacy contract with the counterparty to address recovery of the costs of compliance. If the legacy contract generator does not make a good faith effort to renegotiate the contract, they will not be eligible for allowance allocation.

Emissions Covered under Legacy Contract Transition Assistance

B-2.8. Comment: 4. ARB Should Partially Allocate Allowances to Legacy Contract CHP Facilities with PPAs Addressing Generation-Emissions. Some of the generators eligible for a Legacy Contract allocation are CHP facilities with thermal host contracts that do not address GHG compliance costs. However, these generators may be compensated for GHG costs associated with electricity sales through power purchase agreements (PPAs) with separate entities. Should a CHP legacy contract generator require transition assistance for their thermal sales and is compensated for GHG costs associated with electric sales, ARB should not provide the entity with an allocation associated with the electricity contract. To do so would be a windfall where generators are already compensated for GHG costs associated with its electricity sales. Accordingly, where applicable, ARB should implement 95894(c) of the proposed amendments to provide this category of generators with zero allowances associated with an entity's electricity sales. This methodology would appropriately provide a facility allowances associated with its thermal sales for which it is not compensated, and not provide allowances associated with its PPA where GHG costs are addressed. (PGE 4)

> **Response:** The current regulatory provisions allow for staff to provide allocation only for those emissions covered under a legacy contract. The MRR requirements for reporting emissions from a cogeneration facility will allow staff to determine the emissions associated with thermal sales and the emissions associated with electricity sales. The transition assistance is only for the portion of emissions that do not have a cost pass through mechanism due to the legacy contract.

Base Year for Determination of Allocation Amount

B-2.9. Comment: d. Basis for Transition Relief. Section 95894(d)(1) provides the numerical methodology for providing the Legacy Contract transition relief for a total of five years. This methodology provides an administratively convenient process, but will not account for actual legacy contract emissions. The PEC facility has a tolling agreement, and its dispatch is completely controlled by its legacy contract counterparty. In 2012, PEC's run time was only 20% (approximately) of its permitted capacity. Therefore, due to circumstances wholly beyond PEC's control, including drought-induced reduction in available hydropower, PEC's facility could be dispatched at a significantly higher level in the coming years, yet PEC's transition relief would be based on its 2012 dispatch levels. The final amendments leave the legacy contract holders exposed to this additional increase in dispatch without a corresponding increase in transition assistance. PEC would recommend that this methodology be revisited if future transition relief is considered in a subsequent rulemaking so as to more accurately reflect ongoing emission levels. (PANOCHE 2)

> **Response:** ARB staff determined that the 2012 data year was the most appropriate year on which to base transition assistance because these data are the most recent verified data that could be used to determine legacy contract allowance allocation. Further, staff determined that this data set would be used for every year generators without industrial counterparties request transition assistance. Using a consistent data year, rather than the actual emissions/thermal output/electricity generation, provides incentive for the legacy contract generator to renegotiate the legacy contract. If ARB staff updated allocation based on actual emissions/output/generation every year, there would

be no incentive for the legacy contract generator to renegotiate the contract with the purchaser of the steam and or electricity.

B-3. Natural Gas Suppliers

General Support for Allowance Allocation to Natural Gas Suppliers

B-3.1 Multiple Comments: Section 95893. PG&E Supports Natural Gas Allowance Allocation to Natural Gas Suppliers on Behalf of their Customers, to Gradually Introduce the Cost of Carbon Into Natural Gas Bills

PG&E strongly supports the addition of Section 95893, which provides a fair allocation to natural gas suppliers, on behalf of their customers, with a balanced approach to the consignment of allocated allowances. The proposed allocation also establishes a framework for supporting the emissions reduction goals of AB 32. In addition, PG&E supports staff's proposal to use 2011 as the baseline year for the initial allocation of allowances. We truly appreciate ARB staff's extensive effort in working through technical issues related to the 2011 baseline year.

Section 95893(b)(1)(A) of the proposed amendments sets a consignment requirement for all natural gas suppliers while offering utilities the discretion to consign additional allowances, if needed for an entity's overall compliance strategy. The levels of consignment in the proposed regulation were designed to provide a balanced transition through 2020, mitigating market risk and reducing potential cost to customers. PG&E appreciates the time and effort the ARB put into the consideration and analysis for the proposed level of consignments through 2020. (PGE 4)

Comment: First, SoCal Gas and SDG&E strongly support the allocation of allowances to natural gas suppliers for the protection of natural gas ratepayers. The proposed methodology allocates allowances to suppliers for most of their emission and requires supplies to consign a portion of those allowances to the auction. The revenue generated from the consigned allowances is required to be used on behalf of the rate payers.

In 2015, suppliers will be required to consign 25 percent of our allowances to auction, with the amount consigned increasing at five percent a year. The required percentages are stated in Table 9.4 of your materials. (SCGE 2)

Response: Thank you for the support.

Allocation for Natural Gas Supplied to "But For" Cogeneration Facilities

B-3.2 Multiple Comments: Section 95851(c) "But for" CHP. This proposed modification extends the limited exemption of emissions for qualified thermal output through the third compliance period and moves the compliance obligation for these emissions to the natural gas supplier.

SDG&E and SoCalGas are concerned that the proposed amendment package does not allocate an incremental quantity of allowances to natural gas suppliers to cover this additional compliance obligation, as the record from the October 25, 2013 Board meeting reflects a commitment from staff to propose an additional allocation to the natural gas utility.

We request that ARB act on this commitment to provide natural gas suppliers with allowances for the “but for” CHP facilities, and clearly describe how the allocation is to be calculated and deposited into natural gas suppliers’ accounts.

> (c) Operators of cogeneration facilities and district heating facilities that have been approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j), that meet or exceed the annual threshold in section 95812~~(d)~~(c) will have ~~a~~no compliance obligation and are not covered entities ~~beginning with the second~~during the first, second, and third compliance periods. The compliance obligation during the second and third compliance periods for these exempt facilities will be held by the upstream natural gas supplier. Facilities that are not approved by the Executive Officer for a limited exemption of emissions will have a compliance obligation. The 2011 baseline allocation for natural gas utilities will be adjusted to include the emissions of approved facilities beginning in 2015. (SEMPRA 4)

Comment: Section 95851(c). ARB Should Provide Natural Gas Suppliers an Allocation to Cover Emissions from “But for” CHP Facilities. PG&E neither supports nor opposes changes to the proposed limited exemption for cogeneration facilities and district heating facilities clarifying that the natural gas supplier becomes the point of compliance for second and third compliance period emissions. However, PG&E is very concerned that the proposed amendment package does not allocate an incremental amount of allowances to natural gas suppliers to cover this additional compliance obligation. The record from the October 25, 2013 Board meeting reflects the following comments from staff on this issue: “What we've actually proposed in this attachment . . . to the Resolution this morning is that we would exempt but-for going forward. So they won't be a covered entity. In that vein, I don't think there is a need for transition assistance. You heard PG&E mention they saw this late. It essentially pushes the obligation upstream to the natural gas utility. And we have a proposal for allocation to the natural gas utility. I think that that should cover the issue with the but-for CHP.”

ARB should act on this commitment to provide natural gas suppliers with allowances to cover “but for” CHP facilities’ emissions, and clearly describe how the allocation is to be calculated and deposited into natural gas suppliers’ accounts. Customers of natural gas suppliers should not be required to subsidize “but for” CHP facilities by requiring these customers to procure allowances to cover these facilities’ emissions. If ARB’s intention is to provide an incentive to support “but for” CHP facilities, ARB should provide the allocation staff represented would be provided.

PG&E urges the ARB to honor its commitment to provide allowances associated with “but for” CHP facilities to natural gas suppliers. To assist natural gas suppliers in planning for the increased compliance obligation imposed by the “but for” CHP facilities, PG&E requests the ARB include clarifying provisions in the Regulation to establish the process by which exempt facilities and their applicable emissions are identified. Specifically, PG&E requests that the regulation clarify:

- o How and when the eligible "but for" CHP facilities will be identified to the natural gas utilities by ARB; and
- o The process by which the ARB is to inform a natural gas utility of the increase in its emissions compliance obligation associated with these "but for" facilities.

PG&E also notes that natural gas suppliers are not subject to a compliance obligation until the second compliance period. The proposed amendments should clarify that the natural gas distribution utility is not responsible for "but for" facility emissions applicable to the first compliance period.

Recommendation: PG&E suggests the following revisions to Section 95851:

(c) Operators of cogeneration facilities and district heating facilities that have been approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j), that meet or exceed the annual threshold in section 95812~~(d)~~(c) and have not executed a power purchase agreement pursuant to the Combined Heat and Power Program Settlement Agreement approved by CPUC Decision 10-12-035 with a privately owned utility as defined in the Public Utilities Code section 216 will have ~~a~~no compliance obligation and are not covered entities ~~beginning with the second~~during the first, second, and third compliance periods. The compliance obligation during the second and third compliance periods for these exempt facilities will be held by the upstream natural gas supplier. Facilities that are not approved by the Executive Officer for a limited exemption of emissions will have a compliance obligation. The Executive Officer shall inform the upstream natural gas supplier of those facilities approved for an emission exemption pursuant to this Section 95852 (j) by no later than January 1, 2015. The Executive Officer shall provide the natural gas supplier with all verified emissions applicable to the exempt facilities attributable to the preceding budget year for which the natural gas supplier has a compliance obligation by no later than October 1, 2016 and each year thereafter. (PGE 4)

Comment: First, I'd like to reiterate what was said at the October Board hearing regarding the transition of but-for CHP compliance upstream to the natural gas supplier. We were surprised to learn of this for the first time at the hearing, but appreciated staff's acknowledgement that additional allocation would be provided to cover this obligation. However, language to provide this assistance was unintentionally omitted from the amendment package before you today. But we understand that staff intends to remedy this issue when the regulation is reopened to incorporate the rice cultivation protocol. And we look forward to working with staff to finalize the allocation methodology. (PGE 5)

Comment: Second, the proposed modification relating to CHP in Section 95851(C) extends the limited exemption emissions for qualified final output through the third compliance period and moves the compliance obligation for these emissions to the natural gas supplier. As was stated earlier, we're concerned that there were allowances that were discussed in October that were not provided for, but we also understand will be part of the true-up process as you move forward. (SCGE 2)

> **Response:** The commenters are concerned that ARB might not allocate allowances to natural gas suppliers to cover the emissions from cogeneration facilities that have been approved for the limited exemption for emissions from qualified thermal output, loosely referred to as “but for” facilities. The 15-day modifications extended the exemption, which originally was proposed only for the first compliance period, through the second and third compliance periods. As stated by ARB staff at the October 25, 2013 Board meeting, “but for” facilities that have been approved for a limited exemption of emissions from qualified thermal output are not covered entities, pursuant to section 95852(j) as modified. Because they are not covered entities, natural gas utilities will have the compliance obligation for gas delivered to these facilities.
>
> During the second and third compliance periods, natural gas suppliers will have compliance obligations for and receive allocations based on the amount of natural gas they supplied to end users in 2011 that are not covered entities. This amount of natural gas will include natural gas supplied to “but for” facilities since they are not covered entities. Natural gas suppliers do not have a compliance obligation during the first compliance period. Because the regulation is clear on these points, it is not necessary to make the modifications requested by the commenters.
>
> Each natural gas supplier’s allocation is based on its emissions in 2011.“But for” CHP facilities will not be considered covered entities so their emissions would be part of the 2011 compliance obligation and subsequent allowance allocation. If a “but for” CHP facility’s emissions increase, rendering it ineligible for a limited exemption, then its emissions would be removed from the natural gas supplier’s 2011 compliance obligation calculation that feeds into the annual allocation

General Comments

B-3.3. Comment: SDG&E and SoCalGas strongly support the allocation of allowances to natural gas suppliers for the protection of natural gas ratepayers. The proposed methodology allocates allowances to suppliers for most of their emissions and requires suppliers to consign a portion of these allowances to the auction. The revenue generated from the consigned allowances is required to be used on behalf of the rate payers. In 2015, suppliers would be required to consign 25 percent of their allowances to auction, with the amount consigned increasing at five percent a year. The required consignment percentages are stated in Table 9.4.

In section 95894(b)(1)(A), which pertains to the transfer of allowances to natural gas supplier accounts, there is language that can be used to define the consignment percentages in Table 9.4 as minimum percentages. Our understanding is that the intent of the regulation was to establish limited consignment at 25% graduated by 5% per year to 50% by 2020. As such, we request that ARB clarify their intention that the required consignment percentages in Table 9.4 are as stated and that, at an appropriate time, the following changes be made to the regulation.

(b) Transfer to Natural Gas Supplier Accounts
(1) When a natural gas supplier as defined in section 95811(c) is eligible for a direct allocation, it shall inform the Executive Officer <u>will allocate on on October 24, or the first business day thereafter, of each calendar year from 2015-2020, annual allowance budgets into the natural gas supplier's compliance account, minus the quantity placed into the Limited Use Holding Account.</u> By September 1, or the first business day thereafter of the amount of allowances to be placed into its Compliance and Limited Use Holding Account with the following constraints. If an entity fails to submit its distribution preference by this deadline, ARB will automatically place all directly allocated allowances for the following budget year in the entity's Limited Use Holding Account:
(A) The quantity of allowances placed into the Limited Use Holding Account will equal at least the amount of allowances provided in section 95893(a) multiplied by the applicable percentage in Table 9-4, rounded down to the nearest whole allowance. (SEMPRA 4)

> **Response:** ARB staff presumes the commenters are referring to section 95893(b)(1), which addresses natural gas supplier allocation. Section 95894 addresses legacy contract generators. Staff believes the existing language is sufficiently clear regarding the requirement to consign at least as many allowances as specified by Section 95893(b)(1)(A), and does not see a need for further clarification. By making the consignment amount requirement for "at least," ARB staff wanted to recognize that some natural gas suppliers may want to consign more than the limit prescribed in the regulation. It was not staff's expectation or intent for more than the minimum to be consigned each year.

B-3.4. Comment: The proposed amendments require each natural gas supplier to nominate the number of allowances that ARB should deposit in its limited use holding account and compliance account by September 1, 2014. If a natural gas supplier does not state a preference by this date, all allocated allowances will be placed in the limited use holding account for consignment. PG&E does not oppose this general nomination structure. However, for the purposes of the 2015 budget year allocation, this early deadline could prove problematic.

Specifically, the CPUC has opened an Order Instituting Rulemaking (OIR) to address natural gas distribution utility cost and revenue issues associated with the Cap-and-Trade Program. The CPUC indicated its interest in directing the utilities to consign allowances above the minimum requirement indicated in Section 95893(b)(1)(A). However, the CPUC has yet to establish a procedural schedule to suggest when the natural gas consignment issue would be resolved. Accordingly, PG&E requests that natural gas utilities be provided with flexibility concerning the nomination date applicable to the 2015 budget year and recommends the following changes to Section 95893(b): (1) For budget year 2015, when a natural gas supplier as defined in section 95811(c) is eligible for a direct allocation, it shall inform the Executive Officer by 10 days following the issuance of a final CPUC Decision or Order establishing the percentage of natural gas allowances allocated for the purposes of ratepayer protection of the amount of allowances to be placed into its Compliance and Limited Use Holding Account. For budget years 2016 and thereafter, when a natural gas supplier as defined in section 95811(c) is eligible for a direct allocation, it shall inform the Executive Officer by September 1, or the first business day thereafter of the amount of allowances to be placed into its Compliance and Limited Use Holding Account with the following constraints. If an entity fails to submit its distribution preference by this deadline, ARB will automatically place all directly allocated allowances for the following budget year in the entity's Limited Use Holding Account. (PGE 4)

> **Response:** ARB staff believes the existing language provides sufficient time for natural gas suppliers to inform ARB of how many allowances to place in which of their accounts. As the commenter noted, the CPUC has already opened an OIR to address related issues, including how many allowances are to be consigned. Participants in this procedure have indicated a desire to complete the rulemaking prior to September and proposed timelines which would accomplish this. The Cap-and-Trade Regulation, section 95893(b), specifies a fallback plan of all allowances going into the Limited Use Holding Account in case natural gas suppliers cannot or do not specify the amounts to be placed in their Compliance Accounts. Staff believes that this effectively covers all situations. ARB staff cannot postpone the deadline for this information until an uncertain date because ARB staff needs to know, prior to each auction, how many allowances it will be selling at that auction. By making the consignment amount requirement for "at least," ARB staff wanted to recognize that some natural gas suppliers may want to consign more than the limit prescribed in the regulation. It was not staff's expectation or intent for more than the minimum to be consigned each year.

B-4. Other Product Based Benchmarks

Tissue Benchmark

B-4.1. Multiple Comments: During the two-and-half years since the California Air Resources Board ("CARB") first proposed product- based GHG emission benchmarks, CARB has proposed or adopted five different benchmarks for the tissue sector. Just two months before announcing the proposal now before the Board, CARB informed companies with tissue facilities in California that the benchmark now on the books was incorrect and a different one would apply. While CARB has flip-flopped many times in the last two years, the proposed benchmark on which it has now landed is perhaps the most needlessly complicated and scientifically unsupportable of them all. We address these problems in detail below, but first highlight the major flaws.

1. The proposed tissue benchmark departs from CARB's principles for product-based benchmarks and plainly favors one facility over another. CARB has provided no adequate scientific explanation for the proposed benchmark; the explanation it has provided is contradictory.

The tissue benchmark now in the Regulation was developed using CARB's "Best-in-Class" principle, though in January of this year CARB announced that the correct benchmark was one based on its "90% of Average" principle. These are CARB's two alternative principles for developing product benchmarks, and both are based on tonnage (i.e., GHG emissions intensity expressed in terms of average tons of products produced). See Appendix B to July 2011Proposed Cap and-Trade Regulation at 3. CARB now proposes to adjust the benchmark for water absorbency. Adjusting for water absorbency unquestionably favors the more GHG emissions-intensive through-air drying ("TAD") technology over conventional tissue technology, which is more efficient in terms of both energy and GHG emissions. There are only two tissue facilities in the State; one uses TAD technology and the other utilizes conventional technology. The proposed benchmark is discriminatory, and as such is inconsistent with the statute.

In an email to K-C dated March 11, 2014, CARB staff justified the use of this water absorbency adjustment by quoting the statement in Appendix C to the 2013 proposed amendments to the Regulation: "While it is true that the two facilities use different technologies to produce different types of tissue products with different qualities, staff believes that the functionality of the product is still the same: to absorb water." However, in the very next paragraph, CARB staff stated, "After conferring with the representatives from your company, staff agrees that different tissue products focus on different functionality: facial tissue focuses more on softness, bathroom tissue is the balance of softness, strength and absorbency, and paper towels focuses more on absorbency and strength." (Emphasis added.) Thus, CARB itself acknowledges that bath tissue's functionality cannot be measured by water absorbency alone, and thus its own justification for adding the discriminatory water absorbency adjustment to the bath tissue benchmark makes no sense.

Note also that CARB's recognition that the function of bath tissue is "the balance of softness, strength and absorbency" is consistent with both common sense and K-C's consumer research. Wikipedia defines toilet paper as "a soft tissue paper product primarily used for the cleaning of the anus to remove fecal material after defecation or to remove remaining droplets of urine from the genitals after urination, and acts as a layer of protection for the hands during this process." This definition is consistent with K-C consumer research indicating that users typically choose to use a quantity of toilet paper based on their judgment of "substance-in-hand." In other words, the amount perceived adequate to do the cleaning task required, while also protecting their hand from contamination. Clearly, there are factors other than water absorbency capacity controlling usage behavior and consumption. In light of this, the proposed benchmark's departure from CARB's stated principles for developing product benchmarks in favor of a discriminatory benchmark that favors the facility with higher GHG emissions intensity is without justification and at odds with AB 32.

2. CARB cannot demonstrate that absorbent capacity is related to tissue utility in such a way that it is a superior metric than CARB's stated tonnage-based principles for product benchmarks.

In order to justify a change from the traditional GHG per ton metric, the replacement metric must relate to the utility (i.e., the quantity used based on functionality) of the product better than the traditional metric. There is insufficient basis to justify CARB's selection of absorbent capacity as the sole predictor of utility/consumption for this product.

P&G apparently has persuaded CARB that lower density tissue products made using the more emissions- intensive TAD technology should be credited for their higher absorbent capacity. CARB has arbitrarily chosen to value the entire volume of the absorbent capacity in the product by testing samples as if this entire capacity was actually used by the consumer. This decision results in a benchmark much higher than can be justified by the actual mass of fiber in the tissue sheet. In addition, adjusting for water absorbency necessarily raises the benchmark and thus allows for greater GHG emissions, which is at odds with AB 32's purpose of reducing emissions. For example, if the water absorbency capacity adjustment were set at ten, then the benchmark would be set at ten times what it would be if based on tonnage alone. It is not at all clear that the actual consumption of a bath tissue product is inversely proportional to its absorbent capacity, as implied by the proposed correction factor, and CARB has provided no evidence to support that the extreme value given to absorbent capacity in the proposed benchmark.

3. There is no reasonable basis for CARB to segregate the emissions data, and in so doing, to determine the individual benchmark value for each type of tissue (facial tissue, delicate task wipers, paper towel and bath tissue).

The proposed benchmarks for the different categories of tissue are based on the erroneous assumption that the amount of GHG emissions per ton of finished product is the same for each type of tissue at each facility. For example, the emission per ton value that CARB determined for facial tissue and delicate task wipers, products manufactured by K-C, is the same (1.32 per ton). In fact, however, K-C knows that based on production rates the emissions value per ton for facial tissue is significantly higher than for delicate task wipers and bath tissue. While daily emissions of GHG from its facility are nearly the same over time, approximately 33% more delicate task wipers tonnage or 51% more bath tissue tonnage can be produced per day as compared to facial tissue. CARB, having only collected total facility emissions, lacks the data required to accurately calculate the difference; and K-C does not have the necessary metering capability on each tissue machine required to accurately report the emissions associated with each type of tissue product. In short, CARB lacks the data required to justify the proposed benchmarks, and the data required to develop these benchmarks is not currently available.

4. The addition of the water absorbency adjustment to the bath tissue benchmark and not the other three types of tissue appears to be based solely on the fact that at present only bath tissue is produced by both of the facilities in the state. It is inappropriate to base a benchmark based on the range of tissue products manufactured by the two facilities, as a facility's product mix may change.

CARB utilizes the Best-in-Class principle for all four product types but adds the water absorbency adjustment only to bath tissue. In its March 11, 2014 email, CARB staff explained that this was because, "While facial tissue, paper towel and wipers are manufactured only by one company, bathroom tissue is produced by 2 companies." This begs the question: if one company were to change its product mix, such that both also produced one of the other tissue product types, would CARB amend the Regulation to add the water absorbency adjustment to that other tissue product benchmark? Would it do so on an annual basis as these companies adjust their product mix from year-to-year? Or even month-to-month? This is clearly an inappropriate basis upon which to base a GHG emissions product benchmark.

We are concerned that CARB's intent with this most recent proposal is to arbitrarily balance the incremental cost that each of the two remaining tissue manufacturing facilities in California will incur either to reduce GHG emissions through manufacturing process changes or to purchase allowances to cover their respective obligations. There is significant risk that these incremental costs could cause either company to shift the manufacture of tissue products outside the state. P&G's facility utilizes tissue manufacturing technology that has a significantly higher GHG emissions intensity than K-C's facility. P&G's facility also has more than five times the tissue production output as the K-C facility. The first benchmark for tissue that CARB adopted in 2011(and is still on the books, though CARB announced in January that it had been calculated incorrectly) was based on the Best-in-Class principle, which was K- C's facility, and P&G's facility faced a significantly higher compliance cost because of its higher GHG emissions intensity (as well as its larger production).

By incorporating water absorbency capacity as a principle factor for the shared bath tissue products, CARB favors the TAD technology used by P&G, as it manufactures tissue sheets with more void space. Assigning a disproportionate and excessive value to absorbent capacity further skews the benefit to P&G over K-C. In short, CARB's current proposal shifts significant cost to the K-C facility from the P&G facility. This is neither fair nor consistent with AB 32.

We believe that CARB should set only one benchmark for tonnage that can be applied equally to all types of tissue products. This approach is consistent with CARB's benchmark setting guidance and is the approach taken by the European Emissions Trading Scheme (“EU ETS"). If on some principled basis CARB determines that it must adjust tonnage for functionality, then, as demonstrated below, the only scientifically defensible basis upon which to do so is surface area. Accounting based on either tonnage or surface area fairly represents all types of tissue products, is based upon standard measurements utilized by the industry, is supported by evidence (unlike that of tonnage adjusted by water absorbency capacity), and incentivizes the reduction of GHG emissions per unit of finished product (KC 2).

Comment: While we support these objectives of the regulation now before the Board, we have very serious objections to the emissions benchmarks proposed for the tissue industry sector. We ask in the strongest terms possible that the Board direct the staff to reconsider the proposed benchmarks and prepare a new 15-day set of changes to establish the benchmark based on the normal 90 percent of the average standard. As a background, there are only two remaining tissue facilities in California. Each utilizes a different technology to manufacture tissue products. KC's technology emits significantly less greenhouse gases per ton of finished product. And as in most industries, greenhouse gas emissions are most closely correlated with tons production. Our first objection to the current proposed benchmark is that it discriminates against KC. It's discriminatory because it preferences one technology over another, increasing the compliance cost significantly more efficient technology, the one used by KC, while decreasing the other less sufficient one. This is not fair and not consistent with the statute of AB 32.

The second objective or objection to the proposal is that it's not supported by sound science and does not justify the departure from ARB's standard for setting product benchmarks, namely the 90 percent of the average greenhouse gas per ton of finished product. ARB's proposal sets the individual benchmark for each type of tissue which are paper towel, tissue, facial, wiper and bath, based upon the facility level emissions data, rather than emission data that's for each type of tissue which you need in order to set an individual benchmark. As a result, the individual benchmarks are inaccurate and do not reflect the actual greenhouse gas emissions.

Further, ARB only adjusted the individual inaccurate bath tissue benchmark to account for the functionality of the absorbency alone. There are other functionalities for tissue to be considered. So here's our ask. So ARB should set only one tissue benchmark based on tonnage alone that can be applied equally to all types of tissue products. This approach is consistent with ARB's benchmark setting guidance and is the approach taken by the European emissions trading scheme. If on some principle basis ARB determines it must adjust tonnage for functionality, the most reasonable and defensible option is to base it on surface areas, which is detailed in Kimberly-Clark's written comments. So in closing, we strongly encourage the Board to direct the staff to prepare a new set of 15-day changes that proposes a single benchmark that is in line with both AB 32 and our guidance. Thank you again for the opportunities to speak directly with you. And if you have any questions, I'll be welcome to answer them at this time. (KC 3)

Comment: It has been brought to my attention that the Air Resources Board this week is considering various amendments to the Cap-and-Trade Regulation - one being a change to the benchmark formula that determines the allowances received by tissue manufacturers. Based on concerns raised by Kimberly-Clark Fullerton Mill, I respectfully request that you reject this specific change.

The proposed benchmark change is based on a "water absorbency" factor that would increase allowances for one tissue manufacturer in the state; but reduce allowances for K-C. I'm told that the products between the two operations are very different - premium bath tissue versus facial tissue and value bath tissue. Also, absorbency of a product is not necessarily an indicator of how much greenhouse gases are emitted by the manufacturing process. In fact, I've seen studies that suggest that K-C Fullerton’s (issue manufacturing process emits less GHG than its competitor, which makes the more absorbent product. This change doesn't make sense if ARB is truly trying to minimize GHG emissions while minimizing loss of manufacturing jobs in the process.

For these reasons, I do not believe this change in the tissue benchmark holds up from an environmental or fairness standpoint and strongly urge you to maintain the current benchmark and reject the proposed change. We should not be picking winners and losers between the last two tissue manufacturers; particularly when the rationale for the proposed change is based on questionable data.

Thank you for your time and attention to this matter. Your strong consideration is appreciated. (CORREA)

> **Response:** ARB staff appreciates the comment. The proposed tissue benchmarks were developed based on CARB’s benchmark principles and do not favor one facility over another, but instead allow ARB staff to allocate to the sector based on the average greenhouse gas emissions efficiency required to produce a unit of product that achieves an equivalent task.
>
> After the first tissue benchmark was released in 2010 using short ton (weight) as the benchmark unit, it was brought to staff’s attention that using weight as a unit was favoring one facility over another because the same unit of weight could be associated with different amount of functionality. For example, a person might need 5 grams of Product A to accomplish certain tasks whereas it would require 10 grams of Product B to finish the same tasks. This is because different tissue

products can come in different fiber structures and densities. The proposed revision is designed to eliminate this inequity.

Product-based benchmark development requires quality data and detailed knowledge about manufacturing processes. ARB staff has been working with industry stakeholders over the last two-and-half years to obtain the necessary information and data to establish sound benchmarks. While benchmark development is straightforward for a manufacturing process where one homogenous product is manufactured at one facility, it can be complicated to define products when one facility can produce slightly different products from the same feedstock. Tissue paper production is an example of a case in which a facility can make different types of products (facial tissue, bathroom tissue, paper towels and delicate task wipers) from a single feedstock—cellulose fiber from wood.

Staff has been working with tissue producers to determine appropriate product definitions consistent with the one-product, one-benchmark principle. After the release of a benchmark as part of the 2010 regulatory package that grouped all tissue products and used weight as a benchmark unit, staff identified two issues (chronologically):

1. Tissue products can come in different fiber structures and densities. For covered products such as steel or glass, physical structure and associated density is reasonably homogenous—i.e., the same unit weight of product will be associated with comparable volume and one can safely assume that a unit weight of steel can perform equivalent amount of task regardless of its origin. Therefore, the use of tons as the benchmark unit is appropriate for those products. However, this is not the case with tissue, as the same unit weight of fiber can be used to make a 2-dimensional flat product or 3-dimensional fluffy product. Flat products have fewer voids and less volume, whereas fluffy products have more voids and higher volume. More voids can hold more water. In other words, the same unit weight of tissue can have different functionality.
2. Different tissue products are associated with different combinations of characteristics. Facial tissue is focused more on softness; bathroom tissue on the balance of softness, strength, and absorbency; paper towels on absorbency and strength; and delicate task wipers on their lint-free nature and strength.

Due to these complexities, staff has worked with stakeholders to propose new tissue benchmarks: first as part of the 45-day amendment package in 2013 and second as part of 1the 5-day amendment package in 2014. The history is explained in Page 15 of the Appendix A to the 15-day Modifications released on March 21, 2014.[232]

[232] http://www.arb.ca.gov/regact/2013/capandtrade13/2appabenchmarks.pdf

In the 45-day Modifications[233] to the regulation, released on September 4, 2013, staff proposed a change to the tissue benchmark to address the first issue above. The motivation for ARB staff to use a normalizing factor such as water absorbency capacity for tissue products is to minimize the number of benchmarks. For example, tomato benchmarks use tomato soluble solids to group tomato products that come in different concentrations. As stated in the Appendix C of the 45-day Modifications, staff proposed the use of a water absorbency factor for tissue to normalize the ratio of fiber and voids to address the shortcomings of weight as the benchmark unit. It was intended to enable the comparison of unit amount of fiber to perform the same amount of task.

After the release of the proposed benchmark in the 45-Day Modifications, one company commented that water absorption capacity was not an appropriate normalizing factor because different paper products are associated with different characteristics, as described in 2 (above). While staff's intention to use water absorption capacity was not to emphasize water absorption as a primary purpose or function for all types of tissues, staff agrees that it does not reflect other characteristics such as softness. One company proposed using total tissue weight divided by the mass per unit area of the finished product as an alternative normalization factor for water absorbency. Because this metric did not take into account thickness, it did not allow for the comparison of the unit amount of fiber to perform the same amount of task.

Because the different tissue products focus on different attributes (facial tissue focuses more on softness; bathroom tissue on the balance of softness, strength, and absorbency; paper towels focus more on absorbency and strength; and delicate task wipers on their lint-free nature and strength), and because the products have different purposes and different markets for the products, staff proposed to benchmark facial tissue, bathroom tissue, paper towels, and delicate task wipers separately. The commenter noted that there are other attributes of bathroom tissue that consumers take into account—primarily softness and strength—that could be considered in a product benchmark. While staff agrees that those attributes are important attributes of bathroom tissue, they do not address the primary functionality of the bathroom tissue, which is to absorb.

Staff allocated the emissions to different products using the same emissions intensity because no product-specific emissions data were available. If the sector wishes to provide more accurate data to ARB, staff would welcome these data. The commenter also mentioned that adjusting tissue benchmarks using water absorbency necessarily raises the benchmark and allows for greater GHG emissions. Staff does not believe this is the case, as the benchmark affects the allocation to the covered facility, not the emissions. Further, the cap in the Cap-and-Trade Program limits the total greenhouse gas emissions that all covered facilities can emit.

[233] http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

Finally, benchmark stringency is determined based on 90% of the average greenhouse gas emissions per unit product, or "best-in-class" when no facility achieves 90% of the average. Regardless, staff will continue to understand the sector's concerns and review new data and make adjustments to the benchmark, as necessary.

Comment: [*Note: The commenter provided an informational flyer. The content of the flyer is included below, however pictures have not been included*].

- Kimberly-Clark Manufacturing in California since 1956
- Operations - 600+ workforce
- Fullerton Mill - Consumer tissue (Kleenex, Scott, Kimtech Science)
- Since 1956
- 350 Employees, $85K avr pay
- Lake Forest HQ – Medical Devices
- California-founded in 1980
- 120 employees
- Pleasanton sales office – Safeway
- Redlands & Ontario DCs
- Other impacts
- $184 MM+ spent in 2012 with California businesses
- Energy self-sufficiency, recycling of process water & waste, workplace safety record
- $12 Million+ paid annually in California taxes
- Kimberly-Clark Products & Global profile
- Approximately 58,000 employees worldwide and operations in 37 countries. Approximately 14,000 U.S. employees.
- Global brands sold in more than 175 countries – Kleenex, Scott, HUGGIES, Pull-Ups, Kotex and Depend brands holding #1 or #2 market share in more than 80 countries.
- Net sales of $21 billion in 2012.
- *Health Care*
- Surgical drapes & Gowns, Infection control products, face masks, exam gloves; respiratory, digestive health, pain management & other disposable medical devices
- *Consumer tissue*
    - Facial tissue, bathroom tissue and wipers, paper towels
- *Personal care*
    - Diapers, training/youth/swim pants, feminine care, incontinence care, infant & child wipes
- *K-C professional*
    - Products for Away-From-Home
- Use: Facial tissue/bathroom tissue/paper towels; wipers; safety products; nonwovens (KC 4)

Response: Staff thanks the commenter for the information. The comment is outside of the scope of the proposed 15-day amendments to the Cap-and-Trade Regulation so no response is required.

B-4.2. Multiple Comments: The Procter & Gamble Paper Products Company recognizes the considerable effort CARB has invested in compiling extensive and detailed data to develop the proposed amendment which is consistent with existing benchmark principles. We agree and support the proposed regulation amendment on table 9-1for these product-based benchmarks that was posted for the 15 day public notice.

We thank the Board and CARB staff for their work on updating the Paper Mill product benchmark and for the opportunity to provide these comments on the tissue product benchmark revisions. (PG 2)

Comment: I wanted to come before you today to express our support for the latest amendment to the regulation for the tissue manufacturing product benchmark. We absolutely believe that this proposal recognizes the functional difference that was mentioned earlier between bath tissue, facial tissue, paper towels, and delicate task wipers. We recognize that this proposal demonstrates the scientific relationship for these functional requirements as can be supported by a globally recognized technical standard.

We feel that those standards are critical to defining the correct benchmark determination for our technology for our sector. P&G encourages your support of the regulation, the proposed amendments. (PG 3)

Response: Thank you for the support.

Gypsum Benchmark

B-4.3. Comment: The Plaster Board Manufacturing Benchmark for the Gypsum Product Manufacturing Industry should remain labeled “Plaster Board Manufacturing” as opposed to “Stucco Manufacturing”. The Gypsum Product Manufacturing (“GPM”) industry processes raw gypsum into stucco which is then used to produce saleable plasterboard. The main activity remains Plasterboard Manufacturing. Therefore, USG requests that the Activity be changed back to “Plaster Board Manufacturing” from “Stucco Manufacturing”.

The Plaster Board Manufacturing Benchmark for the Gypsum Product Manufacturing Industry should be revised from a Weight Based Metric to a Production Based Metric. The GPM industry agreed to use a benchmark of metric tons CO2e per short ton of stucco used to produce wallboard, which is in line with the EU ETS. With the GPM industry continually moving to lighter products using weight as a metric will not allow the industry to take advantage of improvements in energy utilization. Conceptually, if the denominator in the metric is weight based, and weight is continually decreased, members of the GPM industry may not be able to meet target CO2e allocations regardless of energy usage.

California has revised the Cap and Trade Regulations to harmonize its system with the cap and trade system that has been assembled by Quebec. Quebec has adopted an area based metric for the GPM industry (metric tons CO2e per cubic metre of gypsum panel). In keeping with the goal to harmonize these two cap and trade systems, the California Air Resource Board ("CARB") should also adopt industry benchmarks that are comparable wherever possible. USG believes that Quebec's method for setting the Plaster Board Manufacturing Benchmark is more appropriate as weight is not a factor in determining energy efficiency.

We propose that CARB solicit a new area based emissions benchmark from the GPM industry which may be coordinated through a trade association. The units of this benchmark should be in terms of *metric tons CO2e per msf ("thousand square feet") of wallboard produced.* (USG)

> **Response:** This comment is outside of the scope of the proposed 15-day amendments to the Cap-and-Trade Regulation so no response is required. ARB staff amended "plasterboard" to "stucco" on the recommendation of industry. There is no plan to amend it further at this point in time.

Tomato Processing Benchmark

B-4.4. Comment: Proposed Benchmarks May Require Additional Adjustments and Should Provide Additional Time for Implementation

While in general, the benchmarks meet the requirements faced by single product facilities or facilities with only a few additional products, for food processors with product lines of 100+ products, incorporating the benchmarks in quickly in order to meet the current year deadline presents immediate and possibly insurmountable problems.

Current benchmark a good start, but needs additional refinement.

The differences between food processing operations are as varied and unique as the variety of products that can and are produced. Using cost as the central factor, operations will vary significantly in energy, labor, container, labeling, and inventory control expenses. Theoretically, it may appear more cost-effective to produce some products, from an energy usage view, at the point of production but process complexity and resultant losses are difficult to quantify and add to production cost.

Production is by necessity dictated by customer and consumer demands and can only be adjusted, to a minimal extent, to address energy efficiency demands. Facilities vary in their ability to schedule long runs of one product or another, due to not only the demands of the customers, but also the quality and variety of the produce.

As a result, many facilities are faced with higher production costs, and in some cases increased inefficiencies, in order to meet customer commitments. Some food processors produce dozens of different products from a single evaporation system. (CLFP 3)

> **Response:** The product benchmarking development for the tomato industry was developed over two years, leveraging work from contractors Ecofys, U.C. Berkeley, and Northwestern University to provide additional expertise. The benchmarking was conducted and completed at the request of the tomato industry.
>
> Staff has consistently adhered to the longstanding ARB practice of one benchmark for one product. To recognize the various products produced at tomato processing facilities in California, staff proposed five separate benchmarks for this sector. While the commenter does not specifically characterize the changes being sought for the tomato product benchmarks, staff will continue to work with stakeholders in subsequent rulemakings to adjust the product-based benchmarks, as deemed necessary, pursuant to Board direction.

B-4.5. Comment: Accuracy requirements do not take into account natural variables. The proposed benchmarks require facilities to achieve an accuracy of less than 5% error on production reporting. Additionally, reporting facilities are not allowed credit for the baseline inaccuracy of the primary incoming product.

What isn't taken into account in CARB's proposed methodology is the raw product variability that occurs naturally and which each facility must manage in order to maintain product quality and consistency. ARB has set the base at 5.35% as the industry standard for solids and this is generally applicable. However, it should be noted that some facilities have had solids coming in as low as 4.3%. These numbers can be verified by State-run inspection stations.

Additionally, the inability to meet the error factor may be projected across some or all the product lines in a particular facility. This only increases the difficulty in achieving 5% accuracy as now there will be potentially hundreds of different products with different can sizes, ingredients, and concentrations that will need to be fit into the five categories provided by the benchmark. For some facilities, none of the five categories easily describe the vast majority of products produced by canning operations. Some processors have hundreds of products (SKUs).

Many food processing operations produce product to spec. That is, the buyer contracts for products that meet pre-specified requirements. Naturally, seemingly similar products can have a large variance of solids between two different customer contracts.

Given the need for specialized manufacture of formulated products with multiple ingredients, the manufacture and production are by nature, more labor and energy intensive. Given this complexity, parsing the products into the available categories will be difficult and time consuming initially. Additionally, verification by third parties unfamiliar with such processes will be difficult, if not impossible. (CLFP 3)

Response: The commenter's discussion of accuracy and verification requirements for product data are related to the Mandatory Reporting Regulation (MRR) and are outside of the scope of the proposed 15-day changes to the Cap-and-Trade Regulation. Therefore, no additional response is required.

As previously mentioned, the development of the tomato product benchmarks, including product definitions, was conducted over two years leveraging work from contractors Ecofys, U.C. Berkeley, and Northwestern University to provide additional expertise. The benchmarking was conducted and completed with stakeholder support. The definitions were chosen to best represent the emissions associated with production at tomato facilities. As such, these definitions break formulated products into their constituents: tomato paste, whole and diced tomatoes, and tomato juice. This captures the emissions of these products and allows facilities with a large number of diverse products to report in these categories. For more information on the development of these benchmarks, please see Appendix A: Product-based Benchmark Development, which was released with the March 2014 15-day changes.

The product definitions for the Cap-and-Trade Regulation were taken from MRR. The definitions for the tomato products in MRR were developed with the support of the industry. Staff would like to note that the commenter submitted public comments supporting these definitions in MRR (Comment A-24, December 2013 MRR FSOR).

B-4.6. Comment: The timeline for Incorporation of the proposed benchmark should be flexible enough to accommodate outlier facilities. (CLFP 3)

Response: ARB granted an extension to the reporting deadline for operators subject to new or updated product data reporting requirements under MRR. This extension was granted for tomato processing facilities. Please refer to the regulatory advisory for the extension, which provided a new deadline of May 9, 2014 for eligible reporters to supply the required product data.[234]

B-4.7. Comment: There are much simpler methods of allowing companies to grow than the complex and difficult to verify methodology proposed by ARB. Many facilities would support a method that would measure energy use per ton of incoming product. (CLFP 3)

Response: ARB has consistently utilized two different methodologies for industrial allocation: product-based benchmarking and energy-based benchmarking. The product-based allocation methodology is the preferred approach, as the allocation of allowances is updated annually based on the production of goods in California. This allows facilities to expand and produce

[234] Available online at: http://www.arb.ca.gov/cc/reporting/ghg-rep/regadvisory-deadline.pdf

more good in California, thereby minimizing leakage to the extent feasible. Staff proposed to switch from the energy-based allocation methodology to the product-based allocation methodology for the tomato-processing sector at the request of industry stakeholders.

B-4.9. Comment: Barring the development of an additional benchmark, there is a need for a more flexible time line for incorporating the energy accounting methodology articulated in the proposed benchmark categories for paste and canned products.

Currently, all food processing facilities are subject to the energy-based benchmark. While the regulation was updated late last year to require food processors to report production data, the development of the benchmarks lagged behind. Without the guidance necessitated by the benchmark, food processors lack the knowledge to determine what they will be required to report or how to report it. Many are unlikely to have made any changes in either their GHG Monitoring Plan or production tracking without guidance or clear and fully developed rules for reporting.

It has only been in the last few weeks that it was determined that the benchmarks would be ready for release in time for consideration by the Board in its April Board meeting. However, the reporting deadlines will occur three weeks before the Board has the opportunity to vote on the proposed benchmarks. (CLFP 3)

> **Response:** As previously mentioned, ARB granted an extension to the reporting deadline for operators subject to new or updated product data reporting requirements under MRR. This extension was granted for tomato processing facilities. Please refer to the regulatory advisory for the extension, which provided a new deadline of May 9, 2014 for eligible reporters to supply the required product data.[235]

B-4.10. Comment: Given the difficulty for many facilities to implement the benchmarks in the short time remaining before the deadline CLFP proposes the following:
Food processors should be given OPTIONS in application of product-based benchmark.
1. Processors should have option to remain under energy-based benchmark until January 1, 2015.

Many food processing operations may require more time to fully integrate a workable product-based benchmark into their production processes and incorporate it into their GHG Monitoring Plan. Facilities vary in their internal structures as well as their product categories. A food processor may be a large multinational corporation employing thousands of employees or a small family-owned operation with only a few hundred personnel. Some facilities are co-op owned while others employ alternative governance structures unique in the business world. Almost all CLFP members subject to the Cap-and-Trade are seasonal, operating a maximum of 110 days, with employee numbers that fluctuate annually. The point being that some facilities will have the manpower to

[235] Available online at: http://www.arb.ca.gov/cc/reporting/ghg-rep/regadvisory-deadline.pdf

dedicate significant resources to incorporating the new benchmarks into their compliance procedures whereas some will be hard pressed to do so. (CLFP 3)

> **Response:** For each industrial sector eligible for allowance allocation, ARB has consistently applied two methodologies for allocation: eligible industrial facilities that conduct an activity in Table 9-1 of the Regulation are allocated under the product-based allocation methodology, and all other eligible sectors are allocated allowances based on the energy-based methodology. As such, with the development of additional products and activities for the food industry in Table 9-1, all food processing facilities that engage in these activities will be allocated under the product-based allocation methodology. During development of the benchmarks for the tomato processing industry, staff reiterated to stakeholders that allocation under the previously used energy-based methodology would no longer be permitted upon adoption of any proposed product-based benchmarks.
>
> As previously mentioned, ARB granted an extension to the reporting deadline for operators subject to new or updated product data reporting requirements under MRR. This extension was granted for tomato processing facilities. Please refer to the regulatory advisory for the extension, which provided a new deadline of May 9, 2014 for eligible reporters to supply the required product data.[236]

B-4.11. Comment: 2. Food processors not responsible to delay in developing product -based benchmark.

As early as 2010, ARB was aware that the food processing industry presented a unique and difficult challenge to benchmark. The multitude of products, the varied processes employed in production, the variability associated with seasonal operations and weather/harvest -dependent production cycles all contribute to the difficulty in tackling a product-based benchmark.

Acknowledging these factors, ARB opted to impose the energy-based benchmark on the food processing industry. A year and a half was devoted to negotiations with ARB and to the development of a benchmark that would address the unique requirements of our industry.

However, in late 2011, ARB abruptly, and unilaterally, abandoned the energy-based benchmark effort and decided that food processors would be subject to the product-based methodology. This is the primary basis for the delay in settling the benchmarks at this late date for the food processing industry.

A synopsis of those subsequent efforts on the product-based benchmark development can be found in staff documents filed in this proceeding.1 (CLFP 3)

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[236] Available online at: http://www.arb.ca.gov/cc/reporting/ghg-rep/regadvisory-deadline.pdf

Response: The request to develop product-based benchmarks for the food processing industry was at the request of stakeholders in the sector, primarily because the energy-based allocation methodology does not allow for expansion. ARB staff developed product-based benchmarks for the industry over two years leveraging work from contractors Ecofys, U.C. Berkeley, and Northwestern University to provide additional expertise. The benchmarking was conducted and completed with stakeholder support.

B-4.12. Comment: 3. Giving Food Processors the option of remaining under the thermal benchmark benefits both food processors and ARB.

ARB staff has made it clear that they wish to have the food processing industry under the product-based benchmark in time to determine allocation assistance for 2014. Those processing facilities contemplating possible expansion are also desirous of implementing the product benchmark as soon as practicable. The all food processors subject to these proposed requirements have worked with ARB in trying to meet these deadlines. Some have succeeded. And they should be allowed to do so.

However, other than informally citing the "inconvenience" of having to calculate the industry assistance under both the thermal and product benchmarks, ARB staff has not presented any evidence that providing the option to remain under the thermal benchmark to food processors, for this year only, will significantly harm or alter the Cap-and-Trade program. (CLFP 3)

Response: For each industrial sector eligible for allowance allocation, ARB has consistently applied two methodologies for allocation: eligible industrial facilities that conduct an activity in Table 9-1 of the Regulation are allocated under the product-based allocation methodology, and all other eligible sectors are allocated allowances based on the energy-based methodology. As such, with the development of additional products and activities for the food industry in Table 9-1, all food processing facilities that engage in these activities will be allocated under the product-based allocation methodology. During development of the benchmarks for the tomato processing industry, staff reiterated to stakeholders that allocation under the previously used energy-based methodology would no longer be permitted upon adoption of any proposed product-based benchmarks.

B-4.13. Comment: 4. Providing the option to remain under the energy-based benchmark for 2014 only, will allow ARB to finish the benchmark and make necessary changes to Cal e-GGRT to properly align the new definitions with the reporting requirements.

At this time, CLFP understands that some of the products to be reported will require additional fields to inserted into Cal e-GGRT to allow for reporting. Many of the new definitions will require fine tuning over the coming months as well, in order to accurately reflect the production categories that are being established under the proposed product-based benchmark. Some of the definitions are redundant, describing two or three different products with identical language for each. For food processors, and especially for canning operations, reporting will mean sorting through hundreds of SKUs with a breakdown of product components according to definitional divisions for reporting. In some cases the definition inaccuracies will require changes or editing. Moreover, such "on-the-fly" changes could present verification problems for facilities that will require additional time and effort to correct or defend.

It would be far more efficient to allow those companies that wish to remain under the energy-based benchmark until 2015 to do so. This will provide ARB with the necessary time to finalize the definitions and reporting tool changes and give the facilities with multiple formulated products to incorporate the product-based benchmarks into their GHG Monitoring Plans with a high degree of confidence that future reporting will be accurate. (CLFP 3)

> **Response:** Amendments to MRR became effective on January 1, 2014. The addition of the food definitions as part of the MRR rulemaking process were supported by the commenter (Comment A-24, December 2013 MRR FSOR). Staff believes the product definitions are complete and necessary to fully describe the food industry and Cal e-GGRT has included the necessary fields.

B-4.14. Comment: 5. Some facilities need extra time to develop workable methodologies for applying benchmark energy intensity factors to product production.

As noted previous, some facilities, such as paste processors, may have only one main product, with a few additional products that they will need to account for. However, a canning operation can have between 100 up to 300 separate products with multiple formulations that will need to be categorized under the reporting requirement. A failure to properly or fully incorporate the benchmark into product production may result in adverse impacts for a food processor as the result of inaccurate reporting. Just a few include:

a. Improper application of benchmark could subject food processor to penalties for inaccurate reporting under the certification requirement.

b. Improper application could result in problems with verification of production data – resulting in costly reviews of records and methodologies.

c. Timing is bad for incorporation of methodology as it conflicts with ongoing preparations for processing season. (CLFP 3)

> **Response:** The development of the tomato product definitions were developed over two years, leveraging work from contractors Ecofys, U.C. Berkeley, and Northwestern University to provide additional expertise. The project was conducted and completed with stakeholder support. The definitions were chosen to best represent the emissions associated with production at tomato facilities.

As such, these definitions break formulated products into their constituents: tomato paste, whole and diced tomatoes, and tomato juice. This both captures the emissions of these products and allows facilities with a large number of diverse products to report in these categories. For more information on the development of these benchmarks, please see Appendix A: Product-based Benchmark Development released with the March 2014 15-day changes.

ARB granted an extension to the reporting deadline for operators subject to new or updated product data reporting requirements under MRR.

B-4.15. Comment: 6. Until Product-based Benchmarks are ratified by Board vote, food processors remain subject to energy-based benchmark.

The deadline for reporting 2013 production data for the current year is April 10, 2014. However, the official vote for adopting the proposed benchmarks will not occur until at least April 24, 2014. This presents a problem for both ARB and for food processors wishing to have their upcoming allowance allocations calculated on a product basis.

The best solution is to provide the option to food processors to either adopt the product-based benchmark prior to the authorizing vote, or to remain under the energy-based benchmark until the benchmarks are officially approved and added to the Cap-and-Trade regulation. (CLFP 3)

Response: The reporting deadline is contained in MRR. Amendments to MRR became effective January 1, 2014. This requires facilities to report under the new product definitions.

Allocation is proposed to occur by October 24, after the Board vote in April 2014. Thus, there is no inconsistency between reporting and allocation.

B-4.16. Comment: Proposed benchmark does not account for non-tomato production lines.

The proposed benchmarks fail to take into account non-tomato production at tomato facilities. A number of plants process non-tomato products (chilies, peppers, etc.) that are not utilized in formulated tomato products but are packaged and sold as an actual end product. CARB will need to revisit this issue in order ensure that production data is accurate as well as ensure that each facility will receive its proper allotment of allowances based on its entire production. (CLFP 3)

Response: In the development of the tomato product benchmarks, there were insufficient reporting facilities with non-tomato canning lines reported on production. Thus, staff was unable to develop non-tomato benchmarks.

As far as non-tomato ingredients in tomato based products, staff chose not to allocate for this separately. Since tomato products include spices, vegetables and other additives, staff included the energy of these products in the development of tomato based benchmarks. Thus, the carbon costs associated with adding these ingredients are included in the tomato benchmarks.

B-4.17. Comment: Definitions for many products are redundant and should be combined or redefined

Food processors, especially those involved in tomato processing, are concerned with the apparent redundancy in the product definitions and the risk that it will contribute to confusion in reporting under a product-based benchmark. Some food processors have well over 100-plus products that must be broken down per the definitions and assigned categories prior to reporting. Sorting through similar definitions that don't exactly specify the actual product will lead to confusion in how to report as well as delay in completing the report and likely to result in inaccurate reporting. Elimination of the redundant product definitions is preferred and CLFP recommends that CARB staff work with the food processing members to more accurately define the types of products. This will serve to eliminate confusion and potential inaccuracies associated with production data reporting. (CLFP 3)

Response: The product definitions for the Cap-and-Trade Regulation were taken from MRR. The definitions for the tomato products in MRR were developed with the support of the industry. The commenter submitted public comments supporting these definitions in MRR (Comment A-24, December 2013 MRR FSOR). Furthermore, the commenter does not specify the changes being sought for the food product definitions.

B-4.18. Comment: II. Retroactive Application of New Product-based Benchmarks on Production Data Previously Calculated Under the Alternative Thermal-based Methodology Should be Limited to Rectifying Under Allocation of Allowances Only

ARB's intention to retroactively apply the proposed product-base benchmarks to production data originally calculated under the energy-based benchmark should be limited to correcting under allocations to facilities during the initial compliance period. As the result of the retroactive application of the product-based benchmark, some facilities will profit, while others will be forced to materially change position in that they will go from having a surplus of allowances to incurring an additional obligation. ARB should limit the effects of the retroactive application of the proposed product-based benchmark on past energy-based allocations to only providing additional allowances where it is determined that a facility was under allocated allowances.

Facilities under allocated in previous years should be made whole

ARB should make every effort to make whole those facilities that, subject to the energy-based benchmark, were under allocated allowances in previous years. If through the retroactive application of the proposed product-based benchmark additional allowances will be issued, it should be noted that the relative value of the allowances will be greater as a result of the automatic increases in floor prices in the regulation. However, as the under allocation is essentially a loss of use of funds that should have been available to the facilities, the subsequent increase in value due to the passage of time could rightfully be considered “interest” for purposes of this true-up.

However, ARB’s intention to withhold or deny present allowances, which would be issued under the current product-based benchmark, as the result of an alleged over allocation when an obligated entity was required to report under the energy-based benchmark, will create a competitive disadvantage and financially harm those facilities that relied on those previous allocations distributed under the energy-based system. (CLFP 3)

> **Response:** The true-up allowances account for changes in production or allocation not properly accounted for in prior allocations. The true-up allowances maintain the correct incentives by linking a facility’s covered emissions to the actual production that year. If a facility produces more than earlier, it will receive additional allowances; if less, it will receive fewer allowances. An allowance represents the right to emit up to one metric ton of carbon dioxide equivalent. It is not a financial instrument that would be associated with “interest.” Furthermore, the change from energy-based to product-based allocation methods was requested by the sector.

B-4.19. Comment: Retroactive application of benchmark should be limited to providing additional allowances under allocated facilities only

A. Benchmarks developed at different times, under different circumstances

Circumstances existing at the time the allowances were issued to facilities subject to the energy- based benchmark have substantially changed over the past two years. A retroactive application of the proposed product-based benchmark will undermine an obligated facility’s current position based on assumptions, changed circumstances, market differences, and financial factors relied upon at the time the allowances were issued. For instance, the drought was not in issue in the decision making processes of processors to the degree it is now. Increased costs due to factors not present two years ago will increase the harm of withholding allowances under current circumstances. (CLFP 3)

> **Response:** The true-up allowances account for changes in production or allocation not properly accounted for in prior allocations. The true-up allowances maintain the correct incentives by linking a facility’s covered emissions to the actual production that year. If a facility produces more than earlier, it will receive additional allowances; if less, it will receive fewer allowances.
>
> The program is designed to deal with fluctuations in emissions and production by using three-year compliance periods. These compliance periods mean that an entity surrenders most of their allowances at the end of the program. This

smooths out spikes in emissions due to any annual variation as they are expected to average out during the compliance period.

B-4.20. Comment: B. Facilities Made Business and Financial Decision Based on Allocations Received. Companies that received allowances under the energy-based benchmark made forward-looking financial decisions based upon the current value of the allowances issued at that time. Businesses make financial, market, and capital investment decisions over multiple years – anticipating two, three, or five year investment goals. ARB cannot simply strip away the alleged "over allocations" based on the retroactive application of a present day benchmark without creating financial consequences to the company. (CLFP 3)

Response: The true-up allowances account for changes in production or allocation not properly accounted for in prior allocations. The true-up allowances maintain the correct incentives by linking a facility's covered emissions to the actual production that year. If a facility produces more than earlier, it will receive additional allowances; if less, it will receive fewer allowances. An allowance represents the right to emit up to one metric ton of carbon dioxide equivalent. The change from energy-based to product-based allocation methods was requested by the sector.

B-4.21. Comment: C. No Expectation at the time that a Product-based Benchmark would be Applied in Future resulting in loss of allowances. At the time the allocations were distributed to all the food processors then, and currently, under the Energy-based benchmark, ARB provided no warning or notice that such allocations may be subject to a future true-up as the result of the retroactive application of a future product-based benchmark. In making business decisions, facilities had a right to rely on ARB's use of the energy-based benchmark in the allocation of the allowances at that time. (CLFP 3)

Response: In developing the product benchmarks, participating stakeholders have been made aware of the true-up mechanism. The true-up was expanded in the 45-day changes to take into account changes in allocation methodology. This benefits efficient facilities or facilities that have expanded production in California. During the benchmarking process, the industry has been supportive of this mechanism.

B-4.22. Comment: D. Present and Past Dollar value of allocations not equivalent. The allowances distributed by ARB subject to the assistance factor have a built in mechanism in the regulation that increases the floor value of the allowance automatically. Allowance value increases by Consumer Price Index plus 5% annually. This means the value of the allowances issued in year t-2 are of a lesser monetary value than those issued in year t. Based upon the relative values of the allowances in years t and t-2, facilities determined by ARB to have been "over allocated" allowances will lose substantially more monetary allowance value than was issued in t-2 as a direct result of the retroactive application of the product-based benchmark. (CLFP 3)

Response: Allowances are fully fungible and can be banked to be used for future years. Additionally, true-up allowances are available for immediate use in the compliance obligation for emissions associated with the calendar year two years prior. This true-up mechanism and immediate use of true-up allowances in a compliance obligation links the allocation with the emissions of that calendar year.

Additionally, allowances are freely distributed and represent the right to emit up to one metric ton of carbon dioxide equivalent. ARB does not place a monetary value on the allowances. The change from energy-based to product-based allocation methods was requested by the sector.

B-4.23. Comment: E. Definition of "true-up" different at time allocations were made. The proposed benchmark provides a changed definition for true-up meant to justify the retroactive application of the proposed product-based benchmark on the energy-based allocations. At the time the allowances were allocated to facilities subject to the energy-based benchmark, a true-up referred only to the timing and amount of the surrender of allowances in a given compliance period. For example, any company that chose to surrender 30% of its allowances for each of the first two years of the three-year compliance period would be subject to a true-up in the final year of 100% plus the additional allowances necessary to meet the total emissions over the entire compliance period.

Given the multiple changed circumstances in both allowance pricing and the market positions of the obligated facilities resulting from the passage of time, facilities had no way of knowing or acquiring an understanding or foreknowledge necessary to incorporate an allowance loss based on an unforeseen retroactive application by ARB of present day methodologies in determining industry assistance factors. It is patently unfair, and will result in measurable competitive and financial disadvantage to targeted facilities, to strip away allowances based on the proposed true-up provision in the latest proposed regulation changes. (CLFP 3)

Response: The true-up allowances account for changes in production or allocation not properly accounted for in prior allocations. The true-up allowances maintain the correct incentives by linking a facility's covered emissions to the actual production that year. If a facility produces more than earlier, it will receive additional allowances; if less, it will receive less allowances. A true-up mechanism has always been part of the product-based allowance allocation equation.

The program is designed to deal with fluctuations in emissions and production by using three-year compliance periods. These compliance periods mean that an entity surrenders most of their allowances at the end of each compliance period. This smooths out spikes in emissions due to any annual variation as they are expected to average out during the compliance period.

Transportation Fuels

B-4.24. Comment: And finally, with January 1, 2015, coming around and transportation fuels coming to this program, we really do want to recognize the Board's continued confidence in this program and bringing those fuels into the program is really something that California is remarkable for its achievement. And we need to continue the progress as the Board sees the implementation of this program for being the first of its kind to bring such a large set of emissions into market-based emission reduction program. (EDF 3)

> **Response:** Staff thanks the commenter. This comment is outside of the scope of the proposed 15-day amendments to the Cap-and-Trade Regulation so no additional response is required.

B-5. Allocation to Public Wholesale Water Entities

B-5.1. Comment. Starting with the release of the Cap-and-Trade Preliminary Draft Regulation in November 2009, Metropolitan has actively participated in the California Air Resources Board's (CARB) rule-making process for the sole purpose of protecting Metropolitan's customers from the adverse financial impacts of the Cap-and-Trade program. Metropolitan has submitted numerous written comments and has provided oral testimony to CARB. At multiple meetings, CARB members have noted that the water sector has been overlooked in the drafting of the Cap-and-Trade Regulation. They have directed staff in several resolutions to continue working with the water sector to adequately address its legitimate and unique issues, and to resolve its inequitable treatment under the Cap-and-Trade Regulation. However, despite numerous meetings and an extensive exchange of information, CARB staff has not successfully resolved the concerns of the Public Wholesale Water Agencies. Metropolitan appreciates the effort that CARB staff has put into formulating an allocation of allowances for Metropolitan, and the slight increase in the proposed allocation in this most recent revision. However, the Proposed Modifications must be further revised in order to, once and for all, provide a fair and equitable allocation of allowances to Metropolitan that will provide satisfactory mitigation for the cost burdens unquestionably imposed by the Cap-and-Trade regulations.

Comments on Allowance Allocation Methodology: As stated in previous comments and during meetings with CARB members and staff, Metropolitan is not an EDU and as such does not fall under the Renewable Portfolio Standard (RPS) requirement. To incorporate the EDU RPS requirement in the methodology to determine an allocation of allowances for Metropolitan is not appropriate. The characteristics of the electrical energy requirements of Public Wholesale Water Agencies are unique and different from those of EDUs. As such, the determination of allowances for Public Wholesale Water Agencies should take that into account.

CARB has inappropriately applied the standard EDU RPS requirement percentages (increasing from 21% in 2013 to 33% in 2020) to Metropolitan, and, in particular, applied them against Metropolitan's total CRA electrical load. This results in an allocation of allowances that not only fails to provide sufficient mitigation of Metropolitan's cost burden, but also, perversely, penalizes Metropolitan for having acquired such a large amount of GHG emissions-free resources. This is apparent from the results of CARB's calculations in Table 9-5 of the Proposed Modifications. In years 2019 and 2020 Metropolitan's allowance allocation would have been zero (or actually negative) except for the use of an Energy Efficiency Credit of 3,908 allowances. These values are the result of applying an increasing RPS percentage, up to 33%, to the entire CRA load when, on average, 70% of the load is already met with hydroelectric power and in some years the entire load is satisfied with hydroelectric power. The implication of such results is that Metropolitan must acquire renewable energy resources that will typically be surplus to its needs, requiring it to dispose of the surplus renewable energy or energy from its hydroelectric resources. This is not a reasonable or desirable outcome and shows the inappropriateness of using the standard EDU RPS requirement in the methodology to determine an allocation of allowances for the Public Wholesale Water Agencies.

In essence, the methodology in the Proposed Modifications fails to adequately address Metropolitan's cost burdens because it emulates the allowance allocation methodology used for the EDUs only with respect to the reduction of allowance allocations. Since the EDUs are required to meet the RPS requirements, a reduction in allowances commensurate with meeting these standards is logical and fair. Such a reduction is consistent with mitigating actual Cap-and-Trade customer costs since the costs of RPS compliance to the EDUs' customers are independent from the costs of Cap-and-Trade compliance.

Now CARB has decided to provide free allowances to the Public Wholesale Water Agencies to offset some of their direct costs of purchasing allowances. However, CARB's methodology to determine the amount of allowances uses the same process of reducing the allowances by incorporating the EDU's RPS requirement. By reducing the Public Wholesale Water Agencies' allowance allocation based on a requirement applicable only to EDUs, the Proposed Modifications do not mitigate the water agencies actual direct compliance costs in the same manner that the original Cap-and-Trade regulations mitigate the EDUs' actual costs to customers. This lack of cost mitigation will be especially onerous given the additional drought related costs Metropolitan is currently experiencing.

Recommended Allocation Approach: Metropolitan does recognize CARB's desire to incentivize the acquisition of renewable energy. If CARB determines that it must apply standard RPS percentages to Metropolitan's allowance allocation, a more appropriate and equitable method would be to apply the RPS percentages on the average amount of supplemental energy Metropolitan uses on the CRA. This approach is consistent with the comments of CARB Member De La Torre at the October 25, 2013, CARB meeting:

"And to me, it's pretty clear that hydro by definition is not polluting. So that should not be included in whatever formula, whatever mechanism that we use….I think the hydro component should be subtracted from whatever it is that we're asking them to do to mitigate….whatever metric you want to choose that's a reasonable number for how much hydro they've gotten over the last several years on a going forward basis they should not have to offset that or mitigate that." Tr. at 178-79.

This recommended approach uses the same process as CARB's original calculations and bases the increasing annual amount of renewable energy on the average supplemental energy Metropolitan uses, as CARB Member de la Torre suggests, instead of the total CRA demand. Using this approach, the following table provides the annual allocation of allowances for Metropolitan that should be used in lieu of Table 9-5 in the Proposed Modifications:

Table 9-5: Allocation to Each Public Wholesale Water Agency Annual Allocation

	2015	2016	2017	2018	2019	2020
Metropolitan Water District	496,268	153,110	148,256	154,387	147,019	139,993

In response to Metropolitan's comments and the direction provided by CARB members at the October 25, 2013 meeting and in Resolution 13-44, CARB staff has attempted to address Metropolitan's concerns by marginally increasing the allowance allocation in the Proposed Modifications for year 2015 from 136,491 to 182,499. The increase is appreciated; but it is inadequate in addressing Metropolitan's cost burden. The recommended methodology proposed above will, however, satisfy the goals of both CARB and Metropolitan, by both incentivizing the acquisition of renewable energy and mitigating Metropolitan's cost burden for Cap-and-Trade compliance. This will be accomplished by applying the same general methodology CARB has used for other entities while making appropriate modifications for Metropolitan's unique characteristics, so it is a fair and reasonable approach for CARB to adopt. Metropolitan believes that regulations and legislation which provide for accommodations for unique and special circumstances, particularly regarding public agencies with large amounts of hydroelectric resources, have been developed in the past and should be applied in this situation. (MWD 3)

> **Response:** Most of this comment is outside of the scope of the proposed 15-day changes. ARB staff responded to the commenter's concerns and explained the basis for our allocation to a water agency in the responses to the commenter's 45-day comments. In the 15-day Modifications, staff increased the allocation to the commenter because staff modified the formula used for calculating cost burden to provide extra allowances to MWD that were not provided to EDUs by assuming that MWD would meet the equivalent of RPS requirements more slowly than the EDUs. ARB does not provide allowances to any other water agency, even though all water agencies face indirect GHG costs that they will pass through to their ratepayers.
>
> ARB staff recognizes the drought situation and the increased pumping of the Colorado will continue working with MWD to explore approaches to address MWD's specific concerns, including any potential adjustments to allocation for

B-5.2. Comment: I'm Kathleen Cole, legislative representative for the Metropolitan Water District of Southern California. Metropolitan is the regional water wholesaler for six county service area in Southern California. We provide drinking water for 19 million residents and businesses to support the region's one trillion dollar economy. Metropolitan has indeed been an active participant in CARB's rulemaking on the cap and trade reg. We have submitted numerous written comments, provided oral testimony to CARB, and have been working directly with many of you and your staff since November of 2009.

This year illustrates the strong relationship between the availability of water from the State Water Project and the energy requirements of Metropolitan's own Colorado River aqueduct system. Due to the severity of the current drought, Metropolitan will receive only a five percent allocation from the State Water Project in 2014. This lack of water from the State Water Project will require Metropolitan to operate its Colorado River system at peak capacity and load from March through the end of this year to meet the water demands in Southern California.

If the drought continues into 2015, the Colorado River system will continue to operate at peak capacity and Metropolitan will continue to acquire supplemental energy. While we can agree that as a public water wholesaler our situation is unique, we do not cleanly fit into this program and ask an accommodation so that Southern California water rate payers are treated similar to other utilities throughout the state.

We have noted that CARB has made an accommodation to agencies like San Francisco PUC, Trinity Public Utilities Districts and others and are asking for similar consideration. We certainly appreciate the efforts of CARB members and staff to find an equitable and fair solution for Metropolitan, and we are committed to continue our efforts to resolve concerns and in light of the State's dire water supply situation. We thank you for your consideration. (MWD 4)

Response: While ARB staff agrees that MWD is somewhat unique, staff notes that, as a result of the current drought, many water agencies will need to pump groundwater instead of accessing surface water because surface water rights will be curtailed. The cost of pumping ground water, on average, is higher than the cost of pumping surface water from rivers or reservoirs. What this means is that many water agencies in all parts of the State will face higher electricity costs for pumping.

After working with MWD for several years, ARB allocated allowances to MWD to be placed in MWD’s compliance account, in part because MWD is the only water agency with a direct compliance obligation. No other water agency in the state received any allocation. ARB staff recognizes the drought situation and the increased pumping from the Colorado system and will continue working with MWD to explore approaches to address MWD’s specific concerns, including any potential adjustments to allocation for future Board consideration.

San Francisco Public Utilities Commission (SFPUC) and Trinity Public Utilities District are allocated allowances because they are electricity distribution utilities (EDU), which MWD is not. ARB used a methodology to allocate allowances to MWD derived from the methodology used for allocating to EDUs. The allocation methodology for MWD is more generous to MWD than a comparable allocation if MWD were an EDU, because the allocation calculation for MWD assumes that renewable energy requirements applied to MWD would be less stringent than renewable energy requirements that apply to EDUs. There are two exceptions. Renewable energy requirements are not applied to SFPUC and Trinity because the electricity used to serve their ratepayers is more than 90 percent hydroelectricity. It would unreasonable to apply the renewable energy requirement to these two EDUs because it would be impossible for them to meet renewable energy requirements without selling off their zero emission hydropower.

B-6. Refinery Allocation

Complexity Weighted Barrels v. Carbon Dioxide Weighted Tonnes

B-6.1. Comment: We clearly support the transition from CWT to CWB. (WSPA 6)

Response: Thank you for the support.

Regulatory Process – Support

B-6.2. Comment: It is important to recognize the continuing effort by ARB to communicate with, and understand, the issues identified by the many stakeholders who are affected by the C/T program. While unresolved issues remain, the process used by staff to develop the final proposal recognized the important and dynamic balance between a transparent process and the need to protect confidential business information associated with a market-based system to reduce GHG emissions. We appreciate the efforts by staff who went to great lengths to explore issues and identify possible solutions. (WSPA 5)

Response: Thank you for the support.

Regulatory Process - Objections

B-6.3. Multiple Comments: From the time staff introduced its policy to separately benchmark smaller, less-complex refineries at a workshop held on October 7, 2013, through stakeholder meetings as recent as March 5, 2014, ARB staff had consistently presented two benchmarks for the industry to review and analyze, and for the Board to approve as the policy direction. The two categories of refineries were known as Atypical (smaller, less- complex refineries) and Typical (all other refineries). Over those 150 plus days, ARB has held a refinery- specific workshop, a full Board Hearing (with corresponding resolution), released an INFORMAL DISCUSSION DRAFT, released a refinery-specific technical document, and held an "all-refinery" meeting, all of which presented two refinery benchmarks. Stakeholders only learned about the policy reversal with the March 21, 2014, release of the Proposed Amendments (which were advertised as final regulatory language). The Coalition firmly objects to this last minute change in policy direction and views it as an affront to the regulatory process and Administrative Procedure Act. …

Over 18 months worth of stakeholder process, including multiple workshops and expert testimony, was completely overturned in the last two weeks preceding the release of the Proposed Amendments without any industry input or knowledge. This timeline is laid out explicitly in Attachment A to these comments and is well established by the record in this proceeding. Additionally, ARB exclusively conducted an "informal" process such that released documents and industry comments are not part of the official administrative record. Attached as Attachment D is staff's "Discussion Draft – January 31, 2014 Potential Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms" which incorporates provisions, definition and draft regulatory language for two benchmark values. Attached as Attachment G is staff's technical paper "Cap-and-Trade Regulation: Proposed Benchmarks for Refineries and Related Industries" dated February 26, 2014. This release too discusses separate benchmarks and proposes the revised values of such following correction of discovered calculation errors. The Coalition attaches these documents, along with others, in order to complete the official record.

ARB staff informed Coalition members verbally after release of the Proposed Amendments that analysis of "new information/data" was used to make the final policy decision which staff refused to share or elaborate on despite numerous requests. Staff however later confirmed that the final published benchmarking curve is based on a data set identical to the data set used for benchmarking curves published on February 26, 2014 (Attachment G), in which staff supported having separate benchmarks. No additional data or information has been presented to support this divergent change in policy – indeed, the data reflected in the record remains identical to the data that staff previously used to justify a separate Atypical benchmark.

The starting position of staff for refinery benchmarking back in 2012 was the generic "one product one benchmark," but based on months of stakeholder dialogue, data analysis, expert testimony and policy discussions with stakeholders, staff proposed at an early October 2013 workshop to separately benchmark the State's "Atypical" refineries. This position was re-affirmed by staff at the October 2013 Board Meeting, and the ARB Board agreed with the approval of Resolution 13-44 and Attachment A. Subsequent document releases, albeit "informal" in January 2014 and February 2014, along with a verbal reaffirmation at an all-refinery meeting in early March 2014 was consistent with the Typical/Atypical proposal.

The decision to establish two benchmarks rather than one is a policy decision. Such decisions are reserved for the ARB Board. By presenting the Board with two benchmarks in October, and only one benchmark in April, ARB staff has circumvented the Board's explicit direction under Attachment A to Resolution 13-44. Therefore, no vote should be taken until the Board has the opportunity to review the issue, hear from all impacted parties, and have the ability to change direction if so desired. [The attachments mentioned by the commenter are not included here, but are part of the regulatory record.] (CFEA 6)

Comment: Alon and CARB have worked together continuously for more than a year on these issues, and we are very disappointed by the 11th hour policy reversal. From October to March, the entire discussion between Alon and CARB was to ensure accurate data to set two separate benchmarks.

With a final vote scheduled for April, Alon requests that the item not be open for a final vote of the Board. Rather, additional time be granted to allow both Staff and stakeholders to have some additional time to review together the underlying data and assumptions that went into the policy decision at hand. Alon believes that CARB staff used insufficient data to draw their conclusions and therefore requests additional time to work through the issues with staff after direction is provided by the Board. …

Alon supported the proposed California-specific atypical criteria metrics of less than 12 process units and 20 million barrels of crude throughput per year. Staff's removal of this category is a very significant POLICY change at the end of a long regulatory process. Such policy changes are reserved for the Board, and can not be conducted in a 15-Day review package, especially one released right before the entire package is presented to the Board in a "thumbs up/thumbs down only" vote. (PARAMOUNT 4)

Comment: The starting position of ARB for refinery benchmarking for the second and third compliance periods back in 2012 was the generic "one product one benchmark" despite ARB's inability to adopt a single approach for the first compliance period. But, after months of stakeholder dialogue, data analysis, expert testimony and multiple refinery-specific workshops, staff proposed at an early October 2013 workshop to separately benchmark the State's "atypical" refineries. By contrast, the switch to a single benchmark occurred behind closed ARB doors over a matter of two weeks without any input sought from industry or warning given before the release of the Proposed Amendments. ARB's proposal to set a single benchmark disregards the established record and inexplicably relies upon an identical refinery dataset staff previously relied upon to justify a separate atypical benchmark. …

Given the varying levels of input on those positions – 18+ months with input from stakeholders, experts and staff versus 2 weeks without any input – the justification for the atypical benchmark is on a much stronger policy and procedural position. …

On August 28, 2012, ARB's own expert Ecofys suggested ARB consider separately benchmarking Kern and other "atypical" refineries.[237] Despite multiple meetings, beginning in November 2012, and comment letters highlighting the issue, Kern could not get staff to analyze the sector data or substantively respond to Kern's concerns. The lack of progress prompted Kern to join with similarly situated refiners to engage ARB staff and Board members to protect smaller, less complex refineries from the competitive disadvantages of a single benchmark.[238]

Testimony provided by worldwide acknowledged refining expert Solomon Associates (Solomon) and Ecofys at an ARB workshop held August 13, 2013, proved to be a turning point in the proceeding…

On October 7, 2013, staff proposed to separately calculate a CWB benchmark for atypical refineries citing to the previous workshop and further data analysis.[239] At the October 25, 2013, Board meeting, staff presented dual benchmarks and the Board directed staff to finalize those benchmarks in Resolution 13-44. During its presentation

[237] August 28, 2013, Ecofys Preliminary Work Product, p. 44 "Exclusion of Atypical Refineries"; p. 45 "Table 11: Potentially atypical refineries together with indication for not being a 'mainstream' refinery".
[238] Kern, Alon USA, Inc., San Joaquin Refining Co. Inc., Lunday-Thagard Refining Co., and Phillips 66 (on behalf of their Santa Maria facility) eventually formed the Coalition for Fair and Equitable Allocation.
[239] October 7, 2013, Cap-and-Trade Refineries and Related Industries Workshop, Staff Presentation, pp. 5, 14.

to the Board, staff highlighted being “in constant communication with industry stakeholders and members of the public ensure [sic] an open and transparent rulemaking process, including workshops and regular meetings with stakeholders.”[240] A nuance of the refinery benchmarking proposal linked facilities staff saw as “jointly operated” for purposes of an atypical determination, which prompted comments from several Board members and directions for staff to engage stakeholders to resolve that issue.

Staff rebuffed meeting requests after the October 2013 Board meeting asserting that all information related to the anticipated package was “market sensitive” and therefore could not be discussed prior to release. On January 31, 2014, after data confirmation, staff released an informal discussion draft regulation that included lower atypical and typical benchmark calculations attributed mostly to staff calculation errors. The release also included a revised “jointly operated” definition that proved problematic and had unintended consequences (i.e., it “linked” facilities that staff did not intend to link). On February 26, 2014, staff released another informal document entitled “Cap-and-Trade Regulation: Proposed Benchmarks for Refineries and Related Industries,” which slightly adjusted the typical and atypical benchmarks after final data confirmation and re-affirmed in writing staff’s intent to include two benchmarks in the 15- day Package. On March 5, 2014, staff held an all-refiner meeting to discuss the February release focusing on the “jointly operating” issue, which staff continued to struggle in defining and/or justifying. No indication was given that staff had any intention to drop the atypical benchmark.

On March 21, 2014, staff released the Proposed Amendments, which included a single refinery benchmark. In a subsequent telephone conversation, staff cited to “new information” and “new data” from two different Coalition for Fair and Equitable Allocations members (not Kern) that largely served as the basis for the policy switch. Staff refused, and continues to refuse, to provide any detail on that new information/data or its influence. Staff could not point to where that alleged data/information is reflected in the record, and actually confirmed that the refinery dataset utilized for the benchmarking curves in the February 26, 2014, release (that included an atypical benchmark) and the March 21, 2014, release (that has a single benchmark) were identical. ARB’s reliance on off-the-record data/information to surprise stakeholders with an eleventh hour switch to a single benchmark – overturning an atypical benchmark that was 18 months in the making and confirmed by Board Resolution – is unacceptable…

In conclusion, Kern urges the Board to delay a vote on the Proposed Amendments to ensure sufficient time to analyze this significant change in policy direction and to allow for appropriate consideration of input from stakeholders and the Board. The single benchmark currently proposed raises too many questions to be resolved in such a short period of time and stakeholders deserve better than the abbreviated and secretive process that preceded the abandonment of the atypical benchmark. Refinery benchmarking is too important to rush such a monumental change in policy direction

[240] Meeting State of California Air Resources Board Transcript, October 25, 2013, p. 32, lines 16-19.

and the consequences of getting it wrong will be devastating to stakeholders like Kern. (KERN 6)

Comment: Five years ago, the preliminary draft report came out for the cap and trade. Five months ago, we had a workshop -- I mean a Board meeting. And five minutes before the 15-day package came out, we found that the refinery benchmark had changed from two to one. So I want to note that logarithmic scale of activities. And sure, there's been lots of public process. But in the end, as Chairman Nichols mentioned, the beginning, we knew from the beginning that this last set of amendments was going to be the one that mattered.

And to go from October where there were two benchmarks for small refiners to expressly show the difference between what a large refiner is capable of and what a small refiner is capable of and go to one benchmark for multiple times, multiple documents, multiple discussions, it was all about two benchmarks. The discussion about one benchmark, there wasn't one. We were discussing between October and March one other refinery and whether they fit in the atypical category or not. We never discussed one benchmark.

In fact, if you look at the amendments – the attachments to the resolution in October, it says "direct staff to make conforming changes based on comments received." There were only comments in support of atypical benchmark. In fact, besides coalition members, the steelworkers, and environmental groups supported atypical separate benchmarking. There was no opposition and no reason to change the process at the last moment…

From a process and a precedent point of view, we had two benchmarks in the first compliance period. We had two different methodologies. And we went to one methodology, which we all agreed was probably a better way to go. But that agreement, in October, when we testified was based on the understanding there would be two benchmarks. One methodology, two benchmarks. And now we're left with one benchmark, one methodology. And that has serious consequences.

And so in closing, I would just like to say that there is more work to be done. This process got truncated at the very end. And we ask that the Board direct staff to revisit the refining benchmark as it has serious consequences on existing facilities. Thank you. (CFEA 7)

Comment: LTR is unsatisfied with the process that has occurred during the time leading up to the release of the 15-day notice. From the start of the benchmarking process, LTR has worked with the Staff to present the data and input needed to accept the concept of an atypical benchmark. …

Over the past 18 months, LTR has worked with Staff to provide the data and input needed for the development of two benchmarks, and our engagement with Staff was as recent as March 5, 2014, where we again supported an atypical benchmark.

During this time, Staff has consistently presented two benchmarks to the refining industry for review and comment, and there were no indication that Staff was considering to retract its support for an atypical benchmark (even at the March 5, 2014 meeting).

The release of the current 15-day notice is troubling because it presents an abrupt change in the benchmarking process with the removal of the entire atypical refinery benchmark.

This “closed-door” change in the refinery benchmarking proposal, calls the regulatory process into question, especially given the fact, that there were over 18 months of stakeholder activity that preceded the release of the March 21, 2014 notice.
LTR remains puzzled at how the CARB can expend the mental faculty of analyzing data, and engaging stakeholders over an 18 month process, only to completely abandon the entire atypical refinery benchmark in two weeks of “closed-door” decision making. (LTC 3)

Response: ARB staff continues to evaluate policy choices throughout the rulemaking process, and has an obligation to propose changes to the proposal as necessary. These changes may be based on direction from the Board or additional analysis and information presented to ARB staff. The Board did not formally approve the proposed amendments until April 25, 2014. The Board could have directed staff to undertake an additional 15-day notice and comment period, but did not.

As commenters have noted, refinery benchmarking has been the subject of a long process of information collection and stakeholder communication. Far from being disregarded, this process has informed ARB staff’s decision making, including the decision to use a single benchmark for refinery CWB. ARB staff has analyzed sector data and this analysis played a significant role in leading staff to settle on a single complexity-weighted barrel (CWB) benchmark. In particular, the benchmark curve accompanying the informal draft language shows the wide variation in the GHG efficiency of atypical refineries, suggesting that “atypical” refineries are not uniformly disadvantaged compared to typical refineries by the use of a single CWB benchmark. This conclusion contributed to the single-benchmark decision. ARB staff’s reasoning regarding the single CWB benchmark is discussed in response to comments B-6.8 below.

The central proposed change to refinery allowance allocation was to change from the use of CO_2-weighted tonnes (CWT) to CWB as the basis for allocation. CWB is a complex GHG efficiency metric based on extensive refinery data. Therefore, ARB staff could only consider using it after receiving a sufficiently detailed definition of CWB and comparing it to California data. ARB staff received the necessary CWB definition proposal on May 17, 2013. Only after staff received this information could staff begin to assess how to incorporate the metric into the

Regulation, which staff did in the five months between May and the October 2013 Board hearing. Additional analysis of CWB and related subtopics, such as effects on atypical refineries, was conducted between October 2013 and the April 2014 Board hearing.

As part of its analysis of the CWB proposal, ARB staff conducted a survey of California refineries to collect and understand the refinery-specific data which would be used to calculate CWT or CWB, as well as CWB-related emissions data. This survey began in June of 2013, and ARB staff continued to receive survey data corrections from refineries through late 2013. In January 2014, staff requested meetings with each refinery to check their data, and all data checks were completed before the end of February. Most refineries submitted corrections as part of this process, causing staff to need to recalculate the benchmark. As late as early February, ARB staff was still receiving data that affected the benchmark calculation.

Staff disagrees that the regulatory process has provided insufficient time and opportunity for stakeholder analysis and input. ARB staff interacted with all petroleum refineries throughout this process, and shared data and information surrounding benchmark proposals with the refineries while avoiding revealing confidential business information about individual entities. This process included ARB staff workshops dedicated to refinery, hydrogen, and calcining allowance allocation on August 13 and October 7, 2013, informal meetings with the refining sector, and numerous meetings with individual petroleum refineries.

ARB staff has released many written proposals addressing refinery allowance allocation issues. Preliminary staff thinking was presented at an August 13 workshop. As other commenters noted, policy proposals have been described in the October 7, 2013 workshop documents. More recently, the preliminary proposals were described in Attachment A to Resolution 13-44. The Board approved the resolution and directed the Executive Officer to "consider the topics set forth in Attachment A, and make such additional conforming modifications as may be appropriate and any additional supporting documents and information available to the public for a period of 15 days, provided that the Executive Officer shall consider such written comments as may be submitted during this period, shall make such further modifications as may be appropriate in light of the comments received…." Informal 15-day language was provided on January 31 in order to allow stakeholders time to respond before the final formal 15-Day Modifications were released. Substantive refinery-related changes made after the informal draft were communicated verbally to affected stakeholders prior to the formal 15-Day Modifications release. Formal 15-day language was released on March 21, 2014.

ARB staff communicated with stakeholders throughout this process. ARB staff was available to meet, although in some cases staff informed stakeholders that it had no new information to share because it would be improper to share a policy proposal with any one stakeholder before making it publicly available to all stakeholders. This occurred with stakeholders with whom staff had met on multiple prior occasions. Staff has met with every stakeholder who expressed interest in the refinery benchmarking process.

Opposition to Refinery Benchmark

B-6.4. Comment: The proposed benchmark of 3.89 allowances per CWB for refineries is too low. Based on data prepared by Solomon in response to ARB questions, if the 2008-2010 emissions from refineries are about 31.5 million metric tons, and assuming a 90% stringency (consistent with ARB policy), a benchmark of 4.08 allowances per CWB appears to provide the appropriate amount of allowances. (WSPA 5)

Comment: We think that the refinery benchmark still is a little low. We'd like to suggest a process by which that refinery benchmark could be trued up…

The reporting and benchmarking must be on a consistent basis. We encourage a process to true-up and resolve inconsistencies in both the refinery and hydrogen plant benchmark.

And we'd like to ask the ARB and the staff is there any way they can see to identify a process to allow us to continue to work collaboratively on the benchmark so we can keep good dialogue going and get to the right answer. (WSPA 6)

Response: ARB staff believes the refinery benchmark is accurately calculated based on the 2008 and 2010 data provided by refineries. The total emissions from this sector for the 2008 and 2010 data years were 49,452,702 MT CO_2e and the total CWB was 11,429,282 CWB. Thus, when the benchmark is set at 90% of the sector average, the correct benchmark is 3.89 allowances per CWB. The total sector emissions were provided to ARB under MRR and were adjusted to include emissions from imported steam and exclude emissions from exported steam and electricity. In addition, emissions from coke calcining and hydrogen production were excluded because those activities receive free allowances under separate benchmarks. Following ARB's general benchmarking principles, emissions and CWB data from one refinery with abnormal operation during the data years were not used in the benchmark calculation. ARB staff thoroughly reviewed CWB data with representatives from each refinery to ensure accurate and consistent reporting across the sector. Staff believes that the 3.89 allowances per CWB benchmark is accurately calculated and based on sound data.

CWB Reporting Process

B-6.5. Comment: WSPA members continue to work with ARB as we collectively gain understanding of reporting requirements. Certainly, with the April, 2014 deadline already upon us, these requirements become even more important. The task of reporting for 2014 and beyond may become more complicated as companies begin reporting using guidance ARB is still developing for the Complexity Weighted Barrel (CWB). As can be expected when dealing with reporting from complex facilities, challenges associated with issues such as data gaps, intermittent meter malfunctions, alternative measurement methods, and postponement requests, will emerge from time to time.

Recommendation: WSPA recommends ARB continue to work with stakeholders to review options for addressing infrequent, but nonetheless expected, events that result in data gaps or meter calibration challenges, while still allowing companies to receive unqualified positive verifications. (WSPA 5)

> **Response:** This comment is outside of the scope of 15-Day Modifications so no response is required. The requirement for petroleum refineries to report CWB data was part of 2013 modifications to MRR. ARB staff notes that the refinery reporting deadline for MRR was extended to May 16, 2014, to allow for reporters to adjust to the first year of reporting of new product data.

Complexity Weighted Barrels vs. Simple Barrels

B-6.6. Multiple Comments: CWB As a Proxy for Production

The CWB methodology measures a surrogate product - it does not account for true real product manufacturing efficiency. CWB is a synthetic measurement of a refinery's "product," BUT a refinery's emissions on that product is affected by that refinery's size and complexity. And, although the high energy intensity processes of large refineries can be efficient, they are not manufacturing real products like gasoline and diesel fuel as efficiently as the smaller refineries in the state because of the high energy intensity of their selected processes.

We believe our Paramount Refinery is the most CO2 emission efficient refinery in California at manufacturing real products (gasoline, jet fuel, diesel, and asphalt) under the primary product barrel approach. The refinery has operated at 20% to 40% below the first compliance period product benchmark of .0462 MT/product barrel. However under the CWB methodology it is the least efficient refinery for manufacturing Complexity Weighted Barrels, where during the same two years it operated at 40% to 95% above the proposed benchmark of 3.89 MT/CWB. Clearly something is wrong with the CWB methodology as proposed by CARB. We believe that the amount of energy required to produce a product barrel is a more realistic benchmark than the CWB and is consistent with the methodology used in other industries…

Is it equitable and logical policy to place this magnitude of burden on the smallest manufacturers of this sector to achieve relatively very small results using an artificial measure of efficiency (MT/CWB), when on a real product based measure (MT/BBL) similarly used by all other sectors, they are very likely the most efficient manufacturers of product in that sector? Shouldn't the proper policy reward and encourage efficiency by this ultimate measure rather than punish (and maybe eliminate) these manufacturers?...

ARB previously abandoned a single simple barrel approach (2010 benchmarking) because of similar detrimental impacts to individual facilities and selected a two-tier approach. That approach was precedential and should be followed again now with the reinstatement of the Atypical benchmark. Atypical refineries should be given the option of electing to use the Simple Barrel methodology. (PARAMOUNT 4)

Comment: The very recent decision to eliminate the atypical refinery category and establish single complexity weighted barrel benchmark for this industry is a significant financial blow to our plans to restart our facilities.

Next slide, please. [Paramount presented slides at the Board hearing that are included in the comments but cannot be reproduced in this document.]

This slide shows data that CARB staff collected while developing industry benchmarks built. Metric used is CO2 emissions per barrel of primary product. Paralleling the product-based benchmarks of other industrial sectors, each dot on the graph is a refinery.

Our Paramount refinery, the red diamond in the lower left-hand corner is the most CO2 efficient refinery in California for manufacturing real products. When operating, it was 20 to 40 percent below the benchmark of this approach and can be considered the model low CO2 refinery.

Since the large refineries in California use much more energy intensive-processes to convert the heavy part of the barrel into fuel, their operators do not like this product-based metric and pushed for alternative artificial process-based metrics, such as complexity-weighted barrels which obscure and hides product efficiencies.
Next slide, please.

This is a view of California refinery efficiencies under the CWB metric. Note under this view of the world, our Paramount refinery is the least efficient refinery.

On the far right side, it's hard to see in that light, but the top right corner is our refinery now. We went from the very best to the very worst. Clearly, something is wrong with the CWB methodology as proposed.

Shifting to a single CWB benchmark would require the Paramount refinery and at least two other small refineries to reduce emissions by 40 to 50 percent just to meet the benchmark level at a cost more than a million dollars per refinery per year. This is a large financial burden.

Is it equitable and logical to policy to place this magnitude of burden on the smallest manufacturers of this sector to achieve relatively small results using an artificial measure of efficiency, when on a real product-based measure used by other industrial sectors, they are the most efficient manufacturers of their product? Shouldn't the proper policy reward encourage efficiency by this ultimate measure, rather than punish these manufacturers?

We have never manufactured a barrel of CWB, nor has anyone else. We'd like to make real barrels of gasoline, jet fuel, diesel and asphalt again for California in the near future and our efficiency by that measure is what we think is the fairest to judge us on. Thank you. (PARAMOUNT 5)

Comment: ARB previously abandoned a single simple barrel approach (2010 benchmarking) because of similar detrimental impacts to individual facilities and went with a two-tier approach. That approach was precedential and should be followed again now with the reinstatement of the Atypical benchmark. (CFEA 6)

> **Response:** In the first compliance period, the Regulation utilized an allocation approach that relied upon the Solomon Associates Energy Intensity Index® values for those refineries which have them, and primary product barrels for other refineries. ARB staff has now had time to analyze and adopt a more appropriate approach based on CWB, a metric which was proposed by the Western States Petroleum Association and endorsed, prior to these 15-day comments, by all refineries in California.[241] ARB staff believes the CWB approach better allots allocations for petroleum refinery production.
>
> The primary refinery product allocation method employs a single benchmark based on the addition of barrels of disparate products, including gasoline, diesel, jet fuel, and asphalt. These products differ in their market value, typical uses, and the amount of energy and GHG emissions required to produce them. For example, asphalt requires much less emissions to produce, on average, than gasoline. This makes asphalt-focused refineries appear more GHG-efficient than gasoline-focused refineries under the primary product approach. This may explain the differences in emissions intensity calculations identified by the commenter.
>
> Ideally, each refinery product would receive a separate benchmark. However, neither ARB staff nor the refineries have data that allow ARB staff to assign emissions intensities to each of these products precisely enough to take this approach.. However, CWB effectively sets separate benchmarks for separate refinery processes. As a result, products which require more processing or processing that is more emissions intensive will receive higher allocations. In this way, the CWB method takes into account the different emissions intensities of different products. ARB staff therefore believes that a CWB benchmark better

[241] Support from WSPA, CFEA (which includes all non-WSPA refineries), and most individual non-WSPA refineries is expressed in the 45-day comments. See 15-day responses, comments B-6.1 and B-6.2. Similar support was also expressed in meetings with ARB staff.

approximates the traditional one product, one benchmark benchmarking approach than a simple barrel benchmark.

Further discussion of how benchmarking relates to "atypical" refineries, including financial burden variation among refineries, is discussed in response to 15-day comment B-6.8 below.

Asphalt

B-6.7. Comment: Lastly, Alon has continually raised the issue of the uniqueness of Asphalt refineries and how they could be addressed under the Cap and Trade regulation in general, and specifically under the CWB methodology. These issues have been discussed, but were "left off the table" due to limited staff resources, regulatory timing, and other higher priority considerations. Alon accepted that only so much could be squeezed into this regulatory package, but we are concerned when stakeholder issues are pushed to future regulatory packages yet significant CARB-proposed late revisions are allowed to be introduced. Alon looks forward to continuing the discussion about how the Cap and Trade Regulation effects in-state asphalt production facilities and particularly the impact of ignoring their inherently real refined product barrel efficiency. (PARAMOUNT 4)

Response: Asphalt production has a process unit factor under CWB, which means that asphalt production will be used to calculate allowance allocations. ARB staff has received no comments asserting that the asphalt process unit factor is inappropriate, and it would be difficult to reconsider this process unit factor without reconsidering all aspects of CWB. Some further responses regarding asphalt are provided in response to 45-day comment B-8.4 in Chapter IV.

Opposition to a Single Refinery CWB Benchmark

B-6.8. Multiple Comments: There is always a range of refinery efficiency no matter the size. Some overlap between the most efficient atypical refinery and the least efficient typical refinery was to be expected. Indeed, from the inception of Staff's recommendation for two benchmark, there has been overlap between the Atypical and Typical groups (i.e., among the most efficient Atypical refineries and the least efficient Typical refineries). Therefore the recent discussion in Appendix A—Additions and Amendments to Product- Based Benchmarks in the Cap-and-Trade Regulation which states that "some smaller and less complex refineries are among the most emissions efficient (in relation to CWB throughput)" misses two key facts: 1) those two refineries are mainly asphalt refineries and do not produce CARB gasoline, 2) the two worst performing refineries (and those impacted the most) are the State's smallest gasoline-producing facilities. Variation in a sub-group of refineries does not negate any single facility's position as Atypical, nor does it justify a single benchmark. What staff fails reference or account for is the fact that the two worst performers in the industry are in fact smaller, less complex Atypical facilities.

Staff's release also erroneously overstates the value of the CWB methodology in accounting for the size and complexity of a facility for benchmarking purposes. The CWB methodology measures a surrogate product - it does not account for efficiency limitations. CWB is an accurate measurement of a refinery's "product," BUT a refinery's emissions per product is affected by that refinery's size and complexity. Staff's Appendix A released with the Proposed Amendments erroneously expresses the ability of the CWB methodology to account for facility size and complexity in benchmarking. The CWB accounts for these differences in determining a common, single product; however, appropriately comparing facilities for benchmarking is a separate and distinct exercise. By way of example, some of our members were among the most efficient refineries under the simple barrel approach and now are some of the least efficient refineries under CWB methodology. Solomon (the creator of CWB) stated at the August 13, 2013, workshop that accuracy of the CWB is irrelevant as to whether Atypical refineries should be separately benchmarked and gave an example of how this is true. By nature of the structural constraints highlighted by Solomon, in general smaller, less complex refineries cannot achieve the scores that larger, more complex refineries, thus the need for an Atypical benchmark.

A single benchmark creates winners and losers. Shifting to a single benchmark would require certain Coalition Members to reduce emissions by 40% just to meet the benchmark level (90% of the average statewide refinery efficiency). This is unrealistic, as ARB's own energy audit found reduction potential at individual facilities to be below 10%.

ARB previously abandoned a single simple barrel approach (2010 benchmarking) because of similar detrimental impacts to individual facilities and went with a two-tier approach. That approach was precedential and should be followed again now with the reinstatement of the Atypical benchmark. (CFEA 6)

Comment: CARB's use of single one-product benchmark for the refining sector is arbitrary and inconsistent with other sectors within the Cap and Trade Program.

Phillips 66 opposes the methodology that CARB has selected for refinery benchmarking and believes such methodology conflicts with the goals stated in the initial legislation AB 32 and the goals stated in the Scoping Plan. The benchmark is punitive and not designed to reward energy efficiency or innovation. (PHILLIPS 6)

Comment: Kern urges the Board to reject the Proposed Amendments and direct staff to reinstate the atypical refinery benchmark in a subsequent 15-day package to be considered at a later Board Meeting…

Testimony provided by worldwide acknowledged refining expert Solomon Associates (Solomon) and Ecofys at an ARB workshop held August 13, 2013, proved to be a turning point in the proceeding. Solomon and Ecofys clarified that the "atypical" issue is not related to a failing with the Complexity Weighted Barrel (CWB), which is merely an artificial stand-in for product. CWB is an accurate measurement of a refinery's “product,” but a refinery’s emissions per product (i.e., efficiency) is affected by that refinery’s size and complexity. Per Solomon “smaller and simpler (i.e., a lower complexity) refineries tend to have poorer energy efficiency, for reasons such as limitation on economy of scale and fewer streams of feed and products and therefore less heat integration and exchange opportunities for energy saving and optimization.”242 Smaller, less- complex refineries therefore cannot reach the efficiencies of super refineries. In every Solomon- involved benchmarking worldwide, each region has had its own particular “atypical” refineries.243…

On the record, staff provides three alleged justifications for abandoning the atypical benchmark: (1) the data demonstrates that CWB does not overestimate atypical refineries’ emissions intensity because “CWB normalizes for size, complexity, and product mix at refineries”; (2) that “some smaller, less-complex refineries are among the most emissions efficient … in the State”; and (3) the wide variance of the emissions intensity of smaller, less complex facilities.244 These statements are countered by the record in this proceeding and take data out of context. Regardless, ARB’s ability to utilize identical data to justify completely opposite policy positions is not credible...

1. CWB Does Not Normalize for Atypical Size and Complexity Efficiency Limitations.

The supporting documentation released with the Proposed Amendments confuses quantifying refinery product with CWB versus setting an appropriate benchmark. The CWB methodology measures product – it does not account for efficiency limitations. Appendix A erroneously suggests CWB accounts for facility size and complexity relative to benchmarking. CWB accounts for these differences in determining a common, single product; however, appropriately comparing facilities for benchmarking is a separate and distinct exercise. CWB is an accurate measurement of a refinery’s “product,” but a refinery’s emissions per product is affected by that refinery’s size and complexity. Solomon (the creator of CWB) stated at the August 13, 2013, workshop that accuracy of the CWB is irrelevant as to whether atypical refineries should be separately benchmarked. An example was given that a glass factory can have an accurate CWB score but still could not be fairly compared to a refinery’s CWB.

By nature of the structural constraints highlighted by Solomon, in general, smaller, less complex refineries cannot achieve the top efficiency of larger, more complex refineries; conversely, atypical refineries have a much lower efficiency starting point than typical refineries. In other words, the best performing typical refineries can reach an efficiency level that is unachievable by atypical refineries and the worst performing atypical refineries start at a much lower efficiency level than the worst performing typical refineries. The California data set is only a limited demonstration of these points, which are more strongly illustrated on a national or worldwide scale. In addition, the best

[242] August 6, 2013, Solomon Response to ARB Questions, pp. 1-2.
[243] Ecofys, ARB’s expert, when advising ARB to consider and address the issue of atypical California refineries in its August 28, 2012, report, cited to the European Union as an example of a region that dealt separately with atypical refineries; however, obviously, what may have represented an atypical refinery in Europe does not determine what may be an atypical refinery in California.
[244] Proposed Amendments, Appendix A: Additions and Amendments to Product-Based Benchmarks in the Cap-and- Trade Regulation, March 21, 2014, p. 17.

performing California atypical refineries can also be differentiated from their atypical California peers on the basis of product slate, as discussed below.

2. Both Atypical and Typical Refineries Have a Range of Efficiency That Have Always Overlapped.

Without dispute, there is always a range of refinery efficiency, no matter the size, and some overlap between most efficient atypical and least efficient typical is expected. From the inception of staff's recommendation for two benchmarks, there has been overlap between the atypical and typical groupings (i.e., among the most efficient atypical refineries and the least efficient typical refineries). This overlap is apparent in every benchmarking curve that ARB has published since October 2013 and staff nonetheless continued to recommend separate benchmarks until very recently. The reliance on the presence of efficient atypical refineries that overlap with the efficiency of typical refineries to justify a single benchmark also misses two key facts: 1) those two refineries are mainly asphalt refineries and do not produce gasoline, which may account for their efficiency differences; and 2) the two worst performing refineries (and most detrimentally impacted) are the State's smallest gasoline-producing facilities. Variation in a sub-group of refineries does not justify a single benchmark…

A single benchmark creates winners and losers. Shifting to a single benchmark would require certain Coalition Members to reduce emissions by 40% just to meet the benchmark level (90% of the average statewide refinery efficiency). ARB's own report demonstrates emissions reduction potential at individual facilities to be below 10%.8 Clearly requiring a reduction of 40% is unrealistic. ARB previously abandoned a single simple barrel approach (2010 benchmarking) in favor of a two-tier approach because of similar detrimental impacts to individual facilities. ARB has always had difficulty in assigning a single benchmark to the refinery sector because of the wide variance in facilities and the detrimental impact that would result. Those difficulties have not been alleviated by the current proposal; in fact, certain refineries are facing worse detrimental impacts under this proposal as compared with those impacts that prompted ARB to abandon a single benchmark in the first compliance period. One size does not fit all in the refinery sector and the proposed single benchmark threatens the viability of California's smaller, less complex refineries. (KERN 6)

Comment: Formal recognition and separate benchmarking of "atypical" refineries in the Cap and Trade Program is a key policy recommendation Alon supports. Not all refineries in California are large and complex, and not all of them are of a simple single site configuration; the previously defined atypical category appropriately recognized this reality. What defines a refinery as being "atypical" is certainly regional in nature; therefore it is entirely appropriate to establish criteria for an atypical California refinery based on the state's existing inventory of refineries. Alon supported the proposed California-specific atypical criteria metrics of less than 12 process units and 20 million barrels of crude throughput per year. Staff's removal of this category is a very significant POLICY change at the end of a long regulatory process...

In addition, Solomon Associates (the creator of CWB) stated at the August 13, 2013 workshop that by nature of the structural constraints, the smaller, less complex refineries cannot achieve the CWB efficiencies of larger, more complex refineries, thus the need for an Atypical benchmark. Because two of the small refiners in California can meet the CWB benchmark efficiency level does not indicate that all of the atypical refiners can achieve the same. This is the result of their configuration and product mix. Neither of these two refineries is a gasoline manufacturer with one producing exclusively asphalt products and the other producing asphalt, solvents, lubes, and specialty oils (transformer and ink oils), with a very small CARB diesel capability.

A single benchmark creates big winners and losers. Shifting to a single CWB benchmark would require the Paramount refinery and at least two other small refineries to reduce emissions by 40% to 50% just to meet the benchmark level (90% of the average statewide CWB efficiency). This is a large financial burden, unrealistic and is very likely economically unachievable. (PARAMOUNT 4)

Comment: We'll show that -- members behind me will show how this impacts their facility directly. But the data that we have shown that two benchmarks were acceptable. And there is a multiple digit difference between what it was and what it combined down to. So it's an important aspect to know that this is a real issue for the small refiners. (CFEA 7)

Comment: As Mr. Grimes pointed out, under the simple barrel approach, Paramount was the most efficient. Under the CWB, we're the least efficient. Both methodologies use synthetic measures of efficiency and give different weights to different processes. While I'm not sure if Paramount was the most efficient refinery in California, I clearly believe it's not the least efficient. Next slide. [Paramount presented slides at the Board hearing that are included in the comments but cannot be reproduced in this document.]

Many of you have seen this slide before. Each bubble represents a refinery. The larger the bubble, the more the carbon dioxide emissions.

Paramount is happy to do its share to reduce greenhouse gas emissions. We are the second bubble to the left-hand side. Smallest bubbles.

Based on the proposed regulation, we will be required to reduce 50 percent of our CO2 emissions. Most other refiners are only required to reduce ten percent. Staff has indicated that only a ten percent reduction is feasible. Requiring Paramount to reduce and purchase credits of GHGs to 50 percent places us at a significant environmental disadvantage.

While it is especially true in light of the fact that our emissions represent -- ours and Kern's represent less than three-quarters of one percent of the total sector emissions, Paramount respectfully requests that the Board direct staff to review and develop a second benchmark for fuel producing atypical refineries. (PARAMOUNT 6)

Comment: I'm here this morning -- or this afternoon to speak to you specifically regarding refinery benchmarking and to specifically ask the Board to separately benchmark atypical transportation fuel producing refineries. Those refineries that produce CARB reformulated gasoline and those refineries that produce CARB number two ultra low sulfur diesel fuel.

Chairman Nichols, your comments earlier are well spoken and well received. Initially, our approach, our focus on size, on complexity, on benchmarking did involve at least four refineries. It did involve -- of those four, two were asphalt refineries. And those asphalt refineries quite frankly proved to be display efficiencies that caused comparisons to be the kind of comparison frankly that may not have been apples to apples in nature. They muddied the water. They clouded the issue.

However, it was clear throughout the process that the transportation fuel refineries and particularly Kern and Alon are refinery sector outliers and that the one benchmark would require these refineries to reduce emissions by at least by more than 40 percent, a requirement that is unattainable. We cannot -- we simply cannot do that. Benchmarking matters. Size matters. And that is one of the things that we have focused on and pressed on and discussed over and over.

Small refineries have opportunities for less heat integration, less exchange opportunities. We do not possess the economies of scales of bigger refineries. In the big picture, let me speak particularly and quickly to Kern.

Our emissions account for only .6 of one percent of the refinery sector's emissions, while the three largest refinery sector emitters in California account for more than 50 percent. If -- and you can't do this, as I stated earlier -- if you were to lower Kern's emission by 40 percent, it would reduce the refinery sector's overall total emissions by only one quarter of one percent.

Kern is one refinery in Bakersfield. We produce -- we're the only producer of reformulated gasoline and diesel fuel between Los Angeles and the Bay Area.

So in closing, let me state three items:

Number one: The one benchmark scenario, the reality is it presents negative financial impact on our company that is unsustainable.

Number two is we're not asking for an opt-out. We're not asking for an exemption. What we're asking is for a realistic place in your Cap and Trade Program.

And to conclude, I will simply ask this to be specific. We would ask that the Board clearly direct staff to provide a separate, a fair, and equitable benchmark for atypical transportation producing, transportation fuels, gasoline diesel producing refineries to be defined as, one, a refiner that produces CARB reformulated gasoline; CARB number two ultra low sulfur diesel fuel; possesses operates twelve -- less than twelve units in its refinery; and processes less than 20 million barrels of crude oil per year. (KERN 7)

Comment: LTR has and continues to support two refinery benchmarks (i.e., typical and atypical). (LTC 3)

> **Response:** ARB staff has determined that the use of only one CWB benchmark for all refineries rather than benchmarking "typical" and "atypical" refineries separately is most appropriate. Comments most directly addressing this issue are discussed here. In the interest of clarity, further comments made in opposition to a single benchmark have been sorted into separate comment categories: process objections are addressed under response B-6.3, comparison to a simple barrel benchmark is addressed under response B-6.6, input from consultants is addressed under response B-6.9, and data use objections are addressed under response B-6.10. Chapter IV includes additional discussion of asphalt in response to 45-day comments B-8.4.
>
> Counter to the assertion of one of the commenters, the Cap-and-Trade Regulation does not require that any one facility achieve a certain level of emissions reduction. Compliance can be achieved by any combination of emissions reductions and compliance instrument procurement that results in meeting compliance obligations.
>
> Cap-and-Trade Program benchmarks generally compare facilities within a sector by allocating based on output within categories defined by product type, not by using size-based categories or adjusting for possible economies of scale. This is the means by which the Cap-and-Trade Program provides equitable incentives for emissions reductions. Commenters have mentioned that refinery efficiency may correlate with size and complexity, and that use of one benchmark may create winners and losers. Staff has endeavored to communicate to stakeholders that efficiency variation alone is not a justification for separate benchmarks. Facilities that are less efficient than the benchmark can meet their compliance obligations by purchasing allowances rather than by reducing emissions, if they so choose. This flexibility is central to the concept of a cap-and-trade system. In this way, no one facility is forced to meet the benchmark level, but the emissions cap is maintained and the total costs of compliance are minimized.
>
> In the refining sector, an exception to the "one product, one benchmark" concept was considered because of the nature of CWB as a proxy for production. In theory, CWB should accurately reflect the typical emissions associated with a given product mix and only one benchmark should be needed. However, ARB staff was concerned that CWB may overestimate the emissions intensity of small, simple, "atypical" refineries, which were not part of the industry organization which proposed CWB or the data set Solomon used to define CWB. Therefore,

staff analyzed this possibility by examining the CWB-based emissions intensities of each refinery.

The results did not suggest that CWB under allocates to small California refineries; in fact, the opposite may be true. Some small refineries are among the most efficient in the State when measured in emissions per CWB. In particular, the CWB includes adjustments based on refinery inputs. These adjustments are the “off-sites” and “non-crude sensible heat” factors mentioned by one of the commenters. Since smaller, simpler refineries conduct less processing per unit input, these adjustments have a larger effect on smaller refineries. These adjustments play a substantial role in decreasing the apparent emissions intensities of smaller refineries, effectively adjusting CWB based on size. Also, some simpler refineries may benefit from CWB because CWB assumes they use their atmospheric crude distillation units more intensely than they do. That is, the design of CWB may actually favor small refineries. Therefore, ARB staff concluded that using CWB does not create a need for separate “typical” and “atypical” benchmarks.

Regarding the comment about gasoline vs. asphalt producers, ARB staff cannot release information that would identify which refineries are represented by which points on the graph. Asphalt production is included as a process unit when calculating CWB. In general, it is certainly possible that California’s small, gasoline-focused refineries have different efficiencies than its small asphalt-focused refineries. If asphalt-focused refineries in general fare better or worse under CWB than gasoline-focused refineries, this may indicate that CWB favors one product over another or that the CWB factor values are not appropriate, and might suggest that it would be valuable to reevaluate CWB. However, the small number of California refineries would make such evaluation difficult. In any case, it is unclear to ARB staff why a difference between small asphalt and small gasoline producers would suggest that they should be categorized together as “atypical.”

Rather than include asphalt producers in an “atypical” category, one commenter has proposed an “atypical” benchmark for only small refiners which produce transportation fuels. This would be contrary to the “one product, one benchmark” policy.

External Advice Regarding Atypical Benchmark

B-6.9 Multiple Comments: Smaller, less-complex refineries cannot be fairly compared to larger more complex “Typical” refineries. Industry expert Solomon Associates “has found that smaller and simpler (i.e., a lower complexity) refineries tend to have poorer energy efficiency, for reasons such as limitation on economy of scale and fewer streams of feed and products and therefore less heat integration and exchange opportunities for energy saving and optimization” (August 6, 2013, Solomon Response to ARB Questions, p. 1-2). Additionally, Solomon testified that Atypical refineries have been identified in every benchmarking process that they have participated in around the world and that smaller refineries cannot be fairly compared to “super” refineries (August 25, 2013, Workshop, Solomon Testimony). (CFEA 6)

Comment: We are also disappointed with the decision to abandon the “atypical” benchmark in light of the recommendations rendered by the CARB's own consultant–the industry expert in refinery benchmarking. The establishment of two benchmarks is a key policy decision that not only incorporates the recommendations of leading benchmarking experts, but input from affected stakeholders…

In the fundamental sense, an external consultant offers invaluable benefits to their clients due to the deep domain knowledge of their own expertise.

During the benchmarking process the CARB retained the industry expert in refinery benchmarking, Solomon Associates (“Solomon”). Retaining Solomon is a prudent decision because it integrates objectivity, as well as their extensive knowledge of refinery benchmarking, into the regulatory process for California’s Cap-and-Trade program.

In August 2013, Solomon testified that atypical refineries have been identified in every benchmarking process that they have participated in around the world. Nevertheless, the current proposal, that eliminates the atypical refinery benchmark, runs counter to the testimony of the industry expert in refinery benchmarking, and ultimately calls the entire decision for a single benchmark into question.

Again, LTR remains puzzled at how the CARB can ignore the advice from their own consultant–the industry expert in refinery benchmarking–by abandoning the atypical benchmark. (LTC 3)

Comment: On August 28, 2012, ARB’s own expert Ecofys suggested ARB consider separately benchmarking Kern and other “atypical” refineries.[245] (KERN 6)

> **Response:** ARB staff wishes to first clarify ARB’s relationships with entities mentioned by the commenters. ARB is not a client of Solomon Associates. The Western States Petroleum Association (WSPA) is a client of Solomon Associates. WSPA has retained Solomon for the purposes of advocating for the use of CWB in the Cap-and-Trade Regulation. While Solomon Associates employees may have extensive refinery-related expertise and have testified at ARB staff’s workshop on October 7, 2013 at staff’s request, ARB did not pay them to do so.
>
> Ecofys is a consulting agency which has been retained by ARB to assist with assessing benchmarking options, including for refineries.

[245] August 28, 2013, Ecofys Preliminary Work Product, p. 44 “Exclusion of Atypical Refineries”; p. 45 “Table 11: Potentially atypical refineries together with indication for not being a ‘mainstream’ refinery”.

Neither Solomon Associates nor Ecofys have specifically recommended to ARB staff whether or not there should be a distinct category for small refineries under California's Cap-and-Trade Regulation. As consultants, they have answered factual questions from ARB staff regarding how "atypical" refineries have been defined and treated in other jurisdictions. Their input focused on the technical aspects of refining while leaving policy decisions to the judgment of ARB staff in light of the intended design of the Cap-and-Trade Program.

Data Used for Previously Proposed Atypical Definition and Benchmarks

B-6.10. Multiple Comments: ARB's supporting documentation highlights that one refinery had abnormal operations in 2008, and therefore was excluded from the benchmarking calculation. In fact, that particular Coalition member facility actually had normal operations in 2008, but has subsequently had a temporary change in its operational status. Though it was known that that refinery would have fit into the Atypical category, the particular refinery (a Coalition member) did not object to this data omission from in the benchmark as it was deemed not necessary given that two benchmarks that had been proposed. Given the reversal in policy, this data exclusion has become material as it supports the need for an atypical benchmark. In fact, when included, this data point demonstrates further the distinction between the proposed Atypical and Typical benchmark values.

Similarly, Staff omitted data for another Coalition member facility from the Atypical analysis that would have further supported the need for an Atypical benchmark Staff intentionally considered this facility's data point among the Typical refinery data set simply because the facility does not itself produce finished fuels, despite otherwise meeting proposed Atypical qualifications (an ongoing robust discussion of this issue, i.e., "jointly operated," was rendered moot when the revised single benchmark was released). Consideration of that data and inclusion of the "abnormal" facility in the Atypical category further supports the need for the category (i.e., the efficiency limitations of atypical refineries) and again would have increased the previously proposed benchmark. Staff selective consideration of data and failure to use data which supports the need for an Atypical benchmark is troubling – especially given the extremely limited number of Atypical data points that remain – a mere four facilities. The plot of Atypical refinery data looks much different with six data points, rather than just the narrower set of four points utilized by Staff, demonstrating a more continuous curve in the Atypical group.

The final manipulation of data and lack of transparency regarding two week reversal of established policy is also very concerning. Staff has not disclosed what "new information/data" was used to make the final policy determination. But they have confirmed that the benchmarking curve shown in Figure 1 of the February 26, 2014 refinery document (Attachment G) is identical to the one included in Figure 6 of the attachment to the Proposed Amendments. It is unclear how identical data can reverse firmly established policy, which relied on 18+ months of intense stakeholder and expert dialogue versus two weeks of behind closed doors analysis by ARB staff without any stakeholder or expert input. Therefore, the Coalition strongly requests that official administrative record contain any new information used to establish Board policy. [The attachments mentioned by the commenter are not included here, but are part of the regulatory record.] (CFEA 6)

Comment: The Alleged Wide Variance in Atypical Category Efficiencies is Exaggerated by Exclusion of Pertinent Data Points.

ARB's supporting documentation in Appendix A to the Proposed Regulation highlights that it excluded one refinery's data from the benchmarking calculation because of abnormal operations in 2008. That particular facility however actually had normal operations in 2008, but has subsequently had a change in its operational status. Though that refinery would have fit into the atypical category, the particular refinery (a Coalition member) did not fight for its inclusion given staff's proposal for an atypical benchmark. Given the policy reversal and staff's stating reasoning for a single benchmark (the alleged wide efficiency variance in atypical group), exclusion of that facility is material because it supports the need for an atypical benchmark and in fact would have increased the previously proposed atypical benchmark. Another Coalition member submitted updated data to demonstrate one of its facilities belonged in the atypical category but the data was not included in the benchmarking calculation. Consideration of that data and inclusion of that facility in the atypical category would further support the need for the separate benchmark (i.e., the efficiency limitations of atypical refineries) and, again, would have increased the previously proposed atypical benchmark. Staff's selective consideration of data and failure to use data which supports the need for an atypical benchmark is troubling – especially given the extremely limited number of atypical data points that remain – a mere four facilities. (KERN 6)

All of Alon's facilities (Bakersfield, Edgington and Paramount) would have been classified as "Atypical" yet CARB staff only used the combined data for the Paramount/Edgington facilities when determining the benchmarking policy. This is a significant oversight, especially given how few data points are available. Leaving out Bakersfield's data amounts to not including 20% of the potential data points in the Atypical category. Although the Edgington facility had minimal operations in 2008 or 2010, Bakersfield operated in its historic mode for the full year 2008. Its data should be considered in the data used to construct the policy analysis, and not considered "abnormal". If Alon would have known that a last-minute policy change was to occur and the rationale for it was that the Atypical data set didn't support it, we certainly would have insisted CARB include our data. But after five months, an adopted Board Resolution (13-44) and several staff released versions of new documents, all which showed two benchmarks, Alon was surprised by the policy reversal…

In addition, how this lower single benchmark will impact the viability of either the new "Renewable Diesel Refinery", or other commercial refining options, potentially collocated at the Paramount facility are unknown. To further complicate the issues, our long-term planning could include using our Long Beach facility in these new activities.

Loss of the Atypical status for any of these facilities could have serious economic impacts. Recent conversations with your staff have confirmed that additional discussion and evaluation of the myriad of impacts is necessary as the regulation is rigid in its treatment of refineries and does not address unique operations. Alon will continue to work with staff to fully describe potential operating scenarios. But any such discussions should not impact benchmarking policy, which should be based on historical operations. (PARAMOUNT 4)

Comment: We remain opposed to certain elements of the new 15-day package. Specifically, 1) the cap adjustment factor for coke calcining is incorrect, 2) hydrogen plants efficiency benchmarks are incomplete and 3) the use of a single one-product benchmark for the refining sector is arbitmty and inconsistent with other sectors. (PHILLIPS 6)

Response: In the calculations regarding atypical refineries, ARB staff included all refineries which were in operation in 2008 and 2010 and met the definition of atypical using their data from those years. ARB staff's tentative definition of "jointly operated" was employed. ARB staff believes this choice of data is as equitable as possible. As the commenters have noted, ARB staff excluded the data from one refinery that did not meet these criteria. ARB staff does not know if its 2008 operations were likely to be representative of later years' operations as a "typical" vs "atypical" refinery, since the facility is making equipment changes. EIA capacity data indicate it would be typical if operating at capacity, but it may operate below capacity. Therefore, ARB staff determined that the most appropriate approach is to exclude both years of data from that facility.

As commenters noted, this facility's owners were long aware of this data exclusion and have not previously expressed any disagreement. During the process when all other facilities' data were reviewed, that facility declined to review and confirm their data with ARB staff because of the mutual understanding that staff was not planning to make use of that facility's data.

When ARB staff was considering a separate "atypical" benchmark, the definition of joint operation was part of that proposal. Conceptually, this definition would have considered refineries which produce little saleable product of their own to be jointly operated with the refineries that receive and complete the processing of their partially-processed output. In such cases, equipment at separate geographic locations is effectively operating as a single refinery which receives crude oil and produces product. Since joint operation was part of the atypical policy proposal, ARB staff considered it appropriate to take joint operation into account when analyzing the issues surrounding "atypical" refineries and to report its data analysis accordingly.

ARB staff has not received additional data demonstrating that any other refinery ARB staff classified as "typical" is actually "atypical." Staff received a request to reclassify a typical refinery as atypical, but received no new data or clear justification for the request.

ARB is custodian of confidential business information. As such, there are significant limits on what information ARB can release to the public. In some cases, this means that ARB cannot release all of the information which would help stakeholders understand its decision making. Staff is aware of this tension between transparency and protection of confidential business information.

Refinery True-Up for First Period

B-6.11. Comment: §95891(d)(2)(B)- True-up Debit. This section applies to the first compliance period years 2013 and 2014. The True-up calculation specified in this section will occur after data verification is completed in September 2015. It appears that year "t" in this equation refers to either year 2013 or 2014 (this conclusion is drawn based on the definition of $AE_{y,t}$). The True-up Debit definition states this value of allowances for budget year "t" shall be allowed to be used for budget year "t-2". However, if "t" is 2013 or 2014, then the true-up debit is allowed to be used for budget year 2011 or 2012, which does not make sense. If "budget year t" is intended to be 2015 (the year True-up debit is calculated), then it can only be used for budget year 2013 which still does not make sense because this is a combined calculation for both years 2013 and 2014. We suggest the following changes:

Recommendation: "True-UpY,Debit" =the amount true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations for refinery "Y". This value of allowances for budget year "t 2015 or 2016" shall be allowed to be used for budget year "t-2 2013 or 2014" pursuant to 95856(h)Cl)(D) and 95856(h)(2)(D).

95891(d)(2)(C)- True-up Credit. The same issue and recommendation as the True-up Debit. Regulation should clearly define budget year "t". Since this only applies to the first compliance period we suggest specifying the actual years such as 2015 and 2016. (CCEEB 4)

Response: This comment was originally submitted for the discussion draft of the proposed regulation order, which was released for public consideration on January 31, 2014 and accompanied by an informal 15-day comment period. As this comment pertains to the informal discussion draft, no response is required. However, the commenter also submitted this comment letter at the April 25, 2014 Board hearing and therefore staff has included a response in this FSOR. Staff modified section 95891(d)(2)(B) as part of the 15-day regulatory amendments to clarify that vintage 2016 allowances will be used for this true-up. This must occur because the true-up equation is based on both 2013 and 2014 emissions data, the latter of which will not be available until 2015.

General Opposition

B-6.12. Multiple Comments: As the calendar clicks toward the April Board meeting, the Coalition respectfully requests that a vote on the Proposed Amendments, as well as, the remainder of the regulatory package, be removed from the Board's agenda. This delay will allow the ARB Board the opportunity to weigh in on this policy reversal, and allow for an additional 15-day package if the Board so desires.

To summarize, the Coalition opposes the final regulatory package being approved by the Board due to process, policy and data concerns surrounding the late shift in policy direction which significantly impacts our membership. We urge the Board to reject the Proposed Amendments and reinstate the recognition of an Atypical refining category for the purposes of refinery benchmarking. (CFEA 6)

Comment: In conclusion, Kern urges the Board to delay a vote on the Proposed Amendments to ensure sufficient time to analyze this significant change in policy direction [to a single CWB benchmark instead of separate typical and atypical benchmarks] and to allow for appropriate consideration of input from stakeholders and the Board. (KERN 6)

Comment: The USW therefore strongly urges CARB to hold an informational update during April in order for stakeholders and the public to receive additional CARB board member clarification and guidance. There should not be a vote taken in April while this process is still unsettled and incomplete. CARB staff can revisit this issue in a subsequent 15-day package, which will allow for all data and input to be fully included and properly vetted. (USW 5)

Comment: From October to March, the entire discussion between Alon and CARB was to ensure accurate data to set two separate benchmarks.
With a final vote scheduled for April, Alon requests that the item not be open for a final vote of the Board. (PARAMOUNT 4)

Comment: LTR respectfully requests that a vote on the proposed amendments related to refinery benchmarking, be removed from the Board's April 2014 agenda. (LTC 3)

> **Response:** ARB staff notes that the Board declined to postpone voting on the proposed rulemaking.
>
> ARB staff does not believe this rulemaking process has been incomplete. ARB staff has held several public workshops regarding refinery allowance allocation and other aspects of the Cap-and-Trade Regulation, including informational updates and opportunities for public comment. Staff has also communicated directly with numerous stakeholders, including representatives of each of the commenters.

USW Comments – Mixed Topics

B-6.13. Comment: The United Steelworkers (USW) fully support fair and equitable “like to like” facility refinery benchmarking, protecting and promoting local jobs and job growth, protecting tax bases, supporting local economies and communities, as well as implementing continuous process improvements within the refining sector. Our main focus and primary concern is for our many members whose jobs hang in the balance while the current undelineated and unfounded changes are in process. The final 15-day package is of grave concern to us. As currently drafted we continue to be subject to significant job leakage (losses), which will devastate our workers, their families and the communities they live in.

We are in agreement with the establishment of refinery benchmarking, however, refineries in and of themselves are not product based benchmarks. The benchmark must reflect what is manufactured by the refinery. The allowances also must be a benefit that is equal to all parties, with allowances fairly distributed in a manner that allows a refinery to either invest in low carbon technologies or pay instead. A program where certain refineries have to buy 40% of their allowances, with such a large gap between investment and the reality therein, is fundamentally flawed and is clearly a short term tax leading to facility shut downs. There is nothing in the legislative language of AB32 that allows for CARB to choose for some facilities to pay nothing while others are burdened to shoulder the bulk within the refinery sector until they close. This type of program cannot be replicated in other states and defies the entire intent of promoting and growing a sustainable green economy and future clean, green fuel projects. As strong supporters of AB32 and its tenets, this current path will force us to abandon some of the projects we hoped to implement as part of our overall greening of the industry plan.

The USW is still seeking the solid policy justification for the recent modifications that, to the best of our knowledge, utilizes unverified, inconsistent data. We continue to question CARB’s divergence from “one product- one benchmark”, followed by the elimination of intermediates and other products as being a bona fide product in their own right. Any stream bought, sold or traded is clearly a product, which means that refineries are being treated differently from other sectors to their detriment or windfall by design. We will strongly oppose this approach here as well as in other states where it may be introduced.

We again ask and reiterate the question we have raised since our initial call, which is: are any in-state refineries or individual facilities unfairly disadvantaged over any other facilities? As we see it, in-state refineries are still being penalized while out of state/country importing refineries benefit. The USW represents 95% of all oil refinery workers and our workers will be disproportionally affected by this arbitrary and inconsistent benchmarking approach where the one product excludes the many commodities. We do not want our members and their families to suffer because staff does not fully understand the refining sector and its inherent competitive nature. We need to offer our members assurances that their voices are being heard and that their jobs will be safe – good paying, highly skilled California jobs that have been protected for over 50+ years.

The USW has consistently defended AB32 programs actively and ardently, and it would be a sad testament to find that the reward for our dedication and efforts are unnecessary job losses related to an action based upon insufficient data and hasty throughput. The USW does not see the regulatory rush to complete this element in the regulation which continues to be murky. We strongly recommend that the refinery benchmarking be held for additional public comment and the rest of the regulation be completed. Our concerns are valid because the very same data that led to an atypical and typical definition in the formal board hearing led to its removal in the final 15-day package. Too much is at stake for our communities, families and workers for CARB to rush into this analysis and regulation, much of which has yet to be adequately substantiated.

The USW also formally requests a numerical graph by refinery data point on the individual allowance obligation for each refinery blinded in the same way that the current data is presented around the benchmark. There clearly was a reason the experts at the CARB workshops expressed the need for an atypical benchmark, and the CARB justification to date is still inconsistent with experts and with other existing refinery benchmarking programs.

The USW therefore strongly urges CARB to hold an informational update during April in order for stakeholders and the public to receive additional CARB board member clarification and guidance. There should not be a vote taken in April while this process is still unsettled and incomplete. CARB staff can revisit this issue in a subsequent 15-day package, which will allow for all data and input to be fully included and properly vetted. On behalf of our members whose livelihoods are at stake, we must ask for this consideration. (USW 5)

Response: In addition to the general response below, please see the response to 15-day comment B-6.12 in this chapter for the response to the specific request to delay the vote on the refinery benchmark portion of the 15-day amendment package.

Compliance Costs and Job Protection
ARB staff appreciates the commenter's consistent support and defense of AB 32. Through the Cap-and-Trade Program authorized by AB 32, ARB staff seeks to reduce greenhouse gas emissions in a manner that preserves California's economic prosperity. Staff understands the importance of job security for workers in industries covered by the Cap-and-Trade Program, and staff also believes that compliance costs for refineries are not so burdensome as to lead to facility closure or job losses. Under the proposed benchmarks, staff estimates the average cost to comply with the Cap-and-Trade regulation without improving refinery emissions efficiency to be less than 0.2 cents per gallon of product. The maximum compliance cost for a single refinery is less than 0.6 cents per gallon of

product. In the context of total production costs, fuel taxes, and regular price fluctuations, this appears to be a manageable cost.

CWB-based Benchmark
ARB staff has worked constructively with refinery stakeholders to develop a benchmark based on the CWB. Refineries differ by the types of refining processes used and by the products that they produce. Different refinery products require different levels of crude refining intensity. For example, gasoline is a relatively light product that requires intensive crude refining to produce, while asphalt is a relatively heavy product that requires less refining, and therefore produces less GHG emissions per unit of product. A simple barrel-based benchmark does not capture this emissions intensity variation for different products, which limits its usefulness. CWB is a proxy for refinery production that acknowledges the variation in refining intensity for producing different products. CWB captures variation in refinery complexity and also correlates well with facility GHG emissions. For these reasons, staff believes that the CWB-based benchmark is more equitable than a simple barrel-based benchmark. Staff believes that a single CWB-based benchmark treats the covered entities equally and enables fair and equitable allocation.

Single Refinery Benchmark
Under the Cap-and-Trade Program's "one product, one benchmark" principle, benchmarks are not differentiated by technology, fuel mix, size, age, climatic circumstances, or raw material quality.

The changes to refinery-related benchmarks were based on a dispassionate analysis of data provided by the refineries to ARB staff during the months preceding the release of the amendment package. The CWB calculation methodology was developed by Solomon Associates based on data from large- and medium-sized refineries. Small refineries that were not included in the development of the CWB calculation methodology expressed concern that they would not be treated fairly under a CWB-based benchmark. A special "atypical" refinery benchmark was considered during the process to accommodate this concern, but the collected CWB data for California refineries did not support the assertion that small refineries are less efficient than large ones under the CWB metric. Consequently, the special "atypical" refinery benchmark was dropped from consideration and a single benchmark was proposed. The single benchmark adheres to the general "one product, one benchmark" principle that ARB staff uses for all covered sectors by not differentiating by refinery size or raw material quality.

Fairness and Data Consistency
ARB staff believes that using product-based benchmarks to provide free allowances is equitable and provides properly aligned incentives for emissions reductions. When applying product-based benchmarks, it is natural that more emissions efficient facilities will have more of their compliance obligation covered

by freely allocated allowances compared to less efficient facilities. The gap between a refinery's compliance obligation and the number of free allowances that it receives is dictated by its emissions efficiency relative to the rest of the sector.

Staff believes that the CWB production data and emissions data upon which the refinery benchmark is based are sufficient and consistent. In addition, the process of developing the new benchmarks has been inclusive, interactive, and rigorous. Staff regularly met with stakeholders throughout the rulemaking process to gather data, listen to concerns, and explore solutions to the issues that were confronted.

In the comment, the question is posed: "*Are any in-state refineries or individual facilities unfairly disadvantaged over any other facilities?*" ARB staff acknowledges that compliance costs vary among refineries. Carbon costs per gallon of product are lower for more efficient refineries and higher for less efficient refineries, but each facility is treated consistently and fairly, in both benchmark development and application. CWB is calculated following a procedure that is widely accepted in the refining industry, and the calculation method is the same for all facilities. ARB staff believes that in-State refineries are treated fairly under the proposed refinery benchmark.

Refinery Allowance Obligations
The commenter requests a graph of the individual allowance obligation for each refinery. A refinery's compliance obligation is simply equal to its carbon dioxide equivalent emissions for the given year. This request is outside of the scope of the 15-Day Modifications.

Hydrogen Allocation

Calculation Basis of the Hydrogen Benchmark

B-6.14. Multiple Comments: Air Liquide also supports the methodology that CARB used to develop its revised benchmark for gaseous hydrogen production.

… Air Liquide supports CARB's decision to propose a single benchmark for hydrogen production facilities, using data from both merchant and refinery-owned hydrogen production facilities in California. (LIQUIDE)

Comment: Proposed refinery and hydrogen benchmarks are highly consistent with ARB cap & trade principles – Air Products strongly endorses the underlying principles of "One Product – One Benchmark," consistent benchmark stringency, and deriving benchmarks from data representative of the entire population of affected facilities. In this regard, Air Products supports ARB's commitment demonstrated in this latest proposal to base benchmarks on all producers' data, to propose discrete gaseous and liquid hydrogen product benchmarks, and to apply stringency to the benchmarks that is consistent with other industrial assistance product benchmarks.

The proposal maintains the principle of defining a single benchmark value for each distinct product – regardless of the many variations in practice (process, feedstock, facility ownership, etc.). We acknowledge the ARB's efforts to expand the emission and production data set for deriving the gaseous hydrogen benchmark to include both refinery-produced hydrogen and industrial gas company, or "merchant"-produced hydrogen. The resulting benchmark value of 8.94 allowances/metric tonne of gaseous hydrogen produced is significantly more representative of the entire gaseous hydrogen production facility "fleet" than the "merchant-only"-based benchmark proposed in October 2013…

These proposed benchmarks also restore a consistent stringency across all sectors/products eligible for industrial assistance. The proposed benchmark values are based upon "90% of sector average or best in class, whichever is greater," for all hydrogen production. This was not the case under the interim benchmark originally applied for the first two years of the program, but is rectified under the new benchmark proposal. This principle of consistent stringency, when combined with the "One Product – One Benchmark" principle discussed above, ensures equitable treatment of all covered sectors in the state. (APC 3)

> **Response:** Thank you for the support.
>
> ARB staff has decided to use both refinery and merchant hydrogen data to calculate a single benchmark for hydrogen.
>
> For reasons mentioned by several commenters, ARB staff finds it important to give the same benchmark to refinery hydrogen and merchant hydrogen. Refinery hydrogen plants and merchant hydrogen plants serving refineries are providing the same product to the same industry, and thus fall under the "one product, one benchmark" principle. Because they provide the same product, it would be inequitable to assign different benchmarks based on process design or ownership.
>
> ARB staff considered three main options for calculating the hydrogen benchmark: using CWB, using only merchant hydrogen data, or using both refinery hydrogen and merchant hydrogen MRR data.
>
> Staff calculated a potential CWB-based hydrogen benchmark using all refineries and merchant hydrogen facilities. However, the design of CWB probably overestimates the emissions due to hydrogen production relative to most other refinery processes. This is because when Solomon Associates created the CWB factors, they assumed that natural gas is the fuel source for all refinery activities, which results in overestimation of process emissions relative to fuel-based emissions. This can occur because CWB estimates process emissions relative

to fuel-based emissions, making all process emissions appear unrealistically high. This problem with CWB is in contrast to CWT, which does not have the same problem because Solomon Associates created it using the EU average refinery fuel mix as the assumed fuel source. ARB staff does not have the data to recreate CWB using the California average refinery fuel mix. Also, because the data used to create CWB factors are only from Solomon Associates clients, they are likely to exclude most merchant hydrogen data and may not be representative of hydrogen production in California.

In the 45-day regulatory text, ARB staff proposed a hydrogen production benchmark using merchant hydrogen data and the standard approach of 90% or best in class, whichever is less stringent. Merchant hydrogen plants are the source of about one quarter of the gaseous hydrogen produced in California, and both merchant hydrogen and refinery hydrogen facilities generally use steam methane reforming as their means of on-purpose hydrogen production. A benchmark based on merchant hydrogen therefore may be reasonably representative of California hydrogen production. However, ARB staff prefers to use data from all facilities when available.

Therefore, ARB staff has adopted a hydrogen benchmark calculated using both refinery and merchant hydrogen production and emissions data. Merchant hydrogen data, as above, are data collected under MRR. Refinery hydrogen data are from the voluntary refinery survey in which all California refineries participated. These data were combined to calculate a benchmark which is 90% of average emissions intensity across all hydrogen produced by hydrogen production units in California. Refineries' increased provision of the necessary data made this approach feasible when it was not feasible before. This approach still fails to account for electricity export and net steam consumption of refinery-based hydrogen production. Nevertheless, ARB staff deemed it the best of available hydrogen benchmarking approaches.

Opposition to Definition of On-Purpose Hydrogen

B-6.15. Multiple Comments: However, we note that CARB issued guidance on March 28 under the Mandatory Reporting Regulation requiring that, in determining the amount of "on-purpose hydrogen" on which allowance allocations are based, reporting entities should subtract the amount of molecular hydrogen contained in the feedstock. CARB has also revised its reporting tool to exclude molecular hydrogen from the amount of "on-purpose hydrogen" reported. This is the first time that CARB has suggested that molecular hydrogen should be excluded from the amount of on-purpose hydrogen reported. We strongly oppose this guidance, as it is inconsistent with the method by which CARB has developed the benchmark.

First, we note that the requirement to subtract molecular hydrogen from the mass of "on- purpose hydrogen" produced is found nowhere in AB 32, the Cap-and-Trade

Regulation, or the MRR. There is no legislative or administrative requirement to ignore emissions associated with processing molecular hydrogen.

Second, CARB developed its proposed benchmark of 8.94 allowances/MT H2 using production data that included molecular hydrogen contained in the feedstock. CARB could not have subtracted molecular hydrogen in developing its benchmark because the amount of molecular hydrogen in feedstocks was not reported to CARB, and indeed there was no field in the reporting tool to report this information, until this year. The methodology that CARB used to calculate its benchmark was the correct one, and it is the reporting guidance and not the benchmark that should be changed. CARB's benchmark development process correctly recognized that there are greenhouse gas emissions associated with the processing of molecular hydrogen in the feedstock, and that an accurate benchmark should reflect these emissions. CARB should allocate allowances using the same methodology that it used to develop the benchmark. Accordingly, allowance allocations should be based on the total mass of hydrogen produced, including molecular hydrogen contained in the feedstock.

Finally, if CARB were to incorporate a requirement to subtract molecular hydrogen from the amount of "on-purpose hydrogen" produced, that requirement would not advance CARB's goal of reducing greenhouse gas emissions. Such a requirement would create disincentives for the use of refinery fuel gas as a feedstock and result in flaring or waste of refinery fuel gas while at the same time increasing the consumption of natural gas, with associated increases in greenhouse gas emissions from the extraction, processing and distribution of that gas. Air Liquide has consistently urged CARB to avoid creating distortions in the hydrogen production market that are unrelated to CARB's goal of reducing greenhouse gas emissions. CARB's last- minute change to the reporting guidance will create market distortions.

CARB should therefore withdraw its guidance under the MRR excluding from "on-purpose hydrogen" the mass of molecular hydrogen contained in the feedstock, and confirm that allowances will be allocated based on total hydrogen production, without subtracting molecular hydrogen contained in the feedstock. (15.98 AIR LIQUIDE)

Comment: ARB has applied a new definition for gaseous hydrogen production that is inconsistent with the basis used for deriving the gaseous hydrogen product benchmark – The 15- day package includes a new term in the definitions for "on-purpose hydrogen gas", which under the proposed new benchmark becomes the basis for the allowance allocation.

While this term was first issued in the revision to the Mandatory Reporting Rule in October 2013, it was only on March 28, 2014, that the ARB issued "Hydrogen Producers Reporting and Verification Guidance" which, for the first time, articulates how the term "on-purpose hydrogen gas" is to be interpreted; specifically, that any molecular hydrogen that in present in feedstock streams is to be excluded from the representation of the hydrogen plant's production. We strongly oppose this guidance, as it is inconsistent with the method by which the ARB has developed the benchmark.

The ARB developed its proposed benchmark of 8.94 allowances/metric tonne of hydrogen using production data from some facilities that included molecular hydrogen contained in their feedstock. ARB could not have subtracted molecular hydrogen in developing its benchmark because such data was not reported to the ARB in the 2008-2010 timeframe.

Air Products agrees that the methodology that the ARB used to calculate its benchmark was correct; it is the reporting guidance and not the benchmark that should be changed. The ARB's benchmark development process correctly recognized that there are greenhouse gas emissions associated with the processing of molecular hydrogen in the feedstock (both in contributing to the sensible heat addition needed and the purification process for recovery of this hydrogen) and that an accurate benchmark should reflect these emissions. It is essential that the ARB allocate allowances using the same methodology that it used to develop the benchmark. Accordingly, allowance allocations should be based on the total mass of hydrogen produced, including molecular hydrogen contained in the feedstock.

If the ARB feels compelled to incorporate a requirement to subtract molecular hydrogen from the amount of "on-purpose hydrogen" produced, then the benchmark should be re-derived to account for the reduced production that would be reflected in the revised intensity denominator of the benchmark calculation. (APC 3)

Comment: In the fall of 2013, CARB proposed that a single efficiency benchmark be established for both merchant hydrogen plants and refinery plants. This required significant communication and data exchange between refineries and CARB staff over the last few months to "extract" refinery hydrogen plant emissions and hydrogen production data from refinery data. We are concerned with the appropriateness of the data that was provided by all companies involved in crafting the benchmark. We respectfully request that CARB continue to work with companies in the coming months regarding data reporting and benchmark development. Please provide a 15 day package that revisits the benchmark for hydrogen plants.

Additionally, we support the comments of the Western States Petroleum Association (WSPA). (PHILLIPS 6)

Comment: The new hydrogen plant benchmark proposed by ARB may be materially inaccurate due to inconsistent communication of hydrogen reporting requirements. Specifically, the reporting requirements that have been in-place, and were used for benchmarking, are not consistent with the new reporting Guidance provided to verifiers and reporters on March 21. This inconsistency puts companies in potential compliance jeopardy through, for example, vulnerability to allegations of material misstatements. This issue just emerged within the past two weeks, yet it could impact reporting of 2013 data, which is due to ARB next week (April 10). WSPA believes this issue must be addressed with respect to the implications on the development of the hydrogen benchmark, as well as near term and future reporting required by ARB.

Recommendation: Given the uncertainty in MRR as to what is reported and what should be reported, at a minimum, the recent guidance proposed by ARB should be rescinded and amended, depending on the outcome of further dialogue with stakeholders. It is likely that ARB will need to revisit the hydrogen benchmark as well. We look forward to working with staff to ensure that future reporting Guidance is consistent with the MRR Regulation and can be achieved in practice by regulated entities. (WSPA 5)

Comment: A more recent issue relates to an inconsistency between the hydrogen plant benchmark and what is required by recent reporting guidance. We have been meeting with staff on this and look forward to additional discussions. (TESORO 5)

Comment: Similarly, we have concerns about the hydrogen plant benchmark proposed by ARB. We think it may be materially inaccurate due to inconsistent communication of hydrogen reporting requirements. This could be so because the reporting requirements that have been in place and that were used for benchmarking were not consistent with the new reporting guidance provided earlier this year.

WSPA believes this issue must be addressed with respect to implications in the development of the hydrogen plant benchmark, as well as near term and future term reporting to ARB…

The reporting and benchmarking must be on a consistent basis. We encourage a process to true-up and resolve inconsistencies in both the refinery and hydrogen plant benchmark. (WSPA 6)

> **Response:** Comments about MRR reporting guidance are outside the scope of proposed changes to the Regulation so no response is required. However, ARB staff worked closely with stakeholders on this issue and determined that it was appropriate to amend the MRR hydrogen guidance document to not require reporters to subtract feedstock H_2 from their reported hydrogen gas production. Therefore, staff asserts that the benchmark and reporting of hydrogen gas production through MRR are appropriately aligned, and it is not necessary to recalculate the hydrogen gas benchmark.

Support for Liquid Hydrogen Benchmark

B-6.16. Multiple Comments: Further, ARB has correctly recognized the inherent differences in gaseous and liquid hydrogen products and derived discrete product benchmarks for each of them. While these products are the same at the molecular level, the nature of the production processes, physical form, purity and commercial markets served create very distinct CO2 emission footprints in their production. The proposed value of 11.9 allowances/metric tonne of liquid hydrogen sold is appropriate and necessary to treat liquid hydrogen product with a consist stringency. (APC 3)

Comment: Praxair supports the Air Resources Board's ("ARB") proposed update to the emissions benchmark specified in Table 9-1 for liquefied hydrogen. As amended the Cap-and-Trade Regulation would recognize that liquefied hydrogen is a separate and distinct product from gaseous hydrogen. The Cap-and-Trade Regulation would allocate 8.94 allowances for gaseous hydrogen and 11.9 allowances to liquefied hydrogen. The allocation for liquefied hydrogen would be based on the quantity of liquid hydrogen sold.

Praxair supports the ARB's efforts to recognize the diverse economic activities occurring in California. The separation of liquid and gaseous hydrogen achieves parity with other aspects of the regulation where the ARB has acknowledged the distinctions in different product types that may be categorized under a common four, five or six digit NAICS code (e.g., various types of food processing and atypical vs. typical refineries).

As Praxair has noted in its previous comments on the Cap-and-Trade amendments - liquefied and gaseous hydrogen have different demands and uses for their products, and similar to the refining sector, liquefied and gaseous hydrogen production are structurally distinct. Liquefied hydrogen plants are smaller than plants producing gaseous hydrogen for use by refineries. This is because liquefied hydrogen plants are sized to meet the regional and fluctuating market demands for liquefied hydrogen. As such, liquefied hydrogen plants are typically 5 - 10% of the size of gaseous hydrogen plants serving refineries. Moreover, due to the predictable demand of refineries, gaseous hydrogen plants typically operate closer to their nameplate capacities, resulting in higher operating efficiencies. Liquefied hydrogen plants have less consistent demand, meaning they cannot consistently achieve the same operating efficiencies as gaseous hydrogen plants serving refineries. Thus, due to the completely different customers and demands for their products, liquefied and gaseous hydrogen plants have different GHG emissions intensities.

Moreover, gaseous hydrogen is typically consumed close to the gaseous hydrogen production facility (such as in a refinery setting) and there are minimal commodity losses between what is produced and what is delivered to customers. On the other hand, there are commodity losses associated with the handling and delivery of liquefied hydrogen. Liquefied hydrogen is transported by truck and there can be losses due to the distance traveled, elevation, temperature and other factors. Since liquefied hydrogen producers must report the volumes sold to their customers under the Mandatory Reporting Regulation (and this information will be the basis for the allowance allocation), the liquefied hydrogen benchmark would appropriately account for the delivered product. It is also important to note that sales data is more easily verified than production data, resulting in a more accurate allocation to liquefied hydrogen producers.

Finally, liquefied hydrogen plants are structurally different due to the purity requirements for creating liquefied hydrogen. To produce liquefied hydrogen, the hydrogen feedstock from a Steam Methane Reformer ("SMR") must be purified to 10 ppm. By comparison, SMR's that serve refineries only require a purity of 1,000 ppm. To achieve the higher purity for liquefaction, the filtering process disposes of both hydrogen and impurities together. The impact of purifying the hydrogen is the loss of approximately 5.6% of the molecules created in the reforming process. This reduced volume of hydrogen increases the CO2 emissions per unit of liquid hydrogen produced.

CONCLUSION

Praxair supports the ARB's recognition of the distinctions between gaseous and liquefied hydrogen and the development of an appropriate benchmark for liquefied hydrogen that is consistent with the ARB's analysis for other products. We appreciate the ARB staffs attentiveness to these issues and thank the ARB staff for their diligent efforts to address the myriad issues facing California diverse economy in an open and transparent manner. (PRAXAIR 3)

> **Response:** Thank you for the support.
>
> Some of ARB staff's reasons for setting a liquid hydrogen benchmark differ from the reasons offered by commenters. Further detail is given in the response to 45-day comment B-8.31 in Chapter IV.

Support for Hydrogen True-Ups

B-6.17. Comment: The corrected hydrogen benchmarks will be retroactively applied to Compliance Years 2013 and 2014 through the "allocation true-up" process – Air Products supports the application of the allowance allocation true-up process to allow for both changes in the applicable product benchmarks, as well as correct for differences between actual and anticipated production activity. The true-up formula will apply the new benchmark value to the 2013 compliance year when the 2015 allocations are made in October 2014, correcting for the lower benchmark used when the initial 2013 allocations were made in 2012. Likewise, the 2014 allocations made in October 2013 will be corrected through the true-up when 2016 allocations are made in October 2015. In this way, hydrogen producers are treated properly and consistently with all other product-based industrial assistance recipients. (APC 3)

> **Response:** Thank you for the support.

Coke Calcining

B-6.18. Comment: Phillips 66 has provided supporting information on this issue to ARB in written comments on August 2, 2013, August 26, 2013, October 25, 2013 and March 12, 2014, which written comments are incorporated here by reference and in multiple meetings with CARB staff. The justification for use of the slower declining cap factor for coke calcining is supported by existing CARB documentation which includes:

• Process emissions greater than 50%: The annual emission reports (MRR) to ARB for our calciner operation (Phillips 66, San Francisco Carbon Plant, ARB Reporting ID 100351) demonstrate that process emissions are consistently greater than 50%, and in fact are >90%.

• High Leakage Risk: Cap-and-Trade regulation Table 8-1 assigns a "High Leakage Risk" designation to coke calcining (NAICS 324199), satisfying the second criteria.

• High Emissions Intensity: Coke calcining has high emissions intensity. ARB's Appendix K, Table K-10 lists NAICS Code 324199 as having an Emissions Intensity (EI) value of 9,754. The threshold for designation as a high emissions intensity sector is 5,000 EI. Coke calcining therefore meets all three of CARB's criteria.

CARB has determined the criteria to be granted the slower cap decline factor: (1) process emissions greater than 50%; (2) high leakage risk; and, (3) high emissions intensity. These conditions have all been satisfied and CARB staff has failed to provide verbal or written justification of the decision to retain the incorrect cap adjustment factor. CARB is moving forward in silence.

Initial discussions on whether the more general NAICS Code 324 or the more specific Code 324199 should be assigned to coke Calcining were productive. CARB has correctly assigned Code 324199 as is recommended by the U.S. Department of Commerce. In fact, the Department explicitly warns businesses to not use the more general code (e.g. NAICS Code 324) that contains more subcategories.

We note that, CARB in Table K-10, did identify both cement and lime manufacturing as high emissions intensity (with EI exceeding 5000) and does list them in Table 9-2, yet coke calcining is specifically excluded from the correct designation.

Coke calcining clearly meets all criteria for designation as a sector in Table 9-2 where the slower cap decline factor is applicable. We respectfully request that CARB place coke calcining in Table 9-2 where it belongs and the correct slower cap decline factor be applied. Please provide these changes in an additional 15-Day Package modification that reflects the proper designation. (PHILLIPS 6)

> **Response:** This comment is outside of the scope of the proposed 15-DAY Modifications so no response is required.

C. LEAKAGE

C-1. Changes to the Industrial Assistance Factor

C-1.1. Multiple Comments: Chevron is pleased that ARB is considering adoption of the following policies which represent improvements in the cap and trade program:

- Industry Assistance – Chevron supports the proposed change in the application of the industry assistance factor that recognizes the competitive environment in the refining sector and other energy intensive trade exposed industries which if left unchanged, could lead to leakage and loss of California jobs. (CHEVRON 6)

Comment: WSPA supports the ARB proposal to increase the Industry Assistance Factor (IAF) to 100% (up from 75%) during the second compliance period for petroleum refineries and other industry groups classified by the ARB as "Moderately exposed". The proposed change in the 2nd compliance period recognizes the risk of emissions leakage and the potential harm to domestic (i.e., within California) facilities. WSPA remains concerned about the risk of leakage during the 3rd compliance period, when the IAF is proposed to be reduced to 75%. We look forward to working with ARB to investigate the adverse impacts of the proposed IAF reduction and the potential for increasing the IAF in the 3rd compliance period so that leakage risks are minimized. (WSPA 5)

Comment: For example, we support the increased industry assistance factor provided to reduce trade exposure. Tesoro believes it is important in regulations like cap and trade that the staff and Board work on provisions that do not disadvantage in-state manufacturers in favor of out-of-state manufacturing. Simply put, we must have a level playing field. (TESORO 5)

Comment: We strongly support the industry assistance factor. We supported the ARB proposal to increase the industry assistance factor to 100 percent during the second compliance period for moderately trade-exposed sources. The proposed change in the second compliance period recognizes the risk of emission leakage as the potential harm to domestic within California facilities. As a staff indicated, we look forward to working with the ARB to investigate the adverse impacts of the proposed reduction and the potential for increasing the industry assistance factor in the third compliance period so leakage risks are minimized. (WSPA 6)

Comment: Not surprisingly, we're also strongly in support of the increase in the industry assistance factor. We think it's important to take care of leakage. (CHEVRON 7)

> **Response:** Thank you for the support.

C-1.2. Comment: The Industry Assistance Factor for the Gypsum Product Manufacturing Industry in Table 8-1 should be 100% for the Third Compliance Period.

Although USG appreciates the modifications to the Industry Assistance Factor for the GPM industry in the second and third compliance periods, USG believes that the annual Industry Assistance Factor should be 100 percent for the entire period 2013 through 2020. It is our position that in assigning a “medium” leakage risk classification to the GPM industry, CARB has understated the risk leakage for the industry.

In assigning a leakage risk classification to an industry, CARB applies a methodology that assigns equal weight to the concepts of emissions intensity and trade exposure. While we are of the opinion that the GPM industry should not be evaluated as an “emissions intense” industry, we are concerned that CARB is understating the local trade exposure risk to the industry. USG is particularly concerned that using national and regional data (mostly from ports) for the calculation of Trade Share in Appendix K of the rule underestimates the potential trade exposure of gypsum products to the state of California from other States.

Gypsum board is a consistent quality, commodity material that can be cost-effectively transported by rail. As a consequence, gypsum board can be produced in a specific state or country and easily transported and sold in a different state or country. Our concern is that CARB has not taken this attribute fully into account when assigning the risk leakage classification to the GPM industry.

USG has gathered industry data in California for the years 2001-2012. *On average, our best estimate is that 21% of wallboard sold in California is produced outside of the state.* The data is confidential in nature and can be shared with CARB provided that it is protected accordingly. In reviewing the Proposed Trade Exposure Classification in Table K-6, a trade share in excess of 19% would be considered “High”. As a result, the GPM industry should be assigned a “High” leakage risk according to CARB’s original Leakage Analysis. We understand that CARB is currently reviewing the Industry Assistance Factors and would appreciate the opportunity to share data that we have collected with you. (USG)

> **Response:** This comment is outside the scope of the proposed 15-Day Modifications to the Regulation, so no response is required. However, pursuant to the direction in Resolution 12-51, staff is awaiting the results of new research that will improve upon the leakage risk assessment of industries covered by the Regulation. This new research will provide additional insights into the potential leakage risk posed by the long-term implementation of the program on industrial sectors, and will inform ARB staff’s evaluation of leakage risk factors for the third compliance period. Any changes to leakage risk classifications or assistance factors for the third compliance period would be proposed in subsequent rulemakings.

C-1.3. Comment: And with that, I would like to call the Board's attention to one particular area of the rule that, while we think many businesses are in need of some transition assistance, there is the largest sector of polluters in California, the refining sector, which really are unsure and actually don't think need such transition assistance.

We understand that the regulation today, of course, does have that in there. But we would ask for commitment on the part of the Board as we do engage in this analysis of the appropriateness of transition assistance that really specific emphasis be placed on whether it continues to be appropriate for that particular sector, which year over year, of course, records record profits. And as gas prices are going up, we really take care of understanding what are the economic drivers of those decisions. (EDF 3)

> **Response:** This comment is outside the scope of the proposed 15-Day Modifications to the Regulation, so no response is required. Please see the response to a 45-day comment C-1.4 in Chapter IV for additional information.

D. COVERED SECTORS AND EXEMPT EMISSIONS

D-1. Exempt Emissions

Combined Heat and Power and District Heating

D-1.1. Comment: The amendments should further clarify that generators that have executed contracts with investor owned utilities (IOUs) to provide compensation for GHG compliance costs should not receive a "but for" exemption. PG&E suggests the following revisions to Section 95851:

> (c) Operators of cogeneration facilities and district heating facilities that have been approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j), that meet or exceed the annual threshold in section 95812~~(d)~~(c) and have not executed a power purchase agreement pursuant to the Combined Heat and Power Program Settlement Agreement approved by CPUC Decision 10-12-035 with a privately owned utility as defined in the Public Utilities Code section 216 will have ~~a~~no compliance obligation and are not covered entities ~~beginning with the second~~during the first, second, and third compliance periods. ... (PGE 4)
>
> **Response:** Because "but-for" entities are not covered entities, they will face an indirect GHG cost passed through in the price they pay for natural gas. There is no reason to require that facilities demonstrate that they are not being compensated for carbon costs in order to qualify for the "but-for" exemption, because *all* but-for entities should be facing indirect GHG costs through natural gas purchases.

D.1.2. Comment: Central Contra Costa Sanitary District (CCCSD) appreciates the opportunity to comment on the proposed amendments to the California Air Resources Board (ARB) Cap and Trade regulations with respect to the limited exemption of emissions associated with qualified facilities operating a cogeneration unit. CCCSD supports the proposed amendments and believes that it will result in a net reduction in greenhouse gas (GHG) emissions. In addition, CCCSD appreciates that ARB has extended the limited exemption for qualified cogeneration facilities to include the first, second, and third compliance periods.

CCCSD operates a permitted wastewater treatment facility in Martinez, California, and provides treatment of approximately 45 million gallons per day of wastewater to 462,000 residents and businesses in the Central Contra Costa County. Our business mission is to protect the public health and provide wastewater treatment at responsible rates. CCCSD operates a Cogeneration unit that combusts natural gas to generate steam and electricity for the treatment plant. The thermal output generated by Cogeneration is used to drive the steam turbine that provides power to the aeration blowers for the secondary treatment process. The combustion of natural gas in Cogeneration reduces overall GHG emissions and offers a cost-effective, twofold benefit of electric and thermal energy recovery.

Based on the proposed amendments in Section 95851, only facilities with cogeneration units can qualify for the limited exemption of emissions if they meet or exceed the Cap and Trade annual inclusion threshold of 25,000 MT C02e. CCCSD is not currently subject to Cap and Trade. CCCSD imports electricity from the grid to remain under the Cap and Trade annual inclusion threshold. The proposed amendments in Section 95851 does not incentivize cogeneration facilities, such as CCCSD, that are below the Cap and Trade inclusion threshold to operate cogeneration at maximum output as a means to provide a reliable and cost-effective source of thermal and electrical energy while reducing overall GHG emissions. CCCSD strongly suggests including facilities with cogeneration units that are under the annual inclusion threshold for Cap and Trade in the limited exemption of emissions. This will further incentivize facilities with cogeneration units to reduce their dependency on the grid and to maximize their cogeneration output of electricity and recoverable thermal energy.

In accordance with the proposed Section 958520), [sic] a facility with a cogeneration unit would only qualify for the limited exemption of emissions from the production of qualified thermal output if the facility's annual covered emission and remaining covered emissions both meet the two conditions listed in 95852(j)(1) and 95852(j)(2) for each year from 2008-2013. CCCSD strongly recommends the qualification period for the limited exemption be extended to include years 2014-2020. (CCCSD 2)

> **Response:** It is not clear that the commenter can reduce overall GHG emissions by running its facility at maximum output in order to avoid purchasing power from the grid. This is particularly true for facilities, such as the commenter’s facility, that receive grid power from an EDU that has very low emission power due to having significant amounts of hydropower, renewables, and nuclear power in their resource mix. The commenter has the option of staying below the threshold, and may have an option of using biogas in its cogeneration unit. The commenter suggests that facilities with cogeneration units that have annual emissions below the inclusion threshold for a compliance obligation under the regulation should be included as eligible for the limited exemption of emissions. In fact, any facility, including a cogeneration facility, is exempt from a compliance obligation if its annual emissions are below the threshold, unless the facility is an opt-in entity under the regulation.

Waste-Energy Emissions

D-1.1. Comment: Covanta supports the limited exemption for EfW facilities for the first compliance period and in data year 2015. The CARB Board Resolutions 11-32 and 12-33 in October of 2012 stated that the ARB will continue to work with CalRecycle and other agencies and stakeholders to “determine the most appropriate treatment of municipal solid waste under the cap-and-trade program including emission characterization methodologies.” This limited exemption will allow for the completion of this process.

However, as currently proposed, the regulation presumes that the appropriate mechanism moving forward will be to include EfW facilities in the cap as a covered entity as of January 1, 2016. The preponderance of data have demonstrated that EfW facilities offer GHG savings relative to landfills, an uncapped sector. In a 2012 study, CalRecycle concluded that the state's EfW facilities provide a net GHG reduction relative to landfills, joining the European Union, the U.S. EPA, the National Renewable Energy Laboratory (NREL), the World Economic Forum, the IPCC, and the Clean Development Mechanism of the Kyoto Protocol in recognition of EfW as a GHG mitigation measure relative to landfilling.

New data show that the methane emitted by landfills and other sources is even more damaging than previously thought. Since the October 2012 Board Resolution and the CalRecycle study, the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report has updated the 100 year global warming potential of methane to 34 times as potent as CO2 when climate- carbon feedbacks are included. Over a 20-year timeframe, identified in the February 10, 2014 proposed update to the Scoping Plan as a better reflection of what can be achieved in the near term by mitigation, methane is 86 times as potent as CO2. This new data, and the shorter term perspective on methane, further demonstrates the positive characterization of EfW versus landfill from a GHG perspective and provides a sound basis to exclude the three EfW facilities moving forward. (COVANTA 2)

> **Response:** Thank you for the support. ARB staff is currently using a global warming potential (GWP) of 21 for methane for all calculations. We continue to monitor the latest scientific information on the GWP for methane, and other greenhouse gases, and will make adjustments in the future to update ARB's AB 32 programs with the latest GWP factors. Staff encourages Covanta and the other stakeholders to continue to work closely with CalRecycle and ARB to develop the final recommendations on how to best incentivize greenhouse gas emissions reductions in the waste-to-energy sector.

D-2. New Sectors

Compliance Obligation for Natural Gas Suppliers

D-2.1. Comment: Issue previously raised by SDG&E and SoCalGas and not addressed in the 15-day changes.

<u>Section 95852.2(b)(4): Emissions without a compliance obligation</u>

Under the proposed amendments to Section 95852.2(b)(4), vented emissions from underground storage facilities will count towards the inclusion threshold. Vented and fugitive emissions can only be excluded for industry segments “onshore natural gas transmission compression” (95152(e)) and “natural gas distribution” (95152(i)). Vented and fugitive emissions for underground natural gas storage (95152(f)) are not included in this exemption because ARB assumes that the injection and withdrawal meters are located downstream of injection/withdrawal compressors. Downstream metering excludes gas vented at a compressor and therefore these emissions must be accounted for. Injection meters at SoCalGas are located upstream of the compressor and therefore inclusion of venting emissions will be double counting. Compressors are not used for withdrawing gas from storage, so withdrawal meter location is not an issue.

<u>Modification to Section 95890</u>
(4) Vented and fugitive emissions for the following industry segments by local distribution companies that report under section 95122 of MRR;
(A) 95152(e) and 95152 (i) of MRR
(B) 95152(f) of MRR if injection and withdrawal meters are located upstream of an injection or withdrawal compressor (SEMPRA 4)

> **Response:** ARB staff thanks the commenter and agrees that the vented emissions from underground storage would be double counted in the event that the injection meter is located downstream of the compressor because the emissions would also be captured under the natural gas supplier emissions calculated pursuant to section 95122 of MRR. However, to the best of ARB staff’s knowledge, and as supported by the commenter’s statements, metering is upstream of all injection compressors. Therefore, no double counting would result.

D-2.2. Multiple Comments: <u>Section 95852.2. Changes to Section 95852.2(b)(4) Should Not Become Effective Until January 1, 2015. ARB Should Clarify the Effective Date of Other Regulatory Changes</u>

The proposed amendments to Section 95852.2(b)(4) further limit which emission sources qualify for a compliance exemption under the Cap-and-Trade Program, causing vented emissions from underground storage facilities to count towards the inclusion threshold. This unexpected change may cause PG&E’s largest underground gas storage facility to carry a compliance obligation for 2014. ARB first provided notice of this significant change in the draft 15-day amendments posted on January 31, 2014, which conflicts with the Administrative Procedures Act: "No state agency may adopt, amend, or repeal a regulation which has been changed from that which was originally made available to the public pursuant to Section 11346.5, unless the change is (1) nonsubstantial or solely grammatical in nature, or (2) sufficiently related to the original text that the public was adequately placed on notice that the change could result from the originally proposed regulatory action."

Attachment A to the October Board Resolution suggested that staff would "propose to make a minor modification to clarify that only emissions that occur along the natural gas transmission and distribution networks are exempt when calculating a local distribution company's compliance obligation." PG&E sought clarification of this proposal and was informed by staff via email that the amendments would not affect the company's compliance obligation. This did not prove to be the case. ARB should clearly state that changes to the Cap-and-Trade Regulation's classification of covered emissions do not apply until January 1 of the year following the year in which the regulatory change is made; in this case, January 1, 2015. This will ensure that entities have adequate notice of changes and are able to procure sufficient compliance instruments and, for natural gas utilities regulated by the CPUC, establish the requisite cost-recovery mechanisms required under its regulatory structure to address a new or increased obligation.

In addition, due to the extensive number of changes and new reporting requirements that may be required of entities subject to the Cap-and-Trade Regulation, many of which pertain to auction participation, ARB should clarify the effective date of other provisions established under the new regulation and clearly communicate to stakeholders which auction will be subject to the new requirements. This clarification will provide covered entities and other market participants regulatory certainty and will facilitate compliance with the amended regulation. (PGE 4)

Comment: Recently released regulatory language suggests that ARB intends to transition emissions produced by these facilities out of the exempt emissions category and into the emissions compliance obligation category. PG&E does not oppose the inclusion of these emissions in the cap and trade program. Rather, we are concerned that this change is being made retroactively, applying to emissions as of January 1, 2014, particularly, when we received notice of this change when the 15-day language was released. We were working very closely with our gas operations team to achieve the ultimate goal of reducing our emissions. However, we feel that effective public policy would apply changes to regulated emission sources on January 1 of the year following the change. In this case, January 1, 2015. (PGE 5)

> **Response:** ARB staff agrees that adequate notice was not provided to underground storage facilities to be covered as of January 1, 2014. Therefore, the compliance obligation on vented and fugitive emissions from underground storage facilities will not go into effect until January 1, 2015..

D-2.3. Comment: <u>Compliance Obligations for Renewable Fuels</u>

Section 92852.2 Emissions without a compliance obligation. ARB has added renewable diesel to the list of source categories that combustion of which does not count toward a covered entities compliance obligation. Although the intent of this section appears to reduce the compliance burden of biomass derived CO2, this section does not include certain renewable liquid fuels, such as cellulosic. ARB has a definition of "Renewable Liquid Fuels" which covers all renewable fuels including renewable diesel.

WSPA proposes that ARB add Renewable Liquid Fuels into the list since it will cover renewable diesel in addition to other renewable liquid fuels.

Recommendation: ARB should include all renewable liquid fuels rather than only renewable diesel, revising the text as follows: Section 92852.2 (a) 9. Renewable Liquid Fuels. (WSPA 5)

> **Response:** Staff recognizes that new innovative hydrocarbon-based diesel fuel substitutes, like renewable and synthetic diesel fuels, are available in the market. Renewable diesel fuel is now included as one of the biofuels that, when combusted, does not result in emissions with a compliance obligation. At this time, ARB staff considers the definition of renewable liquid fuels to be too general and non-specific to include in section 95852.2. ARB staff only includes specific fuels in section 95852.2 after careful consideration and will not include a broad category of fuels that might allow for unintended fuel types to qualify as exempt from a compliance obligation. Additionally, unless the fuel is identified as covered in section 95812(d)(1) it would not have a compliance obligation, and there is no way to quantify emissions because of a lack of emission factors in MRR so renewable liquid fuels are already exempted by omission. Staff will work with stakeholders on the appropriate treatment of renewable liquid fuels in the future.

E. ELECTRICITY

E-1. Imported Electricity

First Point of Receipt

E-1.1 Multiple Comments: LADWP supported CARB's proposed changes in its discussion draft released on January 31, 2014 which clarified the definition of First Point of Receipt as the generation source specified on the NERC e-tag. The proposed definition would have been consistent with the definition of First Point of Receipt in the MRR and as CARB stated in its Final Statement of Reasons for the MRR, the revised definition would also result in consistent reporting between 2012 and 2013 compliance years.

The First Point of Receipt definition in the formal 15-day changes appears to be inadvertently changed such that key words used to define the term are now missing. Please reinstate the language per the January 31, 2014 discussion draft. (LADWP 3)

Comment: First Point of Receipt: At section 95802(a)(147), ARB has amended the definition of "First Point of Receipt." As proposed, the definition is not consistent with the definition in the Mandatory Reporting Regulation ("MRR") section 95102(a)(176) and should be amended for consistency. (SEMPRA 3)

Comment. Section § 95802(a)(147): Definition of “First Point of Receipt”

SDG&E and SoCalGas have proposed minor clarifying language to the definition of “First Point of Receipt” in Section 95802(a)(147) to improve readability as follows:

> “First Point of Receipt” means ~~the, where~~ defined points that have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag. (SEMPRA 4)
>
> **Response:** The proposed amendment to the definition of “First Point of Receipt” was made to ensure the definition in the Regulation is consistent with definition in MRR. The 15-Day Modification to the definition returns the definition back to the previous definition in the July 2013 effective version of the Regulation.

Emergency Power

E-1.2. Comment: As LADWP has stated before in its previous comments, the emergency assistance provision in the definition should not only apply to the “Independent System Operator” but all California balancing authorities. Exempting the GHG obligation associated with emergency energy imported by the California Independent System Operator (CAISO) unfairly shields the utility members of CAISO from reporting a GHG burden associated with such occurrences, whereas utilities in other California balancing authorities will be required to report their GHG emissions associated with imported emergency energy. There are a number of other balancing authorities in California including Los Angeles Department of Water and Power (also known as LDWP) that are also subject to the emergency preparedness and operations reliability standards of the NERC and the Western Electricity Coordinating Council. GARB should treat all balancing authorities equally.

Thus, LADWP recommends the following language in underline/strikeout format: "Imported Electricity does not include electricity imported into California by an ~~Independent System Operator~~ Balancing Authority to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council."

This recommended change would not require additional language defining "Balancing Authority" as it is already defined in §95802(30) whereas "Independent System Operator" is undefined. (LADWP 3)

> **Response:** ARB staff declines to make this change. CAISO does not meet the definition of an electricity importer because CAISO is not a purchasing selling entity. Additionally, CAISO does not participate in the allowance market like other California utilities, which are also BAAs. Utilities that are balancing authority areas participate in the market to buy and sell power and participate in the allowance market; therefore, any electricity imported into California by these utilities would have a compliance obligation under the Cap-and-Trade Program, even if it was imported for purposes of emergency power.

RPS Adjustment, REC Retirement Requirement

E-1.3 Multiple Comments: LADWP appreciates CARB's efforts over the past year to work with electric utility entities to modify the timing with respect to an entity claiming the RPS adjustment such that electric utility entities will not be required to prematurely retire their Renewable Energy Credits (REGs) under the California Energy Commission's Renewable Portfolio Standard (CEC RPS) Program. Although GARB's latest amendment adopted by its Board on October 24, 2013 no longer requires an electric utility to prematurely retire its REGs, LADWP believes that the RPS Adjustment credit should be claimed based on REC serial numbers reported under the MRR, rather than retirement of the REGs. LADWP outlined the reasons for the appropriateness of using REC serial numbers in its February 14, 2014 comment letter.

LADWP proposes the following changes to proposed §95852(b)(4)(B):

The RECs associated with the electricity claimed for the RPS adjustment must be <u>reported and verified pursuant to MRR.</u> ~~placed in the retirement subaccount of the entity party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25 and designated as retired for the purpose of compliance with the California RPS program within 45 days of the reporting deadline in section 95103(3) of MRR for the year which the RPS adjustment is claimed.~~

If CARB proceeds with their current approach (tying the RPS Adjustment credit to retirement of REGs), the restriction on when REGs can be retired (within 45 days of the reporting deadline in §95103(3) of MRR) should be removed. Per CEC RPS Program rules, RECs may be placed into the retirement subaccount *anytime during the year* but must be retired within 36 months of the month the renewable electricity was generated. For example, a REC generated in January 2013 must be retired by January 2016. The proposed amendment "within 45 days of the reporting deadline in section 95103(e) of MRR" can be interpreted such that this requirement is too restrictive allowing only RECs retired during the April 15 to July 15 window for the RPS Adjustment, but would exclude RECs retired outside of that window (July 16 to December 31 and January 1 to April14). A strict interpretation of this amendment would not satisfy the intent of the RPS Adjustment, which was to offset the compliance obligation for renewable energy that is not directly delivered into California, regardless of when the RECs are retired. All eligible RECs should be recognized for the RPS Adjustment, regardless of what time of year they are placed into the retirement subaccount. (LADWP 3)

Comment: IN ORDER TO ENSURE CONSISTENCY WITH RPS RULES, SCE REQUESTS ADDITIONAL MODIFICATION TO REC RETIREMENT REQUIREMENTS FOR RPS ADJUSTMENT CLAIMS

> **Recommendation:** SCE appreciates the ARB's attempts to clarify the REC retirement requirements for RPS adjustment claims. SCE suggests that the ARB adjust the language further to ensure consistency with the compliance timeframe established under California's RPS program. Specifically, SCE suggests the following modifications (in **bold**) to Section 95852(b)(4)(B) of the 15-Day Modifications:
>
> The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity subject to the California RPS, and party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25 ~~and designated as retired for the purpose of compliance with the California RPS program~~ within 45 days of the reporting deadline specified in section ~~95111(g)~~ **95103(e)** of **the** MRR for the year for which the RPS adjustment is claimed. **The RECs must be designated as retired for the purpose of compliance with the California RPS program on a schedule consistent with the rules governing that program.** (SCE 4).

Comment: WPTF greatly appreciates the proposed modifications to language in section 95852(b)(4) regarding requirements for use of the Renewable Portfolio Standard

(RPS) Adjustment. In particular, modification of the contractual requirements to allow an importer to have contract for renewable electricity or a contract with an RPS obligated entity that has ownership or contract rights to the renewable electricity will better align with normal business practices under the RPS program.

Additionally, staff have modified the renewable energy credit (REC) retirement obligation so that the REC must be moved into the retirement subaccount of the RPS obligated entity within 45 days of the reporting deadline for the year for which the RPS adjustment is claimed. This change is helpful in that it would effectively allow an importer to import firming and shaping energy one year, then take the RPS adjustment in a later year when the REC is retired. However, we remain concerned that it would require 'carrying' of a carbon cost for firming and shaping energy until such a time that associated RECs are retired pursuant to RPS program rules. While carrying of the carbon cost may not be difficult for large utilities, it would be challenging for energy service providers and create an unnecessary disconnect between the reported carbon obligation and actual energy transactions. (WPTF 3)

Comment. Noble Americas Energy Solutions LLC ("Noble Solutions") has offered comments on the RPS Adjustment no fewer than six times, most recently on February 14, 2014. Until the recent modifications to Section 95852(b)(4)(B) of the Cap-and-Trade Regulation, Nobel's concerns have largely gone unaddressed. With the issuance of the March 21, 2014 amendments, at least some modest progress has been made. But Noble Solutions remains concerned that even the amended RPS Adjustment rule fails to give appropriate deference and comity to the California RPS statute.

The argument is simple. RECs acquired in firming and shaping transaction under PU Code Sec. 399.16(b)(2) have all the attributes specified in the RPS statute, including the three-year life of the REC specified in PU Code §399.21(a)(6). The RPS Adjustment, as applied, deprives the owner of such a REC the full value of the REC by imposing a cost for keeping the REC for its full 36-month term before retiring that REC for compliance in accordance with the RPS statute. Not only is this an impermissible taking, it is a violation of the fundamental principle that an agency rule cannot contravene a statute.

Noble Solutions has requested that a Statement of Reasons, a common feature of the CARB rulemaking process, address the CARB staff's concerns about the RPS adjustment, but none accompanied the most recent amendments to the RPS Adjustment rule. If CARB staff is concerned about the potential for secondary trading of RECs used for the RPS adjustment, that concern can be addressed in a way that does not perpetuate the mismatch between compliance with carbon rules and RPS requirements. Under the proposed 15-day regulation, should a retail seller choose not to use RECs for RPS Adjustment for the year in which the import occurred, the retail seller could potentially be subject to a carbon obligation due to the declining Category 2 requirements under the RPS statute. Noble Solutions has previously shown that a REC claimed for the RPS Adjustment can be tracked by its own unique identification number through to the point of retirement—whenever that may occur—using existing documentation. It is simple to require that a REC used for the RPS Adjustment must be retired for compliance by the same entity that claimed the RPS Adjustment. But it is manifestly unreasonable to create a carbon compliance regime that requires an import associated with a REC contract to carry a carbon liability because the regulations are not in conformance with the RPS statute.

Noble Solutions stands ready to propose additional ways to address any other of CARB staff's concerns about the RPS Adjustment, if those concerns are made plain in writing. Burdening RECs with a carbon obligation is surely not the only way to ensure a robust carbon accounting system. Noble Solutions is convinced that permitting the flexibility afforded by state law will not damage the integrity of the carbon reporting protocols. A modest amendment to Section 95852(b)(4)(B) will preserve the compliance flexibility granted by the RPS statute, while maintaining CARB's goals of rigorously monitoring the RECs used for the RPS Adjustment.

(B) The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity subject to the California RPS, and party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25, and designated as retired for the purpose of compliance with the California RPS program ~~within 45 days of the reporting deadline specified in section 95111(g) of MRR for the year for which the RPS adjustment is claimed~~. <u>in accordance with state law</u>. (NOBLE 2)

Comment. ARB also proposes to amend CTR subsection 95854(b)(4)(B). For clarity of the amendments to that subsection, Powerex requests that ARB explicitly address the following response it provided in the October 2011 FSOR:

… The RPS adjustment applies to electricity procured, during the same data year from eligible renewable facilities to meet the requirements of California's RPS program. The equation for the calculation of the RPS adjustment that allows a reduction of covered emissions is based on the default emission factor for unspecified sources, pursuant to MRR. We require the same data year because our program is based on annual emissions reported to support the implementation of triennial compliance periods, in which there are annual surrender requirements.

Oct. 2011 FSOR at 2110. Powerex interprets the currently proposed amendment to modify the previous condition that the RPS adjustment was only claimable for the same data year in which the electricity from the eligible renewable facility was procured. If Powerex's interpretation is correct, we propose that the following be included in the 2014 FSOR:

Subsection 958545(b)(4)(B) no longer limits the reporting entity's ability to claim the RPS adjustment to "the same data year" but rather allows the RPS adjustment to be claimed in a later data year provided that the REC retirement conditions of section Subsection 958545(b)(4)(B) (as well as other relevant sections of the regulation) are met. (POWEREX 2).

Comment: Section 95852(b)(4) – RPS Adjustment: NCPA supports the proposed revisions to the Regulation that confirms the ability of EDUs to utilize the RPS Adjustment as intended. Revisions to section 95852(b)(4) now specifically reference the state's RPS program, change the timing for retirement of RECs, and note that such retirement is "for the year in which the RPS adjustment is claimed," rather than "in the year." These changes better reflect the interrelationship between the Cap-and-Trade Program and the RPS program, better capture the intent of the provision as noted in the original Final Statement of Reasons, and should be adopted. In order to better address the functionality of the RPS programs, however, the provisions linking REC retirement to the MRR reporting deadline should be removed. As the program matures, NCPA urges CARB to review the language in subsequent rulemakings to ensure that the stated intent of the provision is carried out and that the regulatory language does not have the unintended consequence of adversely impacting covered entities' ability to comply with the RPS requirements or result in additional cost burdens for EDU ratepayers. (NCPA 3)

> **Response:** The proposed modifications to require REC retirement for RPS adjustment is to clarify the original intent that timing of the REC retirement be consistent with the reporting requirements in MRR.
>
> Importers are able to claim the RPS adjustment any time during the 36 month period allowed for under RPS. The addition of the language tying the timing of reconciling REC retirement to MRR reporting requirements is to clarify the eligibility of RECs generated as a result of electricity generation towards the end of the GHG reporting period.
>
> The requirements in the proposed amendments are consistent with RPS requirements to ensure that eligible renewable electricity claimed by an importer, under the RPS adjustment calculation, was procured to meet the utility's RPS requirement. To prove this requirement is met and ensure that a REC is not further traded or sold after a Cap-and-Trade compliance obligation adjustment has been provided, a utility must place the REC into the WREGIS retirement subaccount.
>
> Staff does not agree that reporting of REC serial numbers with a future commitment to retire RECs provides environmental integrity under the Cap-and-Trade Program as there is no mechanism in the Cap-and-Trade Regulation or MRR to verify the future retirement for an adjustment to a current compliance obligation. And there is no mechanism to retroactively adjust a compliance obligation if a utility did not retire the REC to meet RPS as promised.

E-1.4. Comment: Proposed CTR Subsection 95852(b)(4) Regarding the Renewable Portfolio Standard ("RPS") Adjustment. Powerex supports the currently proposed additional modifications to CTR subsection 95854(b)(4)(A)(2), which amend the provision to eliminate the previously proposed requirement that an importer have a contract with an RPS-covered entity that assigns rights to the renewable energy certificates ("RECs") associated with the delivery of electricity covered by that contract to the RPS-covered entity. Powerex is appreciative of staff effort and consideration of the issue. (POWEREX 2)

Response: Staff appreciates the comment.

Compliance Obligation for Voluntary Purchases of Renewable Electricity that is not able to be Delivered to California

E-1.5. Comment: In addition, LADWP believes that RECs for renewable electricity imported for voluntary green power programs should also receive credit to offset the cap-and-trade compliance obligation. By limiting the RPS adjustment credit to only RECs that are retired in the CEC's RPS accounting system, it will create a disincentive to having voluntary green power programs in California because paying the cap-and-trade compliance obligation on imported renewable energy would increase costs to the electric utility and its customers.

Recommendation: LADWP proposes the following alternative language for proposed §95852(b)(4)(B):

The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.25 and designated as retired for the purpose of compliance with the California RPS program at any time until ~~within~~ 45 days following ~~of~~ the electric power entity reporting deadline in section 95103(e) of MRR during the same year for the year for which the RPS adjustment is claimed. If the RECs were created through voluntary renewable programs, the REC serial numbers must be reported and verified pursuant to MRR. (LADWP 3)

Comment: There are additional issues related to the RPS adjustment provision that LADWP believes should be addressed to 1) fulfill the original intent of the RPS adjustment provision and 2) recognize renewable electricity imported on behalf of green power program customers.

If the RPS Adjustment is intended to neutralize the GHG emissions reported for imported Bucket 2 renewable energy (so that it is treated as zero GHG emission energy under the cap-and-trade program), the credit needs to include both the default GHG emission factor (0.428 MT C02e/MWh) *and* the 2% transmission loss factor so that the difference between the reported GHG emissions for the imported electricity and the RPS Adjustment credit is equal to zero. Currently, the RPS Adjustment gives credit only for the default GHG emission factor but does not provide credit for the 2% transmission loss factor that is applied along with the default GHG emission factor when the imported Bucket 2 renewable energy is reported under the MRR. The result is a 2% deficit in the RPS (LADWP3)

Comment: In addition, an electric utility may procure and import renewable energy on behalf of its green power customers, who are not "entities subject to the California RPS."

Recommendation: Thus, LADWP proposes the following language for §95852(b)(4)(A)(2):

A contract with an entity subject to the California RPS that has ownership or contract rights to the electricity and associated RECs generated by the eligible renewable energy resource, as verified pursuant to MRR or a <u>*contract to procure electricity generated by an eligible renewable energy resource and the associated RECs on behalf of California electric utility customers that participate in voluntary green energy programs as verified pursuant to MRR.*</u> (LADWP 3)

Response: This comment is beyond the scope of the proposed amendments. The Cap-and-Trade Program is designed to incentivize renewable electricity and ARB would like to continue to support further development of renewable electricity sources. Staff will discuss this issue further with stakeholders to determine whether this is something that should be addressed in a future rulemaking.

RPS Adjustment, Transmission Line Loss Factor

E-1.6. Comment: Adjustment credit such that the credit does not completely cover the reported GHG emissions for the imported Bucket 2 renewable energy. The consequence of not including credit for the 2% default transmission loss factor in the RPS Adjustment is assigning cap-and-trade compliance costs to renewable energy for default GHG emissions that are not real.

Recommendation: To provide full credit for renewable energy, LADWP proposed the following revision to section 95852(b)(4)(C)

The quantity of emissions included in the RPS adjustment is calculated pursuant to MRR as the product of the default emission factor for unspecified sources, <u>*the transmission loss correction factor for unspecified sources*</u>*, and the reported electricity generated (MWh) that meets the requirements of this section, 95852(b)(4).* (LADWP 3)

Response: This comment is beyond the scope of the proposed amendments. Staff will discuss this issue further with stakeholders to determine whether this is something that should be addressed in a future rulemaking.

REC Retirement and Double Counting

E-1.7. Comment: Thank you for addressing many of the comments we submitted in October 2013 during the previous comment period. There is one major area of our comments that was not addressed, and we wish to bring it to the attention of the ARB as it considers final updates to the regulation.

The current draft retains a change originally presented in the September 2013 revisions of the document, which relates to the criterion for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emissions factor in Sec. 95852(b)(3)(D). This change was from “RECs must be retired” to “REC serial numbers must be reported”. This change appears to be appropriate only provided that:

1) The importer is not itself delivering to load, and
2) The REC stays in state and the electricity is not wheeled out of state as zero emissions electricity.

If the importer is delivering directly to end users, including for the RPS, then retirement of the REC should be required to prevent double counting.

If the REC is traded out of state by the importer, an in-state LSE, or other entity after the REC has been reported by the importer (to avoid a compliance obligation), then there is double counting. The electricity imported with the REC entered the state as renewable with no requirement to retire allowances, but when the REC is consumed for out of state load the electricity with which it was imported should no longer be treated as renewable, and the electricity should have emissions associated with it (required to buy allowances). The REC is the means to track and claim the renewable nature of the electricity, and if the REC is not used for California load then the electricity imported can only be identified as system power.

Only in the case that the importer is not delivering to load and simply using the REC to prove that the electricity was delivered into the state without emissions (avoiding compliance obligations) and when the REC is exclusively traded and used in state is “reporting” sufficient. The in-state LSE isn’t regulated for imports, so there wouldn’t be double counting of the REC under the cap-and-trade in this case.

> **Recommendation:** We suggest that the language of the Sec. 95852(b)(3)(D) be amended further to include the underlined text: “If RECs were created for the electricity generated and reported pursuant to MRR, then the REC serial numbers must be reported and verified pursuant to MRR and shown to be used in California.” (CRS 2)
>
> **Response:** The proposed amendments to section 95852(b)(3)(D) are required to treat in-state and out-of-state generation similarly. ARB staff declines to make the suggested modifications requiring retirement of RECs because the REC does not determine the emissions factor. Emissions from specified sources are determined by the technology and fuel source used for the electricity generation,

and not by the REC. The REC is used by other California state agencies to track RPS eligibility and compliance. ARB staff will post a list of RECs associated with specified imports to ensure there is no double counting of environmental attributes.

For clarification, the definition of a wheel requires the electricity to move continuously without sinking in California, or creating a break in the NERC e-Tag. There is no compliance obligation for electricity that is wheeled through the state.

E-1.8. Comment: CRS also seeks clarification on the following points:

- Please clarify how double counting will be avoided if the REC is sold out of state or power is wheeled out of state as zero emissions after "reporting" by the importer per Sec. 95852(b)(3)(D). How will ARB track the REC to make sure it stays in state and, in the case that the power is wheeled out of state, how will ARB prevent double counting? WREGIS may be of use for this purpose, if there is a way to indicate on the REC that it was reported with imported electricity (without retiring it).
- Please also clarify when this reporting will occur, and when the serial numbers will be posted publically. We suggest that public posting of serial numbers occur (or that these serial numbers be otherwise made publically available) in as close to real time as possible. If there is a time lag, there may be several other parties that transact the REC before it is made known that it only has GHG value if used within California. (CRS 2)

Response: ARB staff will post the REC serial numbers on its website so that others can determine whether a REC they are considering purchasing contains all of the attributes they intend. The reporting deadline for electricity importers is specified in the MRR as June 1. Serial numbers will be posted after verification as close to real time as possible to minimize any time lag.

E-2. Resource Shuffling

Comments Outside of the Scope of the 15-Day Changes

E-2.1. Comment: We support the inclusion of the resource shuffling provisions that incorporate the current guidance language and remove the attestation requirements. (NCPA 4)

> **Response:** Although the comment is outside the scope of the 15-day changes, staff thanks the commenter for the support.

E-2.2. Multiple Comments. Clarification of Proposed CTR Subsections 95802(a)(338) and 95852(b)(2) Regarding the Prohibition on Resource Shuffling. On October 23, 2013, Powerex submitted comments on the proposed amendments to the CTR considered by the Board at its October 2013 meeting ("Powerex's October letter"). Among other issues, Powerex's October letter addressed proposed changes to the rules governing resource shuffling. However, ARB has not made any clarifying amendments or additions to the resource shuffling modifications now proposed. Powerex continues to support ARB's ongoing effort to provide clarity and specificity to the rules prohibiting resource shuffling, but Powerex believes that further clarification is necessary on a few specific and important issues.

In Powerex's October letter, we requested clarification that the resource shuffling prohibition does not apply to transactions and deliveries within an ACS's system. In its October letter, Powerex suggested that ARB address this uncertainty by adding an additional "safe harbor 14" to exempt transactions and deliveries within an ACS system from the resource shuffling prohibition. If ARB chooses not adopt the proposed additional safe harbor, Powerex specifically requests that in the upcoming Final Statement of Reasons for these CTR amendments (the "2014 FSOR") ARB confirm that: The resource shuffling prohibition does not apply to transactions and deliveries within an ACS's system that occur during the reporting year for which the entity has been designated as an ACS.

ARB can realize broad program benefits by providing the requested clarity, either in the 2014 FSOR or by further modification of the resource shuffling rule. Clarification of applicability of the resource shuffling prohibition to ACS entities will give assurance to current ACS entities, as well as those entities considering applying for ACS status, of the value of the ACS program. The ACS program provides ARB a more robust oversight framework, and ARB should not jeopardize the continued viability of this important tool by allowing the current regulatory uncertainty to persist. (POWEREX 2).

E-2.3. Comment. Resource Shuffling Definition Must Protect Legitimate Divestitures. M-S-R urges the Board to continue to monitor the application of the resource shuffling definition in section 95852(b)(2) to ensure that the State's broader and long-term goal of encouraging divestiture of coal-fired generation is not impeded. As previously noted, this is an important issue to M-S-R and other entities with ownership interests in coal-fired generation that are subject to the provisions of the California Emissions Performance Standard. M-S-R supports incorporation of the resource shuffling guidance language into the Regulation, but remains concerned that the definition may not adequately accommodate complex or non-traditional transactions that may result in a covered entity reducing its compliance obligation from out-of- state resources. It is important that covered entities not be penalized for legitimate business transactions that merely result in a reduction in the covered entity's compliance obligation. (MSR 2)

E-2.4. Comment. Modifications to the regulation proposed for Resource Shuffling language, while an improvement from prior versions, do not go far enough to provide sufficient clarity to the market. No further revisions have been proposed by CARB from the 45-day modification but the regulations still remain silent in several key areas that need be addressed in order to allow the energy markets to operate efficiently and to avoid negatively impacting liquidity for imported power. If CARB is unwilling to modify the regulation to address these concerns Brookfield requests that CARB provide the clarification in the Final Statement of Reasons ("FSOR"). Brookfield's concerns are summarized below. The detail behind these concerns and recommendations can be referenced in Brookfield's comments to the 45-day modifications submitted on October 16, 2013.

1. The definition and enforcement of resource shuffling must be explicitly limited to the activities of the First Deliverer and not extend to other entities' historic procurement practices
2. To ensure a buyer will not be held liable for other entities' resource shuffling activities, Brookfield requests that CARB proposes specific contract language that, if included in a bilateral contract or a pre-certification option, will ensure that a buyer will not be held liable for other entities' resource shuffling activities
3. The proposed safe harbors focus only on conditions under which California utility legacy contracts of high emissions power might be diverted. It is still unclear whether or not market activities outside of this definition are considered resource shuffling.
4. Proposed additions to the safe harbor language in 95852 (b)(2)(A)(9)for electricity imported under short-term contracts is problematic and should be deleted or further clarified in the FSOR. It is unclear how sales of other similar resources would be compared to or even be relevant towards evaluating a specific market transaction as part of a resource shuffling scheme.
5. CARB must define in the regulation or clarify in the FSOR what comprises a linked activity as it is used in Section 95852 (B)(2)(a)(10)
6. A transparent process is needed for the investigation and enforcement of alleged resource shuffling activity. CARB must include in the regulation or through a supplemental document what methods will be used to identify resource shuffling activities and what process would be followed to investigate a First Deliverer once the activity is identified. (BEM 2)

> **Response:** These comments are outside the scope of the 15-day changes, and therefore no further response is required.

E-2.5. Comment: (CULLENWARD 3)

April 4, 2014

Climate Change Program
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments on Proposed Cap-and-Trade Regulations, 15-Day Changes Resource Shuffling Safe Harbors — § 95852(b)

Thank you for the opportunity to comment on the proposed carbon market regulations. Please incorporate by reference my previous comment letter from October 23, 2013,[1] and its attachments.[2]

Once again, I write to express serious concerns that the resource shuffling safe harbors will cause significant quantities of greenhouse gas emissions to leak out of California's carbon market. Since my last comment letter, significant leakage has already occurred via three major transactions that appear to be permissible under the safe harbor policy. As a result, between 30 and 60 million tons of CO_2 have already leaked or are imminently leaking out of California's market.

These new results demonstrate that the proposed regulations are inconsistent with clear statutory directives from California's climate law, AB 32. In addition, they underscore ARB's failure to analyze the environmental impacts of the proposed regulatory changes as required under the California Environmental Quality Act.

1. ARB's proposed resource shuffling safe harbors contradict the purpose and requirements of AB 32.

A. The safe harbors have already caused and will continue to cause resource shuffling, resulting in significant leakage of greenhouse gas emissions to neighboring states.

The proposed regulations are fundamentally inconsistent with California's climate policy objectives because the resource shuffling safe harbors have caused and will continue to cause significant leakage of greenhouse gases to other states. In plain English, this

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1 Danny Cullenward, Proposed Amendments to the California Cap-and-Trade Program (September 4, 2013 Proposed Regulation Order). Comment letter to the California Air Resources Board (Oct. 23, 2013), *available at* http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade13.

2 Danny Cullenward, Don't let accounting tricks dominate the carbon market. San Jose Mercury News op-ed (Oct. 21, 2013), *available at* http://mercurynews.com/opinion/ci_24354840/danny-cullenward-dont-let-accounting-tricks-dominate-carbon; Danny Cullenward and David Weiskopf, Resource Shuffling and the California Carbon Market. Stanford Law School ENRLP Working Paper (July 13, 2013), *available at* http://law.stanford.edu/publications/resource-shuffling-and-the-california-carbon-market.

means that the cap-and-trade market will not actually reduce greenhouse gas emissions as planned. To the extent that regulated parties in California rely on resource shuffling to comply with climate policy, the carbon market will produce the false appearance of emissions reductions. Put another way, resource shuffling means that the cap is no longer firm.

California's climate law, AB 32, defines leakage as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."[3] Under this definition, any reduction in emissions within California that is caused by the transfer of emissions liability outside the state constitutes leakage.

The risk of leakage is arguably greatest in the electricity sector, where the problem is known as resource shuffling. For example, consider a California utility that imports specified power from a coal power plant in Arizona. If the California utility sells its interest in that power plant to a party that is not a covered entity in California's carbon market, the liability for those emissions will be transferred out of the State's carbon market system. Suppose the California utility then acquires replacement power from a natural gas power plant; meanwhile, the coal plant continues to produce power for its new owner.

As a result of these transactions, the California utility would report a reduction in greenhouse gas emissions. At the same time, that reduction would be offset by an increase in emissions of greenhouse gases outside the state. Critically, there would be no change in net emissions to the atmosphere. The liability for the high-emitting resource would have merely been transferred out of California's carbon market, allowing both the State and the covered entity to claim credit for emissions reductions that have not actually occurred.

Table 1: Resource Shuffling Example
(Using stylized greenhouse gas emissions units)

	California	Western State X	Total
Step 1	100	50	150
Step 2	50	100	150
Change	- 50	+ 50	0

Table 1 illustrates this example numerically. In the first step, the California utility owns a power plant and an out-of-state utility owns a natural gas power plant. For simplicity, assume the coal plant emits 100 units of greenhouse gases, whereas the natural gas plant emits 50 units of greenhouse gases; both produce the same amount of electricity and

[3] Cal. Health & Safety Code § 38505(j).

are located outside of California. Because first deliverers of electricity are liable for the emissions associated with their imports,[4] the California utility will initially report the coal power plant's emissions.

In the second step, the parties swap ownership interests in the two plants. As a result, the California utility reports a reduction in emissions that is offset by an increase in emissions outside the state, with no net change in emissions to the atmosphere. In this case, 50 units of greenhouse gas emissions have leaked out of California's system. Note that if this example involved a zero-carbon replacement resource (like nuclear or renewable energy) instead of natural gas, the leakage would be 100 units of greenhouse gas emissions.

1. The Safe Harbors Will Cause Significant Leakage.

Economists have repeatedly warned ARB that the proposed safe harbors effectively negate the prohibition on resource shuffling and will result in significant leakage. Previously, my colleague David Weiskopf and I estimated leakage impacts from resource shuffling of legacy coal power contracts, finding the potential for between 108 and 187 million tons of CO_2 through 2020.[5] That view is consistent with what ARB's independent Emissions Market Assessment Committee ("EMAC") economists have estimated. For example, a June 2013 EMAC report found that the likely range of leakage impacts from resource shuffling would be between 120 and 360 million tons of CO_2 through 2020, including both legacy coal contract shuffling and other forms of resource shuffling.[6] Another paper from University of California economists found that "even a modest weakening of the [rules and practices] targeted at limiting reshuffling will greatly undermine the strictness of the emissions cap through reshuffling."[7]

Under the proposed regulations, any transaction fitting a safe harbor is exempted from the prohibition on resource shuffling.[8] In case there is any doubt about the breadth of the safe harbors and their impacts, I review two here, using the numbering in the proposed regulations:

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4 Cal. Code Regs. tit 17, § 95852(b).

5 Cullenward and Weiskopf, supra note 2 at 27.

6 Severin Borenstein, James Bushnell, Frank A. Wolak, and Matthew Zarazoga-Watkins, Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market. Draft EMAC report 1, 14 (June 12, 2013).

7 James Bushnell, Yihsu Chen, and Matthew Zaragoza-Watkins, Downstream Regulation of CO_2 Emissions in California's Electricity Sector. Energy Institute @ Haas Working Paper #236, at 4, *available at* http://ei.haas.berkeley.edu/pdf/working_papers/WP236.pdf. The specific measures referred to in this quote refer to the treatment of legacy coal power import contracts and the extent to which zero-greenhouse gas resources like hydroelectricity can be resource shuffled. *Id.* at 10.

8 Proposed regulations amending Cal. Code Regs. tit. 17, § 95852(b)(2)(A).

6. Electricity deliveries that substitute for deliveries that have been discontinued because of termination of a contract or divestiture of resources for reasons other than reducing a GHG compliance obligation.[9]

7. Electricity deliveries that are necessitated by early termination of a contract for, or full or partial divestment of, resources subject to the EPS rules.[10]

The sixth safe harbor exempts from the definition of resource shuffling any transaction motivated by any purpose except avoiding the compliance costs of California's carbon market. This provides countless options for avoiding the resource shuffling prohibition. For example, covered entities could plausibly justify nearly any resource shuffling transaction by citing complimentary objectives, like reducing local air pollution impacts from their power imports, minimizing costs, or even something so mundane as diversifying contractual counterparties. As a result, ARB would have serious trouble bringing any enforcement actions because defendant parties would always be able to claim a plausible complimentary motivation. At best, enforcement actions would face a difficult evidentiary question; at worst, a reviewing court could conclude that the safe harbor protects all transactions where any alternative rationale is present.

If the sixth safe harbor is unnecessarily vague, the seventh safe harbor offers an explicit loophole. It unambiguously exempts any transaction that involves divestment of resources subject to the EPS rules, referring to the emissions performance standard set by SB 1368. Presumably ARB's intent is to allow California entities to exit their interests in legacy coal contracts, which, as described above could result in more than 100 million tons of CO_2 leaking out of the market. As written, however, the safe harbor goes even further and provides an almost unlimited protection to all major utility power contracts.

By defining the seventh safe harbor by reference to any divestment of resources subject to the EPS rules, ARB would exempt any transaction involving both utilities and long-term baseload power contracts. Technically, the EPS applies to "load-serving entities" and "local publicly owned electric utilities."[11] The EPS prohibits "long-term financial commitments," which are defined as either "new ownership investment[s] in baseload generation or a new or renewed contract with a term of five or more years, which includes procurement of baseload generation."[12] Thus, the seventh safe harbor would even exempt any transaction involving a utility and a long-term baseload power contract or ownership interest; even divestment of natural gas facilities would be permissible.

As these examples demonstrate, the safe harbors effectively undo the prohibition on resource shuffling. Therefore, if the proposed regulations are adopted, covered entities in

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9 *Id.* § 95852(b)(2)(A)(6).

10 *Id.* § (b)(2)(A)(7).

11 Cal. Public Utilities Code §§ 8340(h)-(i).

12 *Id.* § 8341(a) (the prohibition); *id.* § 8340(f) (the definition).

the electricity sector would be officially free to engage in transactions that would leak tens to hundreds of millions of tons of greenhouse gas emissions to neighboring states.

2. The Safe Harbors Have Already Caused Significant Leakage.

ARB will formally undermine its prohibition on resource shuffling if it adopts the proposed regulations. In practical terms, however, ARB already undermined the carbon market's integrity with its November 2012 informal guidance on resource shuffling.[13] The current administrative process would simply codify the changed regime ARB introduced then, as that document lists the very same safe harbors proposed here.

It should come as no surprise, then, that several major resource shuffling transactions have already occurred. Because these transactions all involve or relate to baseload electricity contracts—specifically, divestment from legacy coal power contracts—they appear to be entirely permissible under the broad safe harbors as articulated in ARB's regulatory guidance document. The three transactions are described below, offering further indication of the environmental and economic impacts of ARB's proposed regulatory reforms.

- **Southern California Edison / Four Corners Units 4 & 5.**

  At the end of December 2013, Southern California Edison completed the sale of its interests in the coal-fired Four Corners power plant in Arizona to APS, a utility based in Arizona.[14] As a result of the transaction, SCE will report a reduction in emissions in the California carbon market because whatever replacement power SCE secures will have lower emissions than conventional coal power. In turn, the Arizona utility's emissions profile will increase. Thus, this transaction caused emissions to leak out of California's carbon market.

- **California Department of Water Resources / Reid Gardner Unit 4.**

  Pursuant to its Climate Action Plan,[15] the California Department of Water Resources terminated a contract with Reid Gardner Unit 4, a coal-fired facility in Nevada. DWR's original contract term ended in July 2013, at which point the Department elected not to renew the contract with the plant's owner, Nevada Power

13 California Air Resources Board, Cap-and-Trade Regulation Instructional Guidance, Appendix A: What is Resource Shuffling? (November 2012), *available at* http://www.arb.ca.gov/cc/capandtrade/guidance/appendix_a.pdf.

14 APS Press Release, APS completes purchase at Four Corners power plant (Dec. 31, 2013), *available at* https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-completes-purchase-at-four-corners-power-plant.aspx.

15 California Department of Water Resources, Climate Action Plan, Phase I: Greenhouse Gas Emissions Reduction Plan (May 2012). Note that terminating the Reid Gardner contract accounts for approximately 80% of the Department's planned emissions reductions. *Id.* at 10, Table S-1 (estimating that by 2020, DWR will have reduced 882,700 mtCO_2 per year by terminating the Reid Gardner, compared to 1,116,730 mtCO_2 per year from all measures combined).

Company. DWR will report a reduction in emissions in California, likely from using replacement power from the new natural gas-fired Lodi Energy Center in California.[16] Nevada Power Company will continue to operate Reid Gardner Unit 4, resulting in an increase in emissions outside of California.[17] Thus, this transaction caused emissions to leak out of California's carbon market.

- **Los Angeles Department of Water and Power / Navajo Generating Station.**

Earlier this year, the Los Angeles Department of Water and Power approved the purchase of a natural gas-fired power plant in Nevada called the Apex Power Plant. According to regulatory filings, this facility was purchased as part of LADWP's plan to divest its interest in the Arizona-based, coal-fired Navajo Generating Station in 2015, prior to the end of its contract term in 2019.

Because LADWP has not yet divested—and therefore cannot report emissions reductions within California—this transaction does not yet constitute resource shuffling. Nevertheless, it contains a candid and telling admission from LADWP. In a regulatory filing with the Los Angeles City Council, LADWP states that divesting from the Navajo Generating Station will reduce its CO_2 emissions liability, **"relieving LADWP from having to purchase emission credits to comply with the statewide cap and trade program."**[18]

Indeed, this appears to be a textbook example of "a plan, scheme, or artifice to receive credit for emissions reductions that have not occurred"—the very definition of resource shuffling currently on the books.[19] Yet it clearly fits within several of the safe harbors in the guidance document and for this reason would not violate the proposed regulatory amendments.[20]

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16 *Id.* at 58 (indicating that DWR has a 33.3% interest in the Lodi Energy Center and plans to use those imports to replace the lost deliveries from Reid Gardner). According to DWR, this facility is 16% more efficient than ARB's default unspecified emissions factor (361 vs. 428 $mtCO_2e/GWh$). *Id.*

17 Nevada recently passed SB 123, a law that requires Nevada Power Company to retire 300 MW of coal-fired capacity by the end of 2014, and an additional 250 MW by the end of 2017. This has generally been interpreted to mean closing Reid Gardner Units 1, 2, and 3 (each 100 MW) in 2014, and Reid Gardner Unit 4 (250 MW) in 2017. Leakage will continue until Reid Gardner Unit 4 retires.

18 Los Angeles Department of Water and Power, LADWP Board Approval Letter re: LADWP Apex Power Project Power Sales Agreement (PSA) No. BP 13-055 (Nov. 26, 2013), at 3, *available at* http://cityclerk.lacity.org/lacityclerkconnect/index.cfm?fa=ccfi.viewrecord&cfnumber=13-1635.

19 Cal. Code Regs., tit. 17, § 95802(a)(252).

20 For example, LADWP cites several other motivating factors behind its decision to divest—such as the expectation of better prices from selling the coal contract early, and the intention to subsequently increase renewable energy and energy efficiency resources—and would therefore likely meet the sixth safe harbor conditions. LADWP, supra note 18 at 3. In any case, the transaction involves replacement power LADWP could argue "is necessitated by" divestment of a resource subject to the EPS rules, clearly satisfying the seventh safe harbor.

> Once divestment from the Navajo Generating Station occurs as planned, LADWP will report a reduction in emissions within the California market. In turn, emissions outside the state will increase. Thus, LADWP's stated intention to shift the liability for its legacy coal resources to unregulated parties and report an emissions reduction due to its purchase of relatively clean replacement power indicates a firm intention to cause leakage.

These three transactions demonstrate that greenhouse gas emissions are already leaking out of California's carbon market at scale. As a result, between 30 and 60 million tons of CO_2 have leaked or are imminently leaking out of California's carbon market. Full calculations are presented in Tables 2 through 5, contained in the Appendix to this letter.

B. The safe harbors violate AB 32's clear requirement that ARB regulations minimize leakage. (Cal. Health & Safety Code § 38562(b)(8))

California's climate law speaks directly to this carbon market design issue. AB 32 requires that "to the extent feasible," ARB "shall ... minimize leakage."[21] Here, the proposed regulations effectively undo the formal prohibition on resource shuffling. Because resource shuffling has caused and will continue to cause significant leakage of greenhouse gas emissions to other states, the proposed regulations to do not minimize leakage.

A regulation that does not minimize leakage would be permissible under AB 32 only if there are no feasible alternatives. In this case, however, ARB has a wealth of alternative options. First, ARB could strike the proposed safe harbors and leave in place the original prohibition on resource shuffling in its regulations. Second, ARB could write new regulations that increase compliance flexibility while preventing leakage in cross-border electricity transactions. For example, ARB could require covered entities to retain emissions liability when shifting major electricity contracts to unregulated, out-of-state parties.[22] Third, ARB could lower the overall cap under AB 32 to reflect observed and anticipated leakage, such that the net reduction after leakage meets the 2020 emissions target.

As these options demonstrate, ARB has a number of feasible alternatives—including doing nothing at all to the existing regulations. ARB's decision to nevertheless encourage leakage through the codification of safe harbors can only be described as arbitrary and capricious.

Because (1) the safe harbors have caused and will continue to cause significant leakage, and (2) ARB has a range of feasible alternatives, the proposed regulations do not minimize leakage as required by state law.

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21 Cal. Health & Safety Code §§ 38562(b), (b)(8).

22 For a fully developed regulatory text implementing this approach, *see* Cullenward and Weiskopf, supra note 2, Appendices I & II.

C. The safe harbors violate AB 32's clear requirement that ARB regulations produce emissions reductions that are real, permanent, quantifiable, verifiable, and enforceable. (Cal. Health & Safety Code § 38562(d)(1))

By definition, leakage creates emissions reductions that are not real because when leakage occurs, the associated emissions reductions reported in California do not cause net emissions reductions to the atmosphere. Instead, they merely indicate the transfer of emissions liability to unregulated, out-of-state parties. Accordingly, the reported emissions reductions due to emissions reductions are not real, permanent, accurately quantified, or verifiable. Even if ARB technically preserves its prohibition on resource shuffling, the safe harbors render it unenforceable. Thus, the safe harbors also violate AB 32's requirement that emissions reductions be "real, permanent, quantifiable, verifiable, and enforceable."[23]

2. ARB's environmental analysis is legally insufficient because it fails to acknowledge the significant environmental harms caused by the safe harbors.

Although the proposed amendments are problematic enough on their own, ARB's failure to acknowledge the expected—and quite likely intended—consequences of its actions is all the more troubling. ARB's September 2013 Staff Report on the current proposed regulations contains an environmental analysis for the proposed regulations.[24] This analysis brazenly relies on misleading comparisons to avoid assessing the environmental impacts of the proposed regulatory changes. It must be updated to serve the most basic purposes of the California Environmental Quality Act ("CEQA"), which are to:

(1) Inform governmental decision makers and the public about the potential, significant environmental effects of proposed activities.

(2) Identify ways that environmental damage can be avoided or significantly reduced.

(3) Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.

(4) Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.[25]

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23 Cal. Health & Safety Code § 38562(d)(1).

24 California Air Resources Board, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Staff Report: Initial Statement of Reasons 1, 44 (Sept. 4, 2013).

25 Cal. Code Regs tit. 14, §§ 15002(a)(1)-(4).

Even as it implements major reforms that undermine the economic and environmental integrity of the carbon market, ARB nevertheless manages to stay silent on the expected environmental impacts. ARB's 2013 Staff Report falsely construes the proposed safe harbors as mere "clarifying language" that "would not affect the compliance responses available to [covered] entities from what was analyzed in the 2010 FED."[26] That reliance is misplaced because the 2010 FED analyzed a rulemaking that produced the original prohibition on resource shuffling, which did not include any safe harbors. In other words, ARB falsely claims that the current proposed safe harbors do not affect its prohibition on resource shuffling.

This is simply incorrect. The current regulation says only that "[r]esource shuffling is prohibited and is a violation of [Article 5 of the Cap-and-Trade Regulations]";[27] it says nothing about thirteen broad exemptions to this supposedly-preserved rule. As a result of the proposed safe harbor provisions, ARB's prohibition on resource shuffling will become an unenforceable formality. Between 30 and 60 million tons of CO_2 have leaked or are imminently leaking as a result, exceeding any reasonable threshold for significance under CEQA.[28] Because the proposed safe harbors would radically modify the carbon market regulations as they currently exist, CEQA requires ARB to conduct an analysis of the environmental impacts.[29]

By claiming that it is not, in fact, changing its market rules, ARB suggests that adding multiple loopholes that undermine a critical market rule will have no environmental effect on the performance of its cap-and-trade market. Yet as my previous comment letter, ARB's own economic advisers (EMAC), and the observed resource shuffling transactions described in this letter show, the proposed regulatory changes have caused and will continue to cause significant leakage. In turn, this will lead to significant environmental consequences, as ARB put it when addressing leakage in its 2010 FED:

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26 California Air Resources Board, supra note 24 at 51 (citing California Air Resources Board, 2010 Cap and Trade Regulation, Appendix O: Functional Equivalent Document 1, 1 (Oct. 28, 2010)). ARB concludes its 2013 Staff Report analysis by stating that:

> "Resource shuffling was disclosed as a prohibited activity in the 2010 Regulation as analyzed in the 2010 FED. Therefore, the potential for adverse impacts associated with the proposed clarifications to this definition fall within the scope and scale of those previously analyzed."

Id. at 59.

27 Cal. Code Regs. tit. 17, § 95852(b)(2).

28 *See* Cal. Code Regs. tit. 14, § 15064.4 (providing guidelines for determining the significance of impacts from greenhouse gases for the purposes of CEQA analysis).

29 ARB could argue that the current regulatory proposal will have no significant changes to the status quo, but only if it acknowledges that the safe harbor regime is already in effect due to the November 2012 regulatory guidance document. Yet that admission would raise serious questions as to whether introduction of the regulatory guidance document constituted impermissible underground regulation that avoided the basic requirements of California administrative law, such as offering the public with formal notice and an opportunity to comment.

> "If leakage occurs, the reductions in GHGs achieved by sources in California may be undone by a corresponding increase in emissions outside of California .... [Leakage] would likely lead to increased adverse environmental impacts outside of California, and would have negative effects on California's economy."[30]

Because the resource shuffling safe harbors have caused and will continue to cause significant environmental consequences—impacts ARB has never acknowledged or analyzed—ARB has not satisfied the basic requirements of CEQA. To comply, ARB must assess the environmental consequences of its proposed safe harbor regulations and evaluate the feasibility of alternative approaches.

3. ARB can still pursue solutions, but must first acknowledge the problem.

Although the safe harbors have already created significant leakage, ARB can still act to fix the problem. There are at least two solutions. First, ARB could estimate the observed and anticipated leakage resulting from unfettered resource shuffling, and lower the overall cap such that the net emissions reductions meet the 2020 target. Alternatively, ARB could revoke the informal guidance on resource shuffling, implement new regulations that either restrict resource shuffling or price any leakage from cross-border electricity transactions, and adjust the cap to reflect the existing leakage observed to date.

Both solutions require ARB to acknowledge the impacts that have already happened and will continue to occur if left unchecked. Until that time, the credibility of the state's carbon market will remain in question.

Respectfully submitted,

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My affiliation is for identification purposes only;
I am writing only in my individual capacity.

30 California Air Resources Board, 2010 Cap and Trade Regulation FED, supra note 26 at 378 (discussing leakage in the context of a CEQA evaluation of an alternative policy design that would employ border adjustments to goods and services imported to California).

Appendix — Calculating Observed Leakage

Calculating leakage from resource shuffling transactions requires information about the expected future production of both divested and replacement resources. If the precise pairwise replacement resource cannot be identified at the time of divestment, the leakage impacts can be bounded by the use of natural gas and zero-carbon replacement power benchmarks. Leakage will be highest if the replacement power is zero-carbon, and lower if natural gas is used; whatever mixture of replacement power supplies is used will fall in between these two benchmarks.

The first step in calculating leakage is to determine the period during which leakage will occur. This period begins when a covered entity divests from a high-emitting resource and ends at the earlier of (1) the end of the last carbon market compliance period in December 2020, or (2) when the high-emitting, divested resource retires. Leakage periods for the three transactions are shown in Table 2.

Next, the annual leakage rate can be estimated using historical and forecasted electricity production delivered to California purchasers, along with facility-level emissions rates. Here, a representative production level is calculated from recent and projected production as reported by utility and power purchasers to the California Energy Commission.[31] The facility-level emissions rates are based on heat rates from the Velocity Suite Database (provided by the California Energy Commission) and fuel emission rates from the Energy Information Administration.[32] Table 3 contains the representative electricity production and emissions rate data for each facility based on this information.

Representative annual emissions for the three facilities are shown in Table 4. These numbers reflect the representative electricity production scenario for each facility, with emissions rates calculated for three fuel scenarios. The coal scenario uses the facility-level emissions rate from Table 3. The natural gas scenario uses ARB's default emissions factor

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[31] California Energy Commission, Form S-2 for 2011 and 2013, *available at* http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2011/ and http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2013/.

Note: Data from 2009 and 2010 come from 2011 Form S-2 filings. Data from 2011 and 2012 come from 2013 Form S-2 filings. Data from 2014-2015 are utility-reported forecasts in 2013 Form S-2 filings.

Note: SCE did not report 2013 numbers for Four Corners in the Form S-2 filings; the reported forecasts for 2014 and 2015 were zero due to planned divestment.

Note: DWR divested from Reid Gardner in July 2013. 2013 data were excluded to avoid intra-annual variations in energy consumption due to the department's use of the power for the state water project.

[32] Ventyx, Velocity Suite Database, *available at* http://www.ventyx.com/en/enterprise/business-operations/business-products/velocity-suite; United State Energy Information Administration, Voluntary Reporting of Greenhouse Gases Program, Fuel Carbon Dioxide Emissions Coefficients, *available at* http://www.eia.doe.gov/oiaf/1605/coefficients.html.

for unspecified power (0.428 tCO_2 per MWh),[33] which is representative of baseload natural gas power plants. The zero carbon scenario assumes zero emissions, which is representative of nuclear or renewable power plants.

Finally, Table 5 reports the plant-level leakage estimates. Leakage estimates are determined by multiplying the number of years of leakage by the annual leakage rate. In the case of natural gas replacement power, the annual leakage rate is the difference between the coal and natural gas scenarios in Table 4. In the case of zero-carbon replacement power, the annual leakage rate is the difference between the coal and zero-carbon scenarios in Table 4 (*i.e.*, the same as the coal scenario). If production at the divested high-emitting facility increases after divestment, actual leakage will be higher than is reported here. If production falls, actual leakage will be lower. Similarly, if the facility retires earlier than specified in Table 2, actual leakage will be lower.

Table 2: Leakage Periods for the Three Observed Transactions

Facility	Divestment	Retirement?	Leakage Period
Navajo Generating Station	December 2015	Not planned.	5 years
Four Corners Units 4 & 5	December 2013	Not planned.	7 years
Reid Gardner Unit 4	July 2013	December 2017	4.5 years

Table 3: Representative Facility-Level Data

Facility	Period	**Average Output** (GWh per year)	**Emissions Rate** (tCO_2 per MWh)
Navajo Generating Station	2009 – 2015	3,906	1.02
Four Corners Units 4 & 5	2009 – 2012	5,143	0.97
Reid Gardner Unit 4	2009 – 2012	872	1.08

33 Cal. Code Regs. tit. 17, § 95111(b).

Table 4: Representative Annual Emissions

Facility	Annual Emissions (million tons CO_2 per year)		
	Coal	Natural Gas	Zero-Carbon
Navajo Generating Station	3.97	1.67	0
Four Corners Units 4 & 5	4.97	2.20	0
Reid Gardner Unit 4	0.94	0.37	0

Table 5: Leakage from Observed Transactions

Facility	Leakage (Million tons CO_2 through 2020)	
	Natural Gas Replacement	Zero Carbon Replacement
Navajo Generating Station	11.5	19.9
Four Corners Units 4 & 5	19.4	34.8
Reid Gardner Unit 4	2.6	4.2
Total	33.5	58.9

Attachments

- Borenstein et al., EMAC Market Report (June 2013)
- Bushnell et al., Energy Institute @ Haas Working Paper #236 (January 2013)

DRAFT – Comments Welcome

Forecasting Supply and Demand Balance in California's Greenhouse Gas Cap and Trade Market

by
**Severin Borenstein, James Bushnell,
Frank A. Wolak and Matthew Zaragoza-Watkins[1]**

June 12, 2013

I. INTRODUCTION

Among the many challenges in combatting climate change is the enormous uncertainty inherent in dealing with a problem of global scale with causes and impacts that are felt over the span of centuries. Independent of the impressive strides made in understanding the implications of atmospheric greenhouse gas (GHG) levels on the world's climate, great challenges remain in analyzing the economic costs of those changes, the costs of reducing emissions below dangerous levels, and even, fundamentally, the expected level of future emissions under a range of potential policies.

The cost of implementing GHG mitigation policies is a question of great interest and relevance at both the international and regional level. Of course, the specifics of the policy and the environment in which it is applied critically drive this question. Economists often frame the policy question in terms of the merits of a tax relative to those of an emissions cap, or one of "prices vs. quantities." In general, the benefits of a tax is that it can provide more predictable costs, while a cap can in theory provide more certainty as to the level of emissions.

In practice the reality of the implications of policy choice is more complex. Caps on emissions, where they have been applied, have been imposed only regionally, and only on a subset of the industries and sources producing GHG. Given that all these regions and industries interact with each-other in a global economy, the emissions certainty provided by capping only some industries in some countries is therefore greatly diluted. The certainty provided by a tax is limited by the extent to which policy makers can commit not to change the tax if it fails to produce the expected abatement. Last, the choice is frequently not one that requires full commitment to either a cap or tax alone. In many contexts, the two policies can be combined to reduce the risks presented by a commitment to either a cap or tax alone.

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[1] This research was performed under a contract with the California Air Resources Board. Bailey, Borenstein, Bushnell, and Wolak are members of the Emissions Market Assessment Committee and the Market Simulation Group that advise CARB. Zaragoza-Watkins works with the EMAC and the MSG as a researcher. The opinions in this paper do not represent those of the California Air Resources Board or any of its employees. Emails addresses: Bailey: ebailey@haas.berkeley.edu; Borenstein: borenste@haas.berkeley.edu; Bushnell: jbbushnell@ucdavis.edu; Wolak: wolak@zia.stanford.edu; Zaragoza-Watkins: mdzwatkins@berkeley.edu .

California's Cap and Trade market in greenhouse gases was recently launched, with the first allowance auction taking place on November 14, 2012 and compliance obligations commencing on January 1, 2013. The market is scheduled to last for eight years, through the end of 2020. This market is a modified cap and trade system with a limited price-collar mechanism. There is both an escalating auction reserve price, managed through adjustments to the supply of allowances to the periodic auctions, and a *price-containment reserve* designed to have a restraining effect on prices on the high end.

While the general details of the operations of both the auction reserve price and containment reserve are outlined in the regulations developed by the California Air Resources Board (ARB),[2] there remains some uncertainty over the exact manner in which the containment reserve mechanism would be applied and the degree to which it can mitigate uncertainty over prices.[3] A key question relating to this issue is the extent to which either the auction reserve price or containment reserve price are likely to be relevant, that is, the probabilities that market prices may be near the auction reserve price or the containment price.

In this paper we develop estimates of the range of allowance prices and the probabilities that one of the price containment mechanisms may be binding. A key factor driving these probabilities is the supply of abatement in California, which is likely to be highly non-linear. We find that a large supply of abatement will be available at prices below or very close to the auction reserve price, and as we argue below relatively little additional abatement will be available until price rises high enough to trigger sales from the price containment reserve. This abatement supply function, in turn, implies a bi-modal distribution of prices most of the probability mass at low or high price outcomes. The other critical factor is the relatively high degree of uncertainty surrounding expected "business as usual" (BAU) emissions that would result if there were no GHG reduction policies. In this paper we develop estimates of the range of BAU emissions utilizing forecasting techniques adapted from time-series econometrics, which we apply to emissions and economic data from 1990-2012 in order to forecast future emissions and the uncertainty of emissions.

Our empirical assessment of the potential demand for emissions allowances and supply of abatement and offsets suggests that the most likely outcome in the market will be a price very close to the auction reserve level.[4] In what we view as the most plausible scenario, we find an 80% probability of such an outcome. In all of the scenarios we examine, however, we find a very low probability that the price will be in an intermediate range, substantially above the auction reserve level, but below the containment reserve prices. Thus, most of the remaining probability weight is on outcomes in which some or all of the allowances in the price containment reserve are needed. Throughout this analysis, we assume that no market participant is able to exert market power or manipulate the market for emission allowances. That is, we assume at this point

[2] The regulations are available at: http://www.arb.ca.gov/cc/capandtrade/september_2012_regulation.pdf.

[3] See the ARB Board resolution dated October 18, 2012 at http://www.arb.ca.gov/cc/capandtrade/final-resolution-october-2012.pdf and an issue analysis from the Emissions Market Assessment Committee dated September 20, 2012 at http://www.arb.ca.gov/cc/capandtrade/emissionsmarketassessment/pricecontainment.pdf.

[4] Througout this paper we will refer to an "allowance market." The trading of allowances and there derivatives will be arranged through several competing and coexisting platforms – including quarterly auction of allowances by the State. We assume that prices between these markets will be arbitraged so that all trading platforms will reflect prices based upon the overall aggregate supply and demand of allowances and abatement.

that the emissions market is completely competitive, that no market participant is able unilaterally, or collusively, to profitably change their supply or demand in order to alter the market price. In ongoing work, we are analyzing the potential for market power and market manipulation given the characteristics of supply and demand in the market.

The remainder of this analysis proceeds as follows. Section II gives an overview of the possible outcomes in the market for California emissions permits given the characteristics of supply and demand. Section III describes how we estimated BAU GHG emissions forecasts (and associated standard errors) for 2013-2020. Section IV assesses the supply of abatement related to complementary policies. Section V analyzes the supply of abatement related to the potential "reshuffling" of electricity purchases among buyers and sellers, also known as "resource shuffling." Section VI assesses the supply of abatement related to offsets. Section VII assesses the supply of abatement related to price responsiveness. Section VIII compares BAU GHG emissions forecasts to the likely supply of relatively low-cost abatement and estimates the probability that the price containment reserve will be exhausted under various scenarios. We conclude in Section IX.

II. CALIFORNIA GHG CAP AND TRADE SUPPLY/DEMAND ECONOMICS

We focus on estimating the potential range and uncertainty of allowance prices over the 8-year span of the market. Fundamentally, the range of potential allowance prices is driven by the potential supply and demand for abatement of emissions. The underlying source of demand for allowances will be emissions of GHGs from the covered sources. The need for abatement will be determined by the difference between GHGs emissions under an uncapped (zero-price) BAU and the number of allowances issued under the program. Banking and borrowing of allowances is permitted among the years of each compliance period and banking is permitted between compliance periods, so the eight years of the market should be economically integrated. As a result, we examine the total supply and demand balance over the entire 8-years of the program (2013-2020). Because there is a large degree of uncertainty around the level of BAU emissions, we pay particular attention to establishing confidence intervals for these levels.

The number of allowances available in the California GHG cap and trade program derives from the allowance cap, a portion of which is allocated to a price containment reserve.[5] Of the 2,508.6 MMT of allowances in the program over the 8-year period, 121.8 MMT of allowances are assigned to the price containment reserve to be made available in equal proportions at allowance prices of $40, $45, and $50 in 2013. These price levels then increase each year at 5% plus the rate of inflation in the prior year.

The supply of abatement is multi-faceted and features several elements that are either unique, or present in a more extreme form, in California. These elements combine to create an extremely non-linear abatement supply curve, which we will demonstrate implies the potential for a wide-range of price outcomes. Abatement of capped emissions will flow through two mechanisms: a direct effect in which firms or consumers reduce emissions in response to a level

[5] The price containment reserve is funded as follows: 1% of the allowance cap in each of 2013 and 2014, 4% of the allowance cap in each of 2015, 2016, and 2017, and 7% of the allowance cap in each of 2018, 2019, and 2020.

of allowance prices, and an independent effect in which emissions are reduced as a consequence of policies outside of the setting of the cap. These outside policies are often called "complimentary policies" in California.

The supply of relatively price-independent abatement comes from (a) programs that abate GHGs independent of the price in the market (often called "complementary policies"), (b) activities that reduce measured GHGs due to the process of accounting for electricity imports ("reshuffling" and "relabeling"[6]), and (c) offsets (which might be considered a form of lessening demand rather than increasing supply, but the analysis would be unchanged). While incentives for reshuffling and offsets are affected by the price of allowances, previous analyses suggest that the impact of allowance prices is likely to be small over the range between the auction reserve price and the prices at which allowances are made available from the price containment reserve.

In its revised scoping plan of 2010, ARB's preferred model projects that 63% of emissions abatement would arise from complimentary policies rather than responses to the cap (four additional sensitivity models project between 30% and 63% of emissions abatement would arise from complementary policies).[7] Translating these sources of abatement into a traditional supply curve format produces a large quantity of abatement that would arise *at any permit price*. In other words, even at the auction reserve price, there is a very large quantity of abatement – with an accompanying range of uncertainty – provided. It is important to recognize that these reductions are not costless, indeed many may impose costs above the allowance price. Rather, these reductions, and the accompanying costs, will occur independent of the level of the permit price. Therefore, while these policies provide reductions, and contribute to the goal of keeping emissions under the cap, they do not provide the price-responsive abatement that can help mitigate volatility in allowance prices.

As described below, the supply of price-responsive mitigation is limited by the allocation policies that have been implemented under AB 32. The large amount of allowances allocated using an approach known as output-based updating is expected to limit the impact of allowance prices on production levels and consumer prices for many industries.[8] Most of the remaining reductions in response to allowance prices would therefore come from consumer responses to changes in energy products, namely transportation fuels (gasoline), natural gas, and, possibly, electricity consumption. Compared to the aggregate level of reductions needed and expected under AB 32, the reductions from these energy price effects are relatively small.[9]

The combination of large amounts of "zero-price" abatement, and relatively modest price-responsive abatement creates a hockey stick shaped, abatement-supply curve (See Figure

[6] Relabeling describes the practice of reselling out-of-state power that comes from a high-emissions source such that the buyer can then import the power into California at the administratively determined default emissions rate.
[7] See http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf at page 38 (Table 10).
[8] Output-based updating of allocations serves to dilute the incidence of the allowance price on firms and consumers (see Meredith Fowlie, "Updating the Allocation of Greenhouse Gas Emissions Permits in a Federal Cap-and-Trade Program," in Don Fullerton and Catherine Wolfram, ed. The Design and Implementation of U.S. Climate Policy, University of Chicago Press. 2012.. If applied to a large enough set of industries or fraction of the allowances, the effect can be to inflate permit prices as higher prices are necessary to offset the diluted incentive to pass the carbon price through to consumers. (See Bushnell, James and Yihsu Chen. "Regulation, Alllocation, and Leakage in Cap and Trade Markets for CO2." *Resources and Energy Economics. 34(4), 2012.*
[9] Offsets and reshuffling/relabeling may also be sensitive to allowance prices, but are considered separately.

1). Analysis undertaken by ARB indicates that the marginal abatement cost curve rises sharply after the relatively low-cost abatement options are exhausted. ARB states in its updated Scoping Plan dated March 2010 that "…GHG emissions in the model show limited responsiveness to allowances prices…This lack of responsiveness results from the limited reduction opportunities that have been assumed to be available in the model."[10] As a result of the sharp increase in marginal abatement costs, the marginal abatement cost curve is expected to be shaped more like a hockey stick than the canonical gently upward sloping curve that is often seen in economic textbooks when illustrating a marginal abatement cost curve.

One implication of this is that allowance prices are more likely to be either at or near the level of the auction reserve price or at levels set by the containment reserve policy than they are to fall at some intermediate level. When one considers an uncertain range of BAU emissions, even if strongly centered on the expected level, the probabilities of prices falling at either the ceiling or auction reserve price constitutes a large fraction of the overall distribution of potential emissions outcomes.

This intuition is illustrated in Figure 2, which superimposes a hypothetical symmetric distribution of the amount of abatement needed (BAU emissions less the cap) onto the same horizontal axis as our supply curve. Note from Figure 2 that the range of abatement quantity that falls between the auction reserve price ($10.50/a ton in this illustration) and the price-containment "ceiling" ($50/ton in this illustration), which is the area with no pattern, is relatively small.

The implications of California's abatement supply is therefore that the vast majority of probability for a given price outcome falls either at the auction reserve price or in the range in which the price containment policy is likely to be triggered. Rather than the familiar bell-shaped distribution of expected prices, it is more appropriate to think of the probabilities as distributed according to the dashed line of Figure 3, which has the same mean as the solid line, but this mean is generated by a high probability of a "low" (auction reserve) price balanced by a somewhat lower probability of a "high" (price containment reserve) price.

III. ESTIMATES OF BUSINESS AS USUAL EMISSIONS

Perhaps the largest factor driving the supply/demand balance in the GHG market will be the level of emissions that would take place under BAU. There is, however, considerable uncertainty about BAU emissions over the period 2013 to 2020. To derive estimates of the expected future time path of GHG emissions and the associated uncertainty associated with this forecast, we estimate a Vector Autoregression (VAR) model for the 3 major components of state-level GHG emissions and the key statewide factors that impact the level and growth of GHG emissions.[11] Due to the short time period for which the necessary disaggregated GHG

[10] Available at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf. See also, the ARB analysis contained in Appendix F: Compliance Pathways Analysis available at: http://www.arb.ca.gov/regact/2010/capandtrade10/capv3appf.pdf.

[11] Vector Autoregressions are the econometric methodology of choice among analysts to construct short to medium-term (from 1 to 10 time periods into the future) forecasts of macroeconomic variables and for this reason are ideally suited to our present task.

emissions data have been collected, the model estimation is based on annual data from 1990 to 2010. Because data is available for 2011 and 2012 on real Gross State Product (GSP) in California, we condition on these values in forecasting the expected future time path of state-level GHG emissions and the uncertainty in the future time path.

Several features of our VAR model are chosen to match the time series relationships between the nine variables implied by economic theory and existing state policies to limit GHG emissions. We allow for the fact that all nine variables exhibit net positive or negative growth over our sample period and model them as stochastic processes that are 2^{nd}-order stationary in growth rates rather than 2^{nd}-order stationary in levels. We also impose restrictions on the parameters of the VAR model implied by the co-integrating relationships between these nine variables that are supported by the results of preliminary hypothesis tests As shown by Engle and Yoo (1987) imposing the parameter restrictions implied by co-integrating relationships between variables in VAR model improves the forecasting accuracy of the estimated model.[12] Finally, we chose the variables that enter our 9-dimensional VAR to allow us to restrict the GHG emissions intensity of major fossil fuel-consuming activities in California in constructing forecasts of future GHG emissions.

Model

Let $X_t = (X_{1t}, X_{2t}, \ldots, X_{9t})'$ denote the vector composed of the nine annual magnitudes included in the VAR for year t, t=1990, 1991,…,2010. The elements of X_t are:

X_{1t} = [(Industrial GHG Emissions)/(Natural Gas and Other GHG Emissions)]

X_{2t} = [(Industrial GHG Emissions+Natural Gas and Other GHG Emissions)/Real State GSP]

X_{3t} = [Total Vehicle Miles Traveled]

X_{4t} = [Total In-state Electricity Production in Terawatt-hours]

X_{5t} = [Real State GSP]

X_{6t} = [Real Oil Price in dollars per barrel]

X_{7t} = [Transportation Sector GHG Emissions/Total Vehicle Miles Traveled]

X_{8t} = [In-state Electricity Sector GHG Emissions/Instate Electricity Production]

X_{9t} = [In-state Electricity Consumption in Terawatt-hours]

All real dollar magnitudes are expressed in 2005 dollars. All GHG emissions are in Tons of CO_2-equivalents. GSP captures the empirical regularity--observed both over time and across jurisdictions--that a higher level of economic activity leads to greater energy consumption and GHG emissions. We include factors that lead to the consumption of fossil fuels such as in-state electricity production, total vehicle miles traveled, and in-state electricity production. We model the GHG emissions intensity of in-state electricity production, total vehicle miles traveled and

[12] Engle, Robert F., and Yoo, Byung Sam (1987) "Forecasting andTesting in Co-Integrated Systems," *Journal of Econometrics*, 35, 143-159.

real state GSP because we expect that state policies to limit GHG emissions are likely to impact these intensities, whereas the other variables are likely to continue to grow as the California economy grows. We do not include the GHG emissions content of electricity imports because this is largely an administratively determined number, because as a matter of physics, it is impossible to measure the GHG emissions content of electricity imports. All that can be measured is the aggregate GHG emissions outside of California and total electricity produced outside of California.

Define $Y_{it} = \ln(X_{it})$ for i=1,2,…,9 and $Y_t = (Y_{1t}, Y_{2t}, \ldots, Y_{9,t})'$. In terms of this notation a first-order autoregression or VAR that is stationary in first-differences can be written as

$$\Theta(L)Y_t = \varepsilon_t \qquad (3.1)$$

where L is the lag operator which implies, $L^kY_t = -Y_{t-k}$, I is a (9x9) identity matrix, $\Theta(L)$ is (9x9) matrix function in the lag operator equal to $(I - \Theta_1 L - \Theta_2 L)$ where each Θ_i (i=1,2) is a (9x9) matrix of constants, and ε_t is a (9x1) white noise sequence with (9x1) mean vector μ and (9x9) covariance matrix Ω. Recall that white noise series are uncorrelated over time. In terms of the lag operator notation $(1-L) = \Delta$, so that $\Delta Y_t = Y_t - Y_{t-1}$.

Although model (3.1) allows each element of Y_t to be non-stationary, reflecting the fact that each element exhibits net positive or negative growth over the sample period, economic theory suggest that certain linear combinations of the elements of Y_t are likely to be 2^{nd}-order stationary in levels. Times series processes that are 2^{nd}-order stationary in first-differences (i.e., ΔY_t is 2^{nd}-order stationary) that have stationary linear combinations of their elements are said to be co-integrated. That is because stochastic processes that are stationary in first-differences are also called integrated process with the order of integration equation equal to 1. The number of stationary linear combinations of the elements of Y_t is called the co-integrating rank of the VAR that is 2^{nd}-order stationary in first-differences. The co-integrating rank is also equal to the rank of the matrix $(I - \Theta_1 - \Theta_2)$.

The existence of co-integrating relationships between elements of Y_t imposes restrictions on the elements of Θ_1 and Θ_2. Suppose that the rank of the matrix $(I - \Theta_1 - \Theta_2)$ is equal to r ($0 < r < 9$), the number of stationary linear combinations of the elements of Y_t. This implies that the following error correction representation exists for Y_t:

$$(I - \Lambda L)\Delta Y_t = -\gamma Z_{t-1} + \varepsilon_t \qquad (3.2)$$

where $Z_t = \alpha' Y_t$ is a (r x 1) vector of 2^{nd}-order stationary random variables and γ is a (9 x r) rank r matrix of parameters and α is a (9 x r) rank r matrix of co-integrating vectors, Λ is a (9x9) matrix of parameters and $(I - \Theta_1 - \Theta_2) = \gamma\alpha'$.

Johansen (1988) devised a test for the co-integrating rank of a VAR that is 2^{nd}-order stationary in first-differences.[13] Applying this test to Y_t finds that the null hypothesis that r, the rank of $(I - \Theta_1 - \Theta_2)$, is 3 can be rejected at a 0.05 level, yet the null hypothesis that r, the rank of $(I - \Theta_1 - \Theta_2)$ is 4, cannot be rejected at a 0.05 level. This hypothesis testing result is consistent with the existence of 4 stationary linear combinations of the elements Y_t. We impose these co-

[13] Johansen, S. (1988) "Statistical Analysis of Cointegration Vectors," Journal of Economic Dynamics and Control, 12, 231-254.

integrating restrictions on the parameters of VAR model (3.1) that we estimate to forecast future GHG emissions.

Our estimation procedure yields consistent, asymptotically normal estimates of μ, Ω, and Θ_1 and Θ_2 with the co-integrating restrictions imposed. Using these parameter estimates we can then compute an estimate of the joint distribution of $(X_{2013}, X_{2013,...,}X_{2020})'$ conditional on the values of (X_{2009}, X_{2010}) that takes into account both our uncertainty in the values of μ, Ω , Θ_1, Θ_2 because estimation error and uncertainty due to the fact that $(X_{2013}, X_{2013,...,}X_{2020})'$ depends on future realizations of ε_t for t=2011, 2012, ..., 2020. Because we have values for Real State GSP for 2011 and 2012, we compute our estimate of the distribution of $(X_{2013}, X_{2013,...,}X_{2020})'$ conditional on these values as well as the observed values of (X_{2009}, X_{2010}).

We employ a two-stage smoothed bootstrap approach to compute an estimate of this distribution. The first step computes an estimate of the joint distribution of the elements of μ, Ω, and Θ_1 and Θ_2 sampling from the smoothed empirical distribution of the (9x1) vector of residuals from the estimated Vector Error Correction Model (VECM). Let $\hat{\mu}$, $\hat{\Omega}$, $\hat{\Theta}_1$, and $\hat{\Theta}_2$equal the estimates of the elements of the VECM. Compute

$$Y_t - \hat{\Theta}_1 Y_{t-1} - \hat{\Theta}_2 Y_{t-2} = \hat{\varepsilon}_t \tag{3.3}$$

for t=1990 to 2010. Construct the smoothed kernel density estimate of the $\hat{\varepsilon}_t$ as

$$\hat{f}(t) = \frac{1}{Th^9}\sum_{t=1}^{T} K\{\frac{1}{h}(t - \hat{\varepsilon}_t)\} \tag{3.4}$$

where T is the number of observations, h is a user-selected smoothing parameter, and K(t) is a multivariate kernel function that everywhere positive and integrates to one. We use the multivariate normal kernel

$$K(x) = \frac{1}{(2\pi)^{9/2}}\exp(-\frac{1}{2}x'x) \text{ where } x \in \mathbb{R}^9.$$

and h=0.5, and we found that are results were insensitive to the value chosen for h, as long as it was less than 1.

We then draw T=19 values from the (3.4) and use the parameter estimates and these draws to compute re-sampled values of Y_t for t=1,2,…,T = 19. Let $(\hat{\varepsilon}_1^m, \hat{\varepsilon}_2^m,..., \hat{\varepsilon}_{19}^m)'$denote the m^{th} draw of the 19 values of $\hat{\varepsilon}_t$ from $\hat{f}(t)$. We compute the 19 resampled values of Y_t by applying the following equation starting with the values of Y_t in 2000 and 2001.

$$Y_t^m = \hat{\Theta}_1 Y_{t-1}^m + Y_{t-2}^m \hat{\Theta}_2 + \hat{\varepsilon}_t^m \tag{3.5}$$

We then estimate the values of μ, Ω , Θ_1, Θ_2 using the Y_t^m. Call the resulting estimates $\hat{\mu}^m$, $\hat{\Omega}^m$, $\hat{\Theta}_1^m$, and $\hat{\Theta}_2^m$. Conditional on these values of we then draw ten values from $\hat{f}(t)$. Call the b^{th} sample of these values $(\hat{\varepsilon}_{T+1}^{mb}, \hat{\varepsilon}_{T+2}^{mb},..., \hat{\varepsilon}_{T+10}^{mb})'$. Using these draws and $\hat{\mu}^m$, $\hat{\Omega}^m$, $\hat{\Theta}_1^m$, and $\hat{\Theta}_2^m$ compute future values Y_{T+k} given Y_T and $Y_{T-1.}$

$$Y_{T+k|T,T-1}^{bm} = \hat{\Theta}_1^m\, Y_{T+k-1|T,T-1}^{bm} + \hat{\Theta}_1^m\, Y_{T+k-1|T,T-1}^{bm} + \hat{\varepsilon}_{T+k}^{mb} \text{ for k=1,2,…,10.} \tag{3.6}$$

This is yields one realization of the future sample path of Y_t for t=2011, 2012,…, 2020. The elements of Y_t can then be transformed to X_t by applying the transformation $X_{it} = \exp(Y_{it})$) to each element of Y_t to yield a realization of the future time path of X_t. The elements of X_t are then transformed produce a realization of the future time path of GHG emissions by each covered sector. We repeat the first step of the process m = 1 to M=500 times and conditional on each value of $\hat{\mu}^m$, $\hat{\Omega}^m$, $\hat{\Theta}_1^m$, and $\hat{\Theta}_2^m$ we repeat the second simulation of future values of Y_t for t=2010 to 2020, b=1 to B=500 time to produce 250,000 realizations from the simulated distribution of $(X_{2010}, X_{2011,\ldots,}X_{2020})'$. By increasing M and B, we can also compute a simulated distribution $(X_{2013}, X_{2014,\ldots,}X_{2020})'$ that conditions on the values of real state GSP in 2011 and 2012, by simply restricting for consideration sample paths with $(X_{2013}, X_{2014,\ldots,}X_{2020})$ where the realized values of real state GSP in 2011 and 2012 lie in a small intervals around the values in 2011 and 2012.

Because of our concern that state policies to reduce GHG emissions would likely limit the GHG emissions intensity of total vehicle miles traveled, in-state electricity production and real state GSP, we impose upper bounds on these three GHG emissions intensity measures. This was accomplished by truncating realizations of the value of these intensity figures in computing the future time path of GHG emissions. For example, if a realization of a GHG emissions intensity in any realization of the two-step process of computing the joint distribution of $(X_{2013}, X_{2013,\ldots,}X_{2020})'$ exceeds our upper bound, we re-set the value of that intensity for that year to our upper bound to compute GHG emissions for that sector for that year. For example, if the realization for certain values m and b of (GHG Emissions from the Transportation)/(Total Vehicle Miles Traveled) exceeds the upper bound for that year, the realized value for GHG Emissions from Transportation would be set equal to that upper bounds times the realized value of Total Vehicle Miles Traveled. Similar procedures were followed using the other two intensity measures to compute future GHG emissions from those covered sectors.

Because California's cap and trade program phases in the entities under the cap over time, our approach separately forecasts emissions from Phase I entities (narrow scope) and Phase II entities (broad scope). Phase I, in effect during the first compliance period, 2013 and 2014, covers electricity generation and emissions from large industrial operations. Phase II, in effect for the second and third compliance periods, 2015-2017 and 2018-2020, expand the program to include combustion emissions from transportation fuels, and emissions from natural gas and other fuels combusted at residences and small commercial establishments.

We do not forecast GHG emissions from electricity imports into California, because, as noted earlier, these are an administratively determined numbers based on the declared sources of supply of electricity imports. An additional reason to exclude electricity imports from the estimation is that the administrative process for determining the GHG emissions content of imports is still a subject of debate in the development of the market rules for what constitutes or does not constitute resource shuffling. Instead, we forecast future GHG emissions from in-state sources using each of the approaches described above and then add back in the administratively determined figures for electricity imports.

Data

Annual emissions levels for each covered sector are taken from the 1990-2004 Greenhouse Gas Emissions Inventory and the 2000-2010 Greenhouse Gas Emissions Inventory (hereafter, Inventory).[14] The longest series of consistently measured emissions data and the basis for developing the 1990 statewide emissions level and 2020 emissions limit required by AB 32, ARB staff rely primarily on state, regional or national data sources, rather than individual facility-specific emissions. However, due to differences in accounting, the Inventory likely overstates emissions from industrial activity relative to those covered in the first compliance period of the cap and trade program. In particular, the Inventory methodology may attribute some emissions to the industrial sector – such as natural gas combustion from small industrial or commercial sources – that are not covered until the second compliance period. We investigate the impact of this difference by comparing the Inventory data to annual data collected under the Mandatory Reporting Regulation (MRR), the methodology used to calculate an entity's compliance obligation under cap and trade.[15] We did not find that either our expected time path or uncertainty in the time path were impacted by plausible adjustments in the values GHG emissions from each of the covered sectors during our sample period that were aimed at making these two data sources consistent.

Comparing 2008 to 2010 MRR and Inventory industrial emissions data shows annual differences of 8.98 to 12.48MMT with Inventory industrial emissions thirteen percent higher than MRR industrial emissions, on average. We address this difference by forecasting industrial capped source emissions in the first compliance period using the Inventory industrial emissions data series adjusted downward by thirteen percent. We use the unadjusted Inventory data as our measure of industrial capped source emissions covered in the second and third compliance periods. As our maintained assumption is that the first compliance period difference is due to differences in accounting, as opposed to classical measurement error, using the Inventory emissions estimates for the second and third compliance periods should not bias our emissions estimates upward.

Real California GSP – measured in millions of 2005 dollars – is collected from the Bureau of Economic Analysis (BEA).[16] Real oil price are compiled United States Energy Information Administration as the annual average West Texas Intermediate (WTI) price at Cushing, Oklahoma.[17] In-state electric generation and electricity consumption are collected from the California Energy Commission (CEC).[18] Statewide on-road and off-road VMT are taken from ARB's Mobile Source Emissions Inventory.[19]

Results

[14] California's GHG emissions inventory is available at: http://www.arb.ca.gov/cc/inventory/inventory.htm.

[15] Information on the ARB mandatory reporting regulation is available at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

[16] Gross Domestic Product by State is available at: http://www.bea.gov/regional/index.htm#data.

[17] The nominal annual average West Texas Intermediate crude oil price in dollar per barrel is available at http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

[18] In-state California generation and natural gas consumption are available from the CEC at http://energyalmanac.ca.gov/electricity/index.html and http://energyalmanac.ca.gov/naturalgas/index.html, respectively.

[19] ARB's mobile source emission inventory is available at: http://www.arb.ca.gov/emfac/.

To construct estimates of the cumulative total emissions covered by the program from 2013 to 2020 requires we combine forecasts of GHG emissions from Phase I facilities for 2013 and 2014 and GHG emissions from Phase II facilities for 2015 to 2020. The results are presented in Figure 4a (stationary in growth rates with GHG ratios to other factors bounded above at their median levels in the dataset), Figure 4b (stationary in growth rates with GHG ratios to other factors bounded above at the 75th percentile levels in the dataset) and Figure 4c (stationary in growth rates with GHG ratios to other factors bounded above at their maximum levels in the dataset). In all three Figures the solid line represents the estimated cumulative GHG emissions to that year and the dashed lines around it represent the 95% confidence interval. In all three Figures, the slope of the cumulative emissions increases after 2014 as a result of the expansion of covered entities.

IV. COMPLEMENTARY POLICIES

The ARB analysis identifies several categories of complementary policies, which, if they fully achieve expectations, would yield a savings of 87 MMT during the year 2020.[20] Of this total, 38 MMT were incorporated into ARB's BAU forecast of emissions in 2020. The reductions for the years prior to 2020 are unknown to us. For the purposes of this analysis, we assume these reductions come into effect linearly over time, ramping upward from zero in 2012 to 87 MMT in 2020.

With regard to the 38 MMT of reductions included in ARB's BAU, it is important to note that to the extent existing trends in activities such as renewable electricity development and energy efficiency are already reflected in historic data, the continuation of these trends will also be reflected in our BAU forecast due to the vector autoregression approach that would capture pre-existing trends. For example, the historic data demonstrate a declining ratio of energy consumption to GSP on average, and that trend is incorporated into the BAU forecasts through 2020. For this reason, in some instances, it may be double counting to subtract reductions from complementary measures that were already present during the early 2000s and have been ramped up through the last decade and are likely to continue to rise. In recognition of this, and the uncertain nature of future reductions, we offer a range of average annual emissions reductions for each of the complimentary policies. Our best estimates of emissions reductions from additional complementary measures not already reflected in our BAU estimates are summarized Table 1 and explained in more detail in the following subsections.

[20] Documentation for the 87 MMT emission reductions total – 38 MMT from Pavely I and 20% RPS and 49 MMT from all other Scoping Plan Measures – are available at:
http://www.arb.ca.gov/cc/scopingplan/sp_measures_implementation_timeline.pdf and
http://www.arb.ca.gov/cc/inventory/data/tables/reductions_from_scoping_plan_measures_2010-10-28.pdf.

Table 1: Potential Emissions Reductions from Complementary Policies

Complementary Measure	Average Annual Reductions (2013-2020, above prior trend)	Years Under Cap	Total Aggregate Reductions Under Cap
20% and 33% RPS	7.8 – 12.4 MMT	2013 – 2020	62.4 – 98.8 MMT
Auto Standards	9.3 – 16.2 MMT	2015 – 2020	74.2 – 129.8 MMT
LCFS	0 – 10.3 MMT	2015 – 2020	0 – 61.9 MMT
Energy Efficiency	0 – 3.4 MMT	2013 – 2020	0 – 27 MMT
Other transport	0 – 1.5 MMT	2015 – 2020	0 – 12.4 MMT

a. Renewable Portfolio Standard

In 2010, renewable supply was about 14% of consumed electricity, reflecting an upward trend from about 10% in the mid-2000s. We assume a range of combined compliance with the 20% and 33% RPS to yield renewable energy in a range from 26% to 33% of total electricity consumption by 2020. This is assumed to ramp up at a linear rate from 14% in 2010 to the end target in 2020. Given 2010 Emissions Inventory overall electricity sector emissions of 92.2 MMT, we assume each additional percentage point of renewable energy saves on average about 1 MMT/year.

We assumed an increase from 17.8% in 2012 to 33% in 2020 on the high end of the estimate. This produces an annual average value of 26.4% or an increase of 12.4% (translating to a decrease of 12.4 MMT/year) from 2010 levels.

Following a similar methodology for the low-end estimate of 26% in 2020 produces an annual average reduction of 7.8 MMT/year. Total 8-year reductions are calculated by multiplying these annual average values by 8. The resulting range is therefore **62.4-98.8 MMT**.

b. Fuel Economy and Advanced Auto Standards

ARB staff estimates annual impact of 29.9 MMT from the combination California's "Pavley" fuel economy standards and advanced auto standards. Our understanding is that the latter standard has not yet been adopted. We therefore consider achieving this reduction to be less certain. We also adjust the impact downward to account for the interaction between the auto standards and the Low Carbon Fuel Standard (LCFS), which estimates an increase of non-petroleum fuels (most not under the cap) from 10 to 18% between 2010 and 2020. While we consider this last estimate aggressive, we adjust the auto impact downward to account for the fact that more of the fuel *not* consumed would not be otherwise covered under the cap. We assume full compliance with both standards to be the upper bound on savings, and assume a lower bound in which these standards are instead replaced by Federal CAFE standards. The resulting range of reductions is assumed to be 16 to 28 MMT in 2020 -- and ramping up linearly to these levels from 2012 levels -- which translates to a savings from 2015 to 2020 (fuels not being under the cap in earlier years) of **74.2 – 129.8 MMT**.

c. Low Carbon Fuel Standard

The LCFS would implement carbon reductions in two ways: increasing the percentage of low-carbon (non-petroleum) fuels and reducing the carbon content of the mix of non-petroleum fuels already consumed. Since all biofuels will be treated as zero carbon under the cap and trade program, only the former reductions would create savings under the accounting of the cap. Our understanding of ARB assumptions is that 15 MMT of reductions assumed to be achieved in 2020 stems from an increase of non-petroleum fuel mix from 10% to 18%. We consider the 18% to be an upper bound of the achievable range. Given the current uncertainty surrounding the ethanol blend-wall the willingness of stations to carry higher percentage mixes, we consider the assumed 10% mix to be a lower-bound. From the fuels consumption implied in our baseline, the Pavely standards would reduce the consumption of total fuels and we adjusted the impact of the LCFS accordingly. Our range of LCFS savings *under the cap* is therefore **0 – 61.9 MMT**.

d. Energy Efficiency Measures

With California's longstanding commitment to energy efficiency, we believe that a strong pre-existing trend of efficiency improvements is already present in the time-series data we used to forecast the BAU emissions. We are therefore concerned that further reductions from BAU for energy efficiency improvements would double count those reductions. We assume that savings under the cap range from **0 – 27 MMT,** where the high-end estimate assumes a 2020 reduction (above trend) of 6 MMT/year.

e. Other Transport

Other Transport includes complementary measures associated with regional targets (SB 375, which calls for sustainable community planning), tire pressure program, heavy duty aerodynamics as well as medium and heavy duty hybridization. ARB attributes 4.5 MMT of emission reductions to these programs in 2020. We assume that savings under the cap for these four combined measures ramp up linearly, creating a potential range from **0 – 12.4 MMT**.

V. RESHUFFLING AND RELABELING

ARB has attempted to include all emissions from out-of-state generation of electricity delivered to and consumed in California under the cap and trade program's GHG accounting framework. However, due to the nature of the Western Interconnection, it is often impossible to identify the source of generation supplying imported electricity. Electricity importers therefore have an incentive to engage in a variety of practices that lower the reported GHG content of their imports, a class of behaviors broadly labeled reshuffling. While reshuffling would not yield aggregate emissions reductions in the Western Interconnection, it could be a major source of measured emissions reductions under the cap and trade program.

ARB projects annual BAU emissions from imported electricity of 53.5 MMT, during the period 2013-2020. Under one extreme, importers could reshuffle all imports to GHG free resources, creating cumulative emissions reductions of 428.3 MMT. ARB may limit reshuffling by targeting imports from utility-owned coal plants, which are expected to account for 92.2 MMT during the eight-year period. However, we do not treat 336.1 MMT (full reshuffling less utility-owned coal imports) as the upper bound on reshuffling, because utility divestiture of a coal resource may not be considered reshuffling, regardless of the coal resource's future generation profile. Recognizing that additional soft uncertainties such as contracting costs, institutional inertia, and preferences of owners to maintain property rights to GHG free sources may impede full reshuffling, we put an upper bound on reshuffling at 360 MMT.

For a lower bound we first consider the difference between ARB's BAU estimates and 2009-2011 MRR emissions data. As ARB's BAU estimate was made without consideration of reshuffling, this difference in emissions associated with imports is likely a reasonable approximation of the minimum amount of costless reshuffling immediately available to the electric sector. The 2009-2011 MRR emissions data show an average reduction of 7.6 MMT from imported electricity emissions relative to ARB's BAU. If persistent, this would result in 60.8 MMT of emissions reductions through 2020. Additionally, the utilities have a number of long-term coal contracts that they are eligible to terminate under SB 1368. Replacing those coal contracts with unspecified power (which is administratively assigned 0.428 MMT/MWh) or GHG-free resources would result in cumulative reductions of 38.2 MMT and 78.3 MMT, respectively. In consideration of similar soft uncertainties arising from market frictions we choose a lower bound for reshuffling of 120 MMT. The resulting range of reshuffling is therefore **120-360 MMT**.

VI. OFFSETS

The cap and trade program permits a covered entity to meet its compliance obligation with offset credits equal to eight percent of its annual and triennial compliance obligations. ARB has approved four categories of compliance offset projects that can be used to generate offsets – U.S. Forest and Urban Forest Project Resources Projects; Livestock Projects; Ozone Depleting Substances Projects; and Urban Forest Projects. Each individual offset program is subject to a rigorous verification, approval, and monitoring process. The California ARB has approved two offset project registries – American Carbon Registry[21] and the Climate Action Reserve[22] –to facilitate the listing, reporting, and verification of specific offset projects. The Climate Action Reserve reports there are approximately 11.5 million existing offsets that were generated under a voluntary early action offset program overseen by the Climate Action Reserve that are eligible for conversion to cap and trade program compliance offsets.[23]

Offsets are expected to be a relatively low-cost (though not free) means for a covered entity to meet a portion of its compliance obligation.[24] The number of offsets expected to be available in the cap and trade program is subject to a high degree of uncertainty and best guesses put the estimate substantially below the potential number of offsets that could be used (i.e., 8% of compliance obligations). One recent third-party study from September 2012 estimates the number of offsets available under all four protocols between 2013 and 2020 at 66 MMT, only

[21] See http://americancarbonregistry.org/carbon-accounting/california-compliance-offsets.
[22] See http://www.climateactionreserve.org/.
[23] Data collected from the "listed projects" tab at http://www.climateactionreserve.org/.
[24] http://www.arb.ca.gov/regact/2010/capandtrade10/capv3appf.pdf.

30% of the nearly 220 MMT of offsets that theoretically could be used to satisfy compliance obligations.[25] As a result of this anticipated shortfall, we understand ARB has considered adding two additional offset protocols – Rice Cultivation and Coal Mine CH4 Capture and Destruction. The addition of these two protocols is estimated to make an additional 64 MMT of offsets available (for an estimated total of 130 MMT) between 2013 and 2020.[26]

For the purposes of our analysis, we assume the cumulative number of offsets available between 2013 and 2020 range between **75 MMT and 139 MMT.**[27]

VII. PRICE-SENSITIVE ABATEMENT

As the price of allowances rises, in some areas the increased cost will change consumer and producer behavior. In order to assess the potential abatement supply in the cap and trade market, we consider such price-elastic supply in four areas on the consumer side: demand for gasoline, diesel, electricity and natural gas. We also consider electricity generation and industrial emissions. For each of these areas, we calculate the abatement that would occur with the price at the auction reserve price, at the price to access the first tier of the containment reserve, and at the price to access the third tier of the containment reserve.[28]

a. Demand for Fuels

The potential impact of the allowance price on consumption of gasoline and diesel is a function of short-run effects, such as driving less and switching among family cars, and longer-run effects, such as buying more fuel-efficient cars and living in areas that require less use of an auto. If, however, fuel-economy standards have pushed up the average fuel economy of vehicles above the level consumers would otherwise choose (given fuel prices), then raising fuel prices will have a smaller effect, because the fuel-economy regulation has already moved them into the automobile fuel economy they would have chosen in response to higher gas prices. For this reason, in jurisdictions with effective fuel-economy standards, such as California, the price-elasticity of demand for fuels is likely to be low. Short-run price elasticity estimates are generally -0.1 or smaller (in absolute value).[29] Long-run elasticities are generally between -0.3 and -0.5.[30] Furthermore, the fuel-economy standards would also reduce the magnitude of emissions reductions by lowering the baseline level of emissions before the price of allowances has an effect, which we account for in our analysis of complementary policies.

We recognize that improved fuel economy standards will phase in gradually during the cap and trade compliance periods. To balance these factors, we assume the baseline level of

[25] http://americancarbonregistry.org/acr-compliance-offset-supply-forecast-for-the-ca-cap-and-trade-program.
[26] http://americancarbonregistry.org/acr-compliance-offset-supply-forecast-for-the-ca-cap-and-trade-program.
[27] The analysis described in this document assumes a single eight-year compliance time horizon. As a result, the analysis does not address the fact that any shortfall of offsets in earlier compliance periods cannot be recaptured in later time periods and thus results in a permanent shortfall in offsets from the theoretical potential.
[28] Each of these price levels escalates over time in real terms, so we calculate the price-sensitive abatement for each year separately.
[29] See Hughes, Jonathan E., Christopher R. Knittel and Daniel Sperling, "Evidence of a Shift in the Short-Run Price Elasticity of Gasoline." *The Energy Journal*, 29(1), January 2008.
[30] See Dahl, Carol A., " Measuring global gasoline and diesel price and income elasticities" *Energy Policy*, 41(1), 2012, pp. 2-13.

emissions is unchanged, but that the price elasticity of demand will be -0.1. At the highest price in the price containment reserve in each year (which is $50 in 2013 going up to $70.36 in 2020), the result is a reduction of **13.4 MMT** over the life of the program from reduced use of gasoline and diesel. Assuming an elasticity of -0.2 about doubles the reduction to **26.7 MMT**. (Note the fuels will be under the cap only in 2015-2020, so we calculate reductions for only these six years.)

b. Demand for Electricity

The impact of a rising allowance price on emissions from electricity consumption depends primarily on the pass-through of allowance costs to retail prices of electricity. A best guess seems to be that there will be little or no pass-through of allowance prices to customers, because utilities will be receiving free allocations that will offset their allowance obligations. Although in theory it is possible that utilities could raise marginal price and use the revenue from the free allocations to lower a fixed charge, in practice this seems very unlikely. It is particularly unlikely because other factors, primarily increased renewables penetration, are likely to be pushing up costs and prices independent of the cap and trade program, though cheap natural gas may mitigate this impact somewhat. Taking an average statewide retail electricity price of $120/MWh, assuming that this increases by $20 due to exogenous (to cap and trade) factors and assuming a demand elasticity of -0.2 and a marginal CO_2e intensity of 0.428 MT/MWh, yields a reduction of **24.4 MMT** at the highest price in the price containment reserve over the life of the program. Both the elasticity and the CO_2e intensity figures are probably a bit on the high side, so a low-scenario figure would be **15 MMT**. Whichever figure is used, we include this in the price-inelastic abatement figure, because the reduction is likely to result from the impact of complementary renewables policies on retail rates and, thus, would be independent of the price of allowances.

c. Demand for Natural Gas

At this point, utilities are not scheduled to receive free allocation of allowances for their natural gas sales and the allowance cost is expected to be passed through to consumers. "Consumers" in this case include all emissions sources not covered in the industrial categories. Large industrial customers are in the program during the first compliance period. We assume a baseline emissions rate of 49.7 MMT/year for each of the six years that non-industrial customers are in the program. We assume an average retail price of $9/MMBTU across all nonindustrial types of natural gas customers (residential is a bit over $10, small commercial about $9, large commercial about $7) and 100% pass-through of the allowance cost to retail. It's difficult to know the elasticity of retail demand for natural gas. We take a low-end estimate of -0.2 and a high-end estimate of -0.4 over the 6-year time frame of natural gas in the program.[31] Based on these assumptions, at the highest price in the price containment reserve, the low scenario estimated abatement is **18.5 MMT** and the high scenario is **35.8 MMT**.

d. Abatement from Out-of-State Electricity Dispatch Changes

[31] Though some estimates of the price elasticity of gas and electricity demand are higher than those we use here, such estimates generally include substitution from gas to electricity and vice versa, which would have a much smaller net impact on emissions.

To the extent that some high-emissions out-of-state coal plants are not reshuffled or declared at the default rate, there is possible elasticity from higher allowance prices incenting reduced generation from such plants. We considered this, but the most recent reshuffling treatment from ARB suggests that incremental reshuffling from these plants will not be punished. If that is the case, then an operator would be better off reshuffling some of the power than actually reducing output from the plant. This suggests that some reshuffling may exhibit price elasticity. In any case, we consider that as part of the reshuffling and relabeling analysis.

e. Industrial Emissions

For the industries covered under output-based updating, there may still be some emissions reductions as the allowance price rises. This could happen in two ways. First, once a baseline ratio of allowances to output is established, these firms have an incentive to make process improvements that reduce GHG emissions for a given quantity of output. It is unclear how much of such improvement is likely to occur. At this point we have no information on this. Our current estimates assume this is zero, but further investigation of this factor is warranted. Second, because the output-based updating is not 100%, additional emissions that result from marginal output increases do impose some marginal cost on the firms. That impact is likely to be small, however, because the effective updating factors average between 75% and 90% over the program, which implies that the firm faces an effective permit price of 10% – 25% of the market price for emissions that are associated with changes in output. At this point, we have not incorporated estimates of this impact, but it seems likely to be quite small.

VIII. SUPPLY/DEMAND BALANCE UNDER ALTERNATIVE SCENARIOS

In order to compute the probabilities of different price outcomes in California's GHG market, we combine the BAU emissions forecasts generated from the models we estimated in Section III with scenarios for allowance, abatement and offset supply. We consider four mutually exclusive and exhaustive potential market clearing price ranges: (1) at or near the auction reserve price, without any access of the price containment reserve, and low-cost abatement and offset supply, (2) noticeably above the auction reserve price, without any access of the price containment reserve, with marginal supply coming primarily from price-elastic sources, (3) above the lowest price at which allowances would be available from the price containment reserve, but at or below the highest price of the price containment reserve, and (4) above the highest price of the price containment reserve.

We characterize price range (1) as "at or near" the auction reserve price, because the mechanism of the auction reserve price implies an uncertain economic price floor. The auction reserve price was set at $10 per tonne for 2012 and then rising at 5% per year plus inflation. Setting aside the uncertainty of inflation, if investors' real cost of capital differs from 5%, then the effective economic price floor will not be the auction reserve price. If, for instance, investors' real cost of capital were 3% per year for an investment such as this, then the effective price floor today would be the present discounted value of the price floor in the last auction in which allowances are sold.[32] Thus, in any one year the effective economic price floor may differ somewhat from the auction reserve price.

As of this writing, the ARB is expected to implement new policies to address the possibility of the price containment reserve being exhausted. We do not address how high the price might go in case (4), which would be difficult to do even in the absence of this policy uncertainty, but in any case will be greatly influenced by the ARB's policy decisions scheduled to occur in the next year. We simply report the estimated probability of reaching this case.

Our analysis is in terms of real 2012 dollars, so there is no need to adjust for inflation, but the price trigger levels for the price containment reserve will, under current policy, increase at 5% in real terms every year. Thus, while the containment reserve is made available at prices from \$40-\$50 in 2013, the range escalates to \$56.28-\$70.35 in 2020 (in 2013 dollars). As we show below, the containment reserve prices are only likely to occur if BAU GHGs grow faster than anticipated over many years, so the relevant containment reserve prices are those that will occur in the later years of market operations, when such growth would become evident. For that reason, we use the 2020 price containment trigger prices for our analysis.

We consider BAU GHG emissions forecasts under the three different estimation approaches described in Section III and presented in Figures 1, 2, and 3: assuming GHG emissions are (a) stationary in growth rate with GHG ratios to the other variables bounded above at their median level of the 1990-2012 sample, (b) stationary in growth rate with GHG ratios to the other variables bounded above at their 75th percentile level of the 1990-2012 sample, and (c) are stationary in growth rate with GHG ratios to the other variables bounded above at their maximum level of the 1990-2012 sample.

While there are an infinite number of abatement and offset supply scenarios one might study, we present three scenarios that we consider to be reasonable and realistic. For each of the supply scenarios, we assume a fixed supply quantity from complementary measures, reshuffling, and offsets, and we assume a fixed elasticity of supply for each of the price-sensitive sources.

1) **Scenario 1, Low availability:** low/medium complementary measures (185 MMT), low/medium levels of reshuffling (180 MMT), low/medium offset availability (90 MMT), medium consumer response to prices (due to weak fuel efficiency standards in complementary measures)
2) **Scenario 2, Medium availability**: Medium complementary measures (233 MMT), medium reshuffling (240 MMT), medium offset availability (110 MMT), low consumer response to prices
3) **Scenario 3, High availability:** High/medium complementary measures (282 MMT), high/medium reshuffling (300 MMT), high/medium offset availability (123 MMT), medium consumer response to prices.

[32] For example, if inflation were anticipated to be 2% per year, the nominal auction reserve price in 2020 would be \$17.18. If investors' anticipated some new sales of allowances in 2020 and their cost of capital was 3% per year, then the effective economic price floor in 2012 would be \$17.18 discounted back to 2012 at 5% per year, or \$11.63, rather than \$10.

We consider the medium availability scenario a good center of the possible outcomes. It is unlikely that all the low all the high cases for abatement and offset factors would occur, so we consider low/medium cases and high/medium cases as the bounds on likely outcomes in availability of abatement and offsets.

We put these together with the predetermined allowance supply available (not counting allowances in the price containment reserve) to determine the supply through 2020 at prices below the lower trigger price for the containment reserve. At prices between the lower and upper trigger price for the containment reserve, we also added in the available supply from the containment reserve.

We then combine the supply scenarios with the distribution of demand for greenhouse gas allowances under the three estimation methods discussed in Section III to determine the probabilities that the market outcome will fall in each of the four price ranges discussed above. Figure 5 shows these probabilities using each of the three demand estimation methods and each of the three supply scenarios.

We focus on the estimation method using the 75th percentile of sample bound for the ratio of GHG to other factors in the VECM and on the medium availability supply scenario, the middle case of the nine bars in Figure 5. That bar suggests that by 2020 there is an 80% probability that the allowance price will be at or near the auction reserve price, a 1% probability that it will be substantially above the auction reserve price, but still below the lowest price at which the containment reserve allowances can be sold, a 8% probability that the price will be within the range of the containment reserve, and an 11% probability that the containment reserve will be exhausted.

The other bars show the direction of variability: more supply raises the probability of a low price and lowers the probability of exhausting the containment reserve, and the low supply scenario has the opposite effect. There is little difference between the results of the demand estimation using the median GHG ratio to other factors as the upper bound and the results using the 75th percentile ratio as the upper bound. Using the maximum ratio at the upper bound substantially widens the possible demand outcomes and raises the probability of exhausting the containment reserve.

The results are consistent with the discussion in Section II. We conclude that there is a high probability that the market price will be near the auction reserve price in 2020, a small but significant probability that the price will be high enough to trigger release of some or all of the allowances in the price containment reserve, and very little chance that the price will be in the intermediate range where price-responsive abatement actions are the primary factor that balance of supply and demand.

IX. CONCLUSION

Economists have for decades advocated using market mechanisms to reduce pollution externalities. California has now embarked on a plan to reduce greenhouse gas emissions through such a market mechanism, a cap and trade program. The prices that will result in the program will depend on the demand for the emissions allowances, resulting from firms and individuals who wish to engage in GHG-emitting activities, and the supply of both emissions allowances and the ability to reduce emissions.

We have shown that there is significant uncertainty in both the demand and supply in this market. Furthermore, it seems likely that the great majority of abatement supply that is available at prices below the price containment reserve level will be available at prices near the auction reserve. As a proportion of the market, our analysis indicates that fairly little additional supply will be forthcoming at prices substantially above the auction reserve price, but below the lowest price of the containment reserve. Combined with the uncertainty in the demand for allowances, this suggests that the market price is unlikely to fall in an intermediate range substantially above the auction reserve price, but still below the level at which allowances from the price containment reserve would be made available. Our analysis also suggests that there is a small, but not insignificant, chance that the demand for emissions allowances could exceed the available supply after accounting for abatement activity and the supply of emissions offsets. This possibility supports the view expressed by ARB in October 2012 that it is prudent to pursue further policies that would prevent the price from skyrocketing if demand for emissions allowances turned out to be much stronger than expected.

It is important to note that the scenarios under which the price for emissions could climb very high by 2020 may not produce high prices in 2013. High prices towards the end of the program would result from unexpectedly strong demand and/or low abatement/offset supply over the years 2013-2020. Our analysis suggests that such outcomes are plausible, but are not the most likely outcome. The price of allowances in 2013 reflects the full distribution of potential supply/demand outcomes that could occur over the life of the program. If demand for allowances turned out to be higher than expected over the subsequent years (owing most likely to stronger than expected economic growth in the state) or the supply of abatement/offsets were lower than expected (owing to smaller effects of complementary policies than anticipated, smaller offset supply than anticipated, or other factors) then we would expect that the market price would gradually increase over these years to reflect the increased probability that a shortage of allowances could occur by the end of the program.

The potential for there being a range of outcomes in which the supply of abatement/offsets is very price inelastic (i.e., a steep supply curve) also raises concerns that small changes in the demand for allowances might have substantial effects on the allowance price. Such a situation is at least a warning that there might be the potential for non-competitive activities by some market participants that could artificially inflate or depress the price. In ongoing work, we are examining these possibilities in more detail.

Figure 1
Supply of Abatement

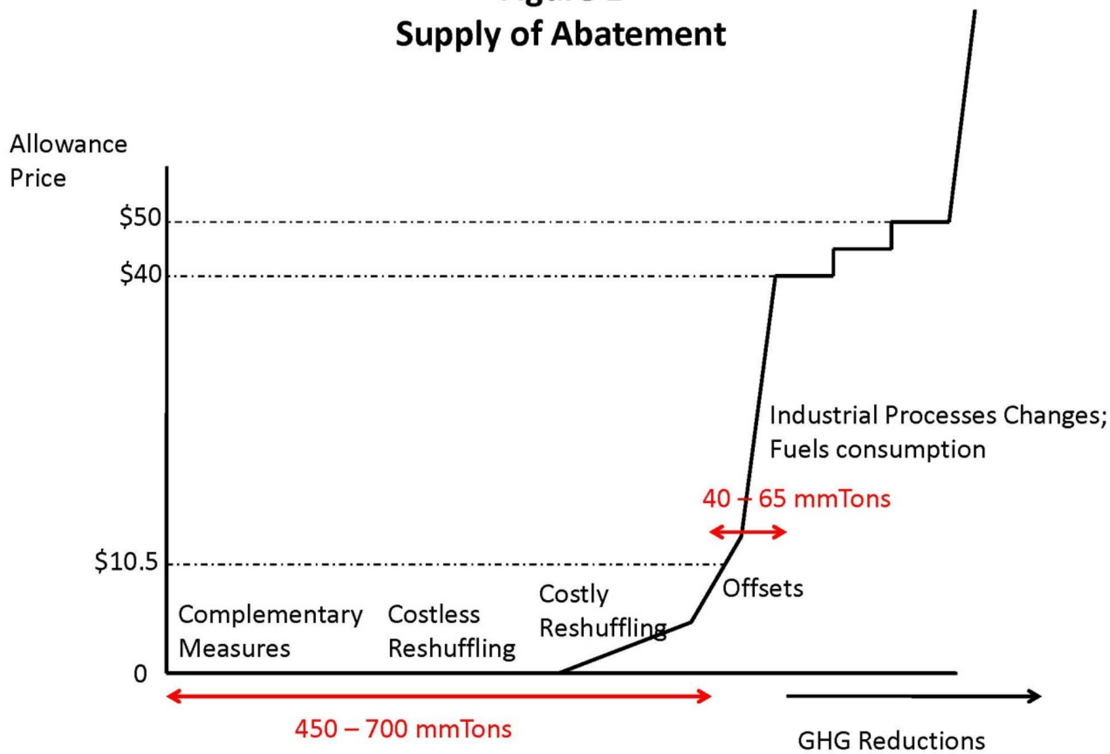


Figure 2
Hypothetical Distribution of Abatement Demand (BAU minus Allowances Outside Containment Reserve) vs Abatement Supply

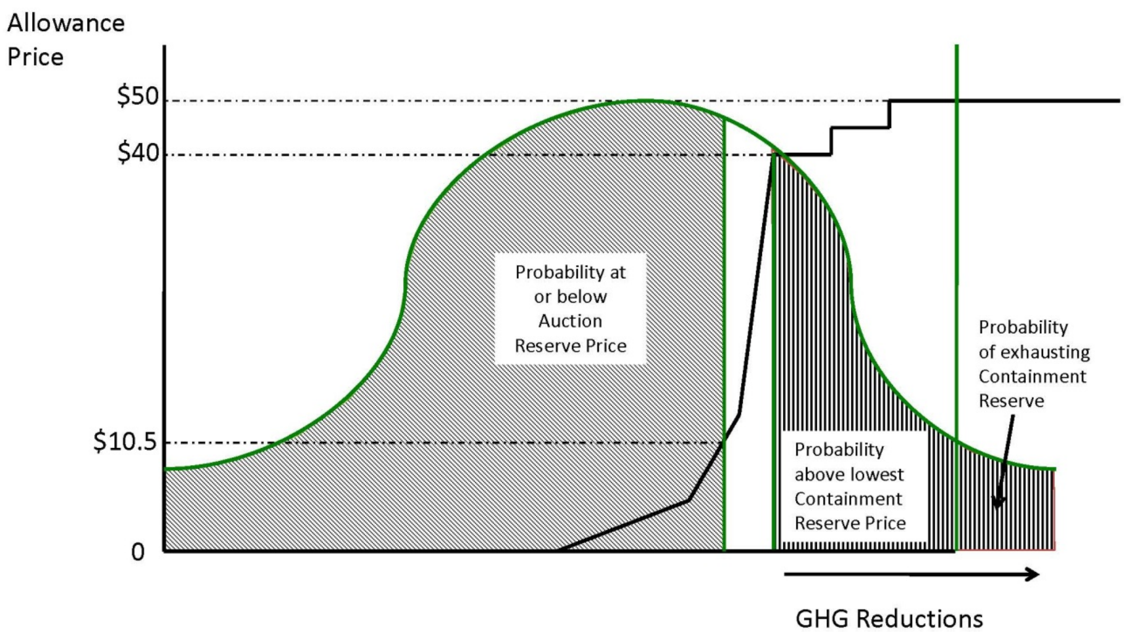


Figure 3
Possible Density Functions of Allowance Price

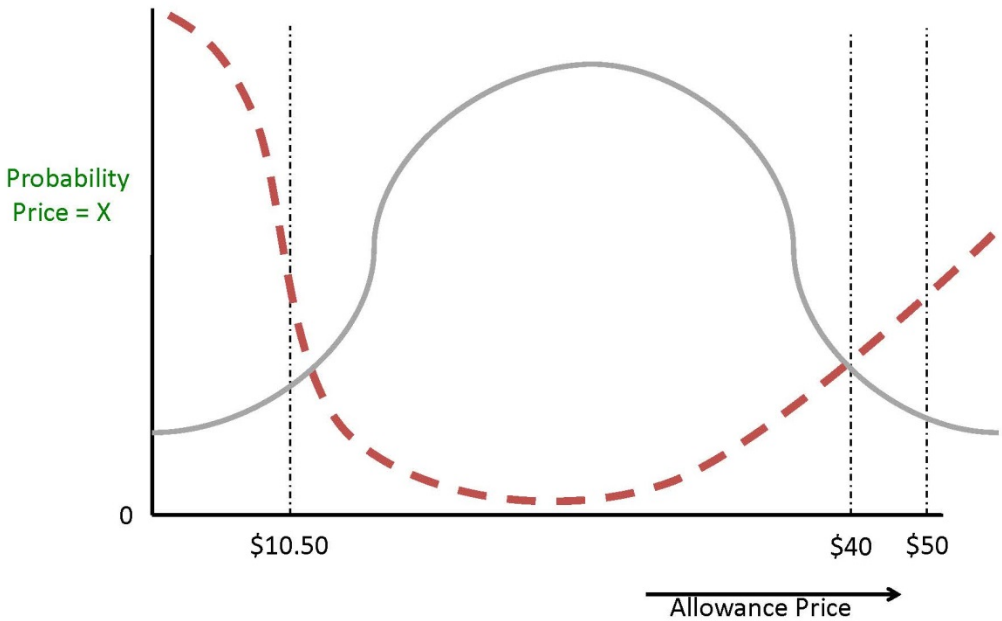


Figure 4a
Estimated Business-As-Usual Emissions

(with GHG Ratios to Other Factors Bounded Above at Median Levels)

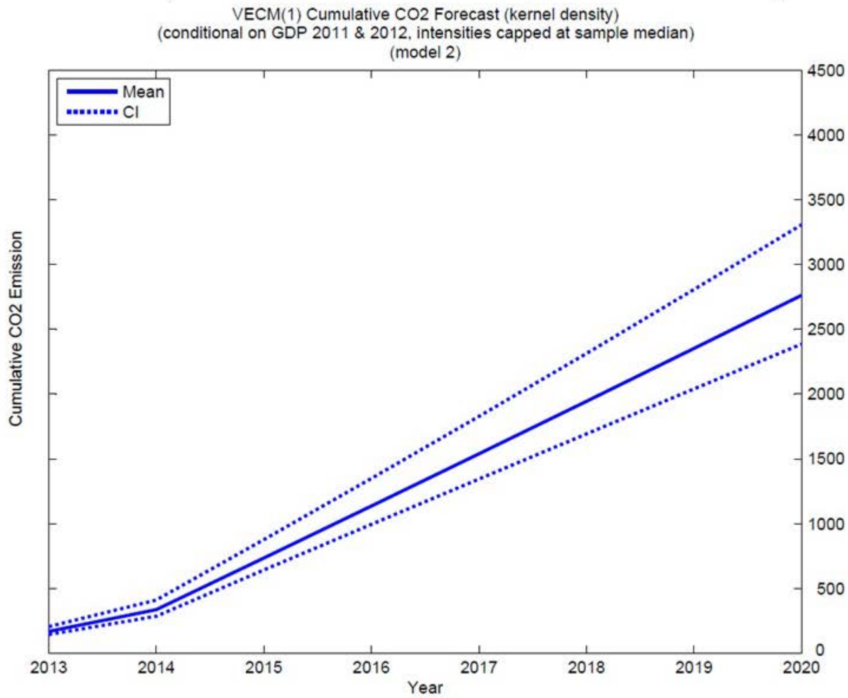


Figure 4b

Estimated Business-As-Usual Emissions

(GHG Ratios to Other Factors Bounded Above at 75th Percentile)

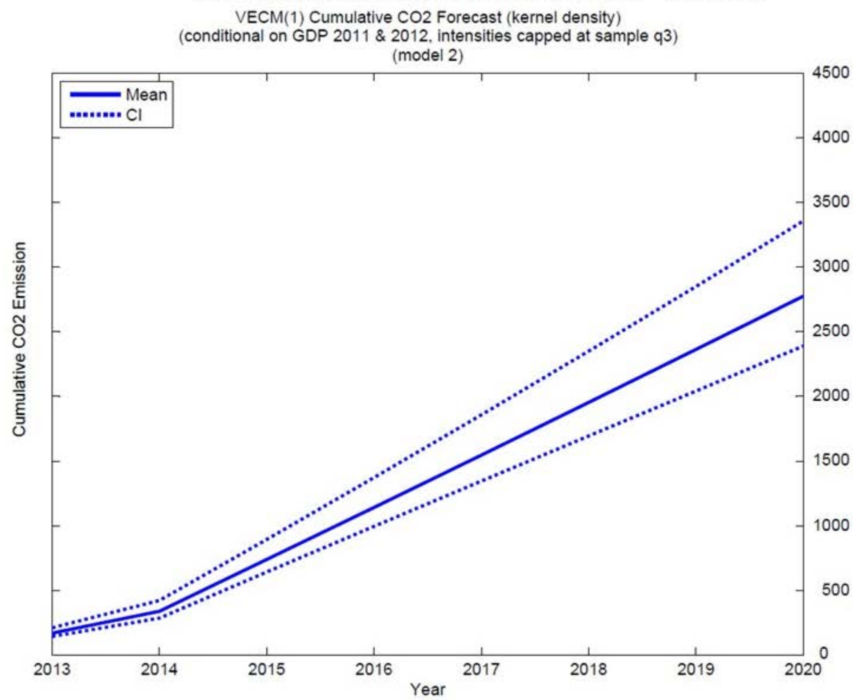


Figure 4c
Estimated Business-As-Usual Emissions

(GHG Ratios to Other Factors Bounded Above at Maximum)

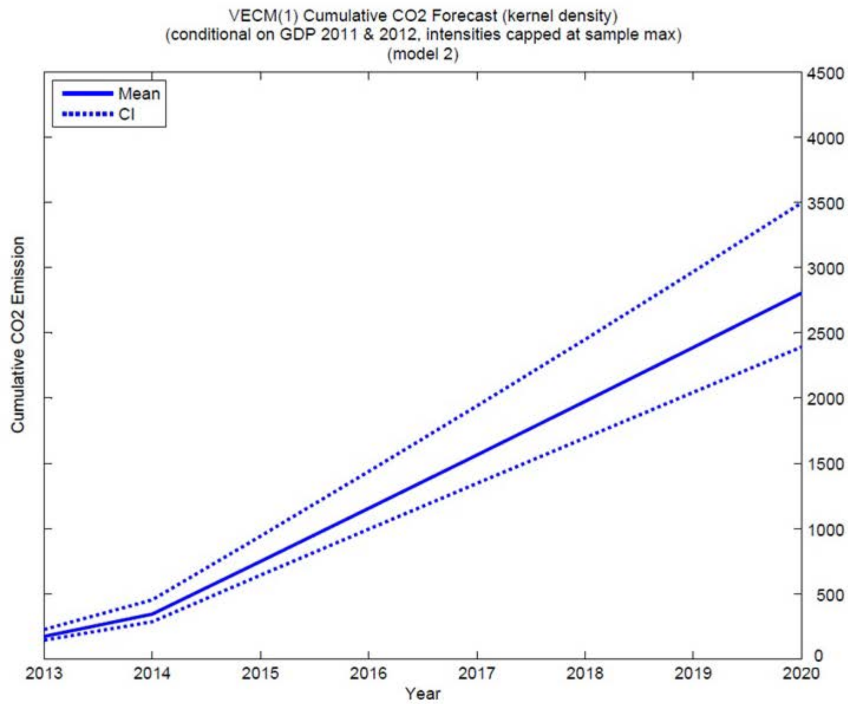
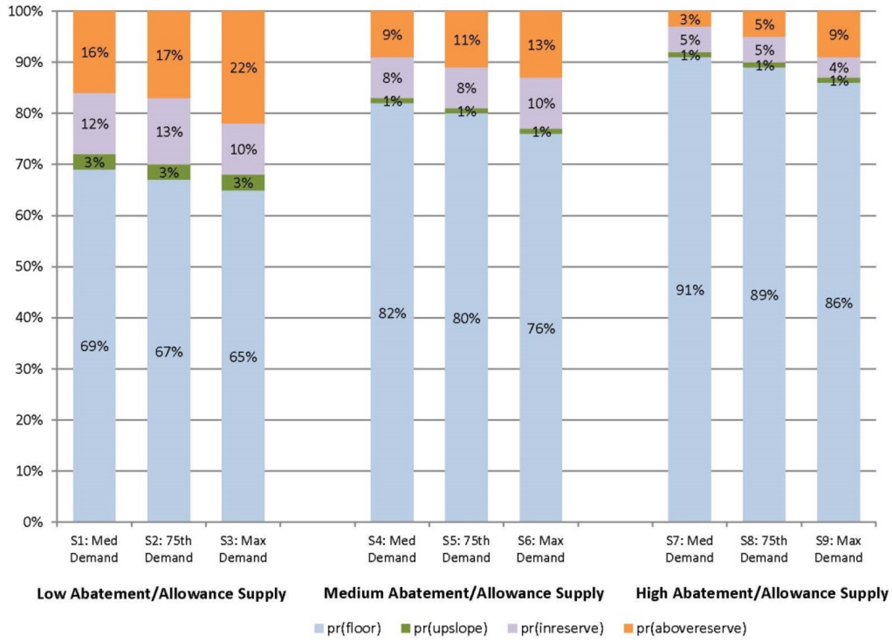


Figure 5
Allowance Price Probabilities by Scenario



ENERGY INSTITUTE AT HAAS

EI @ Haas WP 236

Downstream Regulation of CO2 Emissions in California's Electricity Sector

James Bushnell, Yihsu Chen and Matthew Zaragoza-Watkins

January 2013

This paper is part of the Energy Institute at Haas (EI @ Haas) Working Paper Series.
EI @ Haas is a joint venture of the Haas School of Business and the UC Energy Institute that brings together research and curricular programs on energy business, policy and technology commercialization.

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Downstream Regulation of CO2 Emissions in California's Electricity Sector

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January, 2013

Abstract

This paper examines the implications of alternative forms of cap-and-trade regulations on the California electricity market. Specific focus is given to the implementation of a downstream form of regulation known as the first-deliverer policy. Under this policy, importers (i.e., first-deliverers) of electricity into California are responsible for the emissions associated with the power plants from which the power originated, even if those plants are physically located outside of California. We find that, absent strict non-economic barriers to changing import patterns, such policies are extremely vulnerable to reshuffling of import resources.

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1 Introduction

A central problem faced by regulators in implementing climate change policy is the limit of their regulatory jurisdiction. While greenhouse gas (GHG) emissions can be controlled locally, the damages associated with them are felt globally. Thus GHG emissions reductions are a global public good, and local restrictions, voluntarily undertaken by some jurisdictions, can be seriously undermined by offsetting emissions increases elsewhere. Perhaps the most obvious way for polluters to circumvent an environmental regulation is to relocate the regulated facility and its polluting activities to another jurisdiction. Following the literature, we refer to this physical relocation of facilities as leakage (see, for example, Fowlie (2007) and Kuik and Gerlagh (2003)). There is also the phenomenon of demand-side leakage, whereby a local regulation that depresses demand for polluting goods in one region can lead to higher quantities demanded of the goods in unregulated regions (see Felder and Rutherford (1993)). We will focus here on supply-side leakage, although we comment on the relationship between demand-side leakage and reshuffling when we discuss reshuffling below.

When differentially applied across regions, mandates and standards can lead to leakage. For example, under the Clean Air Act (CAA), more stringent and costly emission standards apply to non-attainment areas. Research has demonstrated that industrial activity declines in non-attainment areas and is at least partially displaced by growth in attainment areas, where regulatory compliance is less costly (see Greenstone (2002) and Becker and Henderson (2000)). To the extent that this displaced production emits, pollution has leaked from the heavily regulated region to the more lax region.

Market-based regulations are equally vulnerable to the problems of leakage. For example, if one jurisdiction imposes a tax on emissions or establishes a cap-and-trade system, it will be more expensive for firms to produce their pollution-intensive goods in that region. This creates an incentive for firms to move some (or all) of their production elsewhere. They may accomplish this by producing slightly less from their regulated plants and more from their unregulated plants, or by moving their particularly pollution-intensive plants out of the regulated region.

One option in the regulatory tool-kit is to focus the regulation on the point in a vertical supply chain where local regulators can have the most leverage on total emissions. Functionally, such "vertical targeting" (see Bushnell and Mansur, (2012)) can limit extra-jurisdictional emissions increases by either limiting exports of carbon producing inputs or restricting imports of carbon-intensive products. The latter case, also known as "downstream regulation" can produce a related problem that can arise when regulations are imposed at the point of purchase, but where some consumers are subject to the policies and others are not.[1] If a sufficient percentage of the products affected by a regulation already complies with it, the policy's goals can be achieved by simply reshuffling who is buying from whom (see Bushnell, Peterman and Wolfram, (2009)). In cases, such as climate change, where the location of emissions has little impact on environmental damages, reshuffling can make the environmental policy completely ineffective, as it will not alter the rate at which the favored "clean" product is produced.

The reshuffling problem is similar to the conditions that limit the effectiveness of consumer boycotts. Although a percentage of motivated customers stops buying from the boycotted source, there will be no net impact on sales or prices if there are enough other customers who are indifferent to the cause of the boycott and willing to shift to the boycotted producers. As with an ineffective boycott, reshuffling is more likely when the share of unregulated products available is larger than the share of regulated products.

Note that both reshuffling and demand-side leakage affect demand outside the regulated area. Unlike demand-side leakage, however, reshuffling does not change total equilibrium consumption (or prices or emissions) of the regulated goods. Reshuffling requires that consumers inside the regulated region perceive the clean product to be a perfect substitute for the dirty product, and so substitute all their consumption to the clean product, while consumers outside the regulated region are indifferent between consuming clean or dirty goods, and so increase their consumption of the dirty goods. There is no such perfect substitute available with demand-side leakage. In fact, there is a duality between reshuffling and demand-side leakage, since if firms are able to reshuffle completely, there need be no change in prices and therefore no demand-side reaction to the regulation. It is only to the extent that firms are unable to avoid the regulation through reshuffling that there is a real reduction in emissions in the regulated jurisdiction through new, clean supply or reduced dirty consumption. In the latter case, there could be demand-side leakage if the reduced dirty consumption in the regulated region drives down the price for the product elsewhere.

In this paper we examine this issue in the context of the California cap-and-trade market for CO2 emissions. As described below, this market is highly dependent upon imported products, particularly electricity, and is therefore vulnerable to both leakage and reshuffling, depending upon the point of regulation. The current practice is to regulate the emissions of local sources, and the emissions associated with electricity imported into the State. These regulations would be accompanied by a series of additional measures intended to limit reshuffling.

We simulate the potential effectiveness of these additional measures by building a simulation model of this market. Electricity production, transmission, and emissions are recreated for a baseline year of 2007 for which detailed data on actual market conditions are available. Once this baseline simulation is constructed, we simulate several counterfactual emissions regulations to examine the emissions and price-effects of these designs.

We find that even a modest weakening of the additional measures targeted at limiting reshuffling will greatly undermine the strictness of the emissions cap through reshuffling.

2 Regulating the California Electric Sector: A Hybrid Approach

The Global Warming Solutions Act of 2006 (AB 32) calls for California to reduce GHG emissions to 1990 levels by 2020, and assigns the responsibility for developing a strategy for meeting the 2020 target to the California Air Resources Board (CARB). The AB 32 Scoping Plan, the document that details the approach adopted by CARB, includes a cap-and-trade program.

The cap-and-trade program establishes an aggregate cap covering approximately 85 percent of the States GHG emissions, and a system of tradable emissions permits that regulated facilities may use to meet their compliance obligations. The program covers emissions for the years 2013-2020, and is partitioned into three compliance periods. Beginning in 2013, emissions obligations will be assessed on industrial facilities and first deliverers of electricity to the California grid. Emissions associated with fossil transportation fuels and retail sales of natural gas are included in 2015, at the start of the second compliance period. The third compliance period runs from 2018 through 2020.

The California initiative is proceeding in advance of the broader-based Western Climate Initiative (WCI). The WCI would link cap-and-trade programs in British Columbia, California, Manitoba, Ontario, and Quebec, allowing covered entities to participate in a regional cap-and-trade allowance market, initially encompassing large stationary sources (primarily electricity) and then expanding to include other sources, including transportation fuels in a second phase.[2] At this time, only California and Quebec intend to link programs in the first compliance period, with additional jurisdictions potentially linking in future compliance periods.

California electric utilities serve their demand with power supplied by generation facilities they own, contracts with other generators or marketers, and short-term market purchases. Some generation is located in California and additional energy is imported from other states in the Western Interconnection. Californias end-user electric demand and in-state electric generation accounts for one-fourth of the emissions included under the statewide cap. Imported electricity is a significant energy and emissions source. In 2008, imported electricity accounted for approximately one-third of electricity supplied to the California grid, and half of electric sector emissions.

Recognizing that an accurate accounting of Californias GHG footprint would need to include emissions from imported electricity, and wary of emissions leakage, the California Legislature wrote a provision into AB 32 directing CARB to account for all emissions from out-of-state electricity delivered to and consumed in California. While the most parsimonious means of achieving this objective would be to directly regulate generators of electricity used to serve the California grid, California's limited jurisdiction does not allow for the direct regulation of out-of-state generation facilities. In order to meet the statutory obligation of AB 32, CARB developed a hybrid approach to regulating the electric sector. Under the hybrid approach, the first deliverer of electricity into the California grid faces the compliance obligation for emissions. For in-state generation the facility operators are considered the first deliverers. Operators of in-state facilities report facility emissions and net generation directly to CARB. Therefore, the source (and associated emissions) of the electricity is known. First deliverers of imported electricity are the marketers and retail providers who import energy into the California grid.

One significant limitation of this approach is the uncertainty associated with which emissions factor to attribute to imported power. Due to the nature of the Western Interconnection, electricity imports do not, in general, travel directly from generation facility to the California grid. Therefore, it is generally not possible to identify the source of imported electricity with sufficient granularity to assign a specific emissions obligation. California regulators address this uncertainty of the emissions factor by providing first deliverers the option of reporting a facility-specific emissions factor associated with the energy they are importing.

CARB, however, has set a high bar for importers wishing to claim a facility-specific emissions factor. In order to claim a facility-specific emissions factor the importer must provide three pieces of documentation: evidence that the facility was operating in the same hour that the power is claimed to have been scheduled into California; evidence that the importer possesses rights to the power generated by the facility; and evidence that the importer scheduled an equivalent amount of power from the generating facilitys balancing authority area into the California grid. In many cases, first-deliverers of imported electricity will not be able to provide this level of documentation. In such cases, CARB assigns first deliverers of imported energy a default emissions factor, which is meant to represent the most likely emissions factor associated with energy generated out-of-state to meet California load, discussed in greater detail below.

Historically unspecified power has made up a substantial share of imports. In the 2008 GHG Emissions Inventory, unspecified power accounted for approximately 57 percent of emissions associated with imported electricity.[3] Because of this, the treatment of unspecified power and the value of the default emissions factor will be central to an accurate accounting of emissions from imported power.

2.1 The Default Emissions Factor

In their Interim Decision, the California Public Utilities Commission (CPUC) recommended that CARB use a regional default emission factor of 1,100 lbs/MWh to represent unspecified electricity. This emission factor was meant to loosely approximate the most likely source of marginal generation, a less efficient gas fired generator located out-of-state and within the Western Interconnection. Subsequently, CARB collaborated with the California Energy Commission (CEC), CPUC, and other WCI jurisdictions to refine this number by developing a methodology for assigning an emission factor for unspecified power that would accurately reflect the emissions associated with marginal electricity.

The WCI working group settled on a default emission factor of 961lbs/MWh, (0.428MMT/MWh) representative of a fairly clean natural gas plant. The unspecified power emission factor is calculated as a rolling three-year average of the marginal plants in the Western Interconnection, where marginal plants are defined as facilities producing at 60% of generating capacity or less. The emission factor is then calculated using Energy Information Administration (EIA) fuel and net generation data and CARB fuel-specific emission factors.

The resources assumed available for marginal dispatch are largely natural gas facilities. Baseload and renewable sources are excluded from the WCI market emission factor calculation. Baseload facilities are typically large capacity sources, such as coal, large hydro, and nuclear power, that generate electricity at costs lower than natural gas facilities. Less expensive coal, nuclear power, and hydroelectricity are assumed to be fully committed to meet utility baseload in the Western Interconnection. More expensive renewable energy is assumed to be fully contracted by electric utilities in order to meet Renewable Portfolio Standard (RPS) compliance targets.

Under cap-and-trade, the prevalence of unspecified power will be influenced by the default emission factor. First deliverers and generators with lower emission factors will wish to specify their actual emissions factor in order to minimize the carbon costs associated with their output. If the emission factor is set too low firms will have an incentive to "launder" their higher emitting resources through the market to attain the lower, unspecified, emission factor. Laundering precipitates GHG emissions leakage, a phenomenon that AB 32 explicitly directs regulators to minimize, to the extent feasible. This may be of particular concern, due to the fact that many of the high emitting resources that first deliverers could seek to launder are baseload or otherwise operating at a high fraction of capacity. As a point of reference, the California Energy Almanac reports that in 2009 more than 20,000 GWhs of specified coal power were imported into California. If all of these resources were to somehow become unspecified, it would result in approximately 10 mmTons of paper emissions reductions. That quantity is roughly equivalent to the entire 2012 annual allocation of emissions allowances to the oil and gas extraction sector, the second largest industrial sector regulated under the program.

2.2 Additional Rules Limiting Emissions Leakage

The default emissions factor is not the only potential conduit for emissions leakage. Another undesirable behavior that stems from the first deliverer approach is reshuffling. Reshuffling could occur if low or zero GHG resources, which currently serve out-of-state baseload, were reassigned to California and higher emitting out-of-state resources, which currently serve California, were reassigned to serve the out-of-state baseload. As with laundering, significant reshuffling could undermine the integrity of the program. However, unlike laundering, reshuffling cannot be addressed by correctly setting the default emissions factor.

To address concerns about laundering and reshuffling, and in recognition of the fact that it would be very difficult for CARB to identify each instance of laundering or reshuffling, CARB has proposed an explicit prohibition of the behaviors. The prohibition works by requiring the individual responsible for reporting GHG emissions for each compliance entity to sign an attestation, under penalty of perjury, that they have not engaged in any scheme or artifice to claim GHG reductions that are not real. This approach, with a lack of detail defining exactly what reshuffling was, has been extremely controversial. On August 8th, Federal Energy Regulatory Commissioner Phillip Moeller issued an open letter to California Governor Jerry Brown expressing concern over the " uncertainty and great concern among entities selling into California" caused by "failing to define resource shuffling, but nevertheless prohibiting it." On August 16th, CARB Chair Mary Nichols responded that the agency would suspend enforcement of the provision for at least 18 months to help avoid any negative impact on electricity supplies to California.

3 Analysis of Cap-and-Trade Design

Our focus is on the specific design of the cap-and-trade mechanism, and its impact on the operation of electricity markets. Therefore the focus here is on a "short-term" time frame. We base our analysis upon actual market data drawn from the year 2007, and look at the counter-factual question of how those markets would have functioned under a cap-and-trade regime. In this sense the work follows in the spirit of Fowlie (2009), who also studies the potential for leakage from a California-only market, and also that of Bushnell and Chen (2008) who deploy similar techniques to examine allowance allocation policies in a purely source-based allowance trading regime.

In a fashion similar to Zhao, et al., (2010), we formulate the joint equilibrium outcomes of the emissions and electricity market as a linear-complementarity problem. Unlike Zhao, et al. (2010), and Fowlie, et al. (2010) we do not study the implications for updating policies on plant investment or retirements. In this sense our model, while dynamic, is focused on short-run operational decisions.

Our study differs from previous work in several important ways. While Fowlie (2009) models portions of the western electricity market, we model the emissions credit prices as endogenous to the cap-and-trade market. This is central to our work given our focus on the endogenous impact of allocation policies on permit prices. Second, we explicitly model the first-deliverer aspects of the AB 32 policies. To our knowledge, this is the first empirical study directed at this topic. Previous work examining the impacts of allocation have either taken a general equilibrium approach (Bohringer and Lange (2005), Sterner and Muller (2008), Fischer and Fox (2008), or applied more complex formulations to stylized market data (Chen et al., 2011, Zhao, et al., 2010, Neuhoff, et al., 2006). Except Chen et al. (2011), all these papers, including Bushnell and Chen (2011), which is closely related to this one, model a purely source-based system.

3.1 Model

In this section, we first describe our equilibrium model and then discuss how we apply data from various sources to arrive at our calculations.

We assume here that firms act in a manner consistent with perfect competition with regards to both the electricity and emissions permit markets.[4] As such, the solution stemming from a perfectly competitive market is equivalent to the solution of a social planner's problem of maximizing total welfare.

The key variables and parameters of the model are grouped according to four important indices: the origin, destination, plant, and time period of production. The total production of plant p from location i exported to location j, at time t is represented by $q_{p,i,j,t}$. Production costs $C_p(q_{p,t})$, vary by firm, technology, and location, and are constant for each plant and are unchanging over time.

$$C_p(q_{p,t}) = c_p q_{p,t}$$

where $q_{p,t} = \sum_j q_{p,i,j,t}$. Total emissions by firm and technology are determined by a constant emissions rate e_p and denoted $e_p(q_{p,t}) = e_p * q_{p,t}$.

Wholesale electricity is assumed to be a homogenous commodity for purposes of setting wholesale prices, although prices are assumed to vary by location subject to transmission constraints as described below. For each time period $t \in \{0, ..., T\}$, a perfectly competitive market outcome is obtained by solving the following welfare maximizing problem:

$$\int_0^{Q_{j,t}} P_{j,t}(Q)dQ - \sum_p C_p(q_{p,t}), \tag{1}$$

where $P_{j,t}(Q)$ gives the power prices in location j in period t, and $Q_{j,t} = \sum_{p,i} q_{p,i,j,t}$. The output $q_{p,t}$ is further limited by its capacity: $q_{p,t} \leq \bar{Q}_p$. The electricity sales are also subject to cap-and-trade regulation that will also be discussed below.

3.2 First-Deliverer Enforcement

As discussed above, one mechanism that can at least partially combat leakage is regulating emissions from imports by applying the emissions obligation on first deliverers of electricity to the grid. In the case of imported power, this requires importers of power to acquire emissions allowances and offsets equal to the measured or estimated emissions of the sources from which the imported power is claimed to originate. In addition, power plants within California will be required to cover their emissions with compliance instruments, following a more conventional "source-based" paradigm.

We model this hybrid design by establishing the cap constraint in terms of both in-state emissions and emissions from sources "exporting" power into California. Therefore, emissions from electricity production falls into two categories, that within the region covered by the emissions cap and that outside the reach of the regulation. The following constraint is imposed to model the cap-and-trade regulation:

$$\sum_{p,(i,j) \in REG,t} e_p q_{p,i,j,t} \leq CAP, \tag{2}$$

where the parameter CAP denotes the total cap in the cap-and-trade regulation, and the set REG represents those pairs of "origins" and "destinations" for electricity sales that are subject to the cap-and-trade regulation. If the source-based is considered, REG refers to the pairs with which the origin region i is California.

3.3 Additional Regulatory Measures

One challenge we faced when modeling the Western Electricity Coordinating Council (WECC) market is the lack of information about the power plants that are not required to report in the Environmental Protection Agencys Continuous Emission Monitoring System (CEMS). We therefore assigned a zero emission rate to those units since historically they are dominated by renewables and hydro facilities. Because these units are assigned with a zero emission rate, allowing them to freely determine their sale destination is likely to create an unrealistic re-shuffling opportunity, and thereby bias the effects of cap-and-trade regulation. We therefore assume that the power sales of those "NONCEMS" units are not changed in response to the cap-and-trade regulation and fix their sales $q_{p,i,j,t}$ at their levels prior to cap-and-trade regulation. To examine the sensitivity of this assumption on the market outcomes, we later relax it by allowing 10% of the NONCMES outputs to optimize their destination under the cap-and-trade regulation.

Another modeling detail that also requires additional explanation is the treatment of existing or legacy contracts. Historically, some facilities outside of California are partially owned by the California utilities. Therefore, some percentages of their output is designated to be imported into the corresponding utility's service territory by conditions specified in these contracts. Assuming that these contracts are maintained, no accounting for them would inflate the flexibility of the market and overestimate the re-shuffling effects. We treat contractual obligations as applying to percentages of a plant's output. With this added constraint, the only way a California utility can reduce its emissions from a contracted plant is through a reduction in the overall output of that plant. Again, this constraint only applies if we assume such contracts are maintained through their current lifetimes. We explore the implications of this assumption in later sections.

Finally, we follow the proposals considered by CARB to apply a default emission rate to account for the emissions from the unspecified imports. This arises from a situation in which the emissions of the imports delivered to the California pool-typed markets cannot be unambiguously identified. This regulatory measure allows those plants with an emission rate that is above the default emission rate to circumvent high emissions costs when selling their power into the California markets.

3.4 Transmission Network Management

We assume that the transmission network is managed efficiently in a manner that produces results equivalent to those reached through centralized locational marginal pricing (LMP). For our purposes this means that the transmission network is utilized to efficiently arbitrage price differences across locations, subject to the limitations of the transmission network. Such arbitrage could be achieved through either bilateral transactions or a more centralized operation of the network. For now we simply assume that this arbitrage condition is achieved.

Mathematically, we adopt an approach utilized by Metzler,et al. (2003), to represent the arbitrage conditions as another set of constraints of the market equilibrium. Under the assumptions of a direct-current (DC) load-flow model, the transmission 'flow' induced by a marginal injection of power at location l can be represented by a power transfer distribution factor, $PTDF_{lk}$, which maps injections at locations, l, to flows over individual transmission paths k. Within this framework, the arbitrage condition will implicitly inject and consume power, $y_{l,t}$, to maximize available and feasible arbitrage profits as defined by

$$\sum_{l \neq h} (p_{h,t} - p_{l,t})\, y_{l,t}.$$

In the above arbitrage equation, the location h is the arbitrarily assigned "hub" location from which all relative transmission flows are defined. Thus an injection of power, $y_{l,t} \geq 0$, at location l is assumed to be withdrawn at h. This arbitrage condition is subject to the flow limits on the transmission network, particularly the line capacities, T_k:

$$-\overline{T}_k \leq PTDF_{l,k} \cdot y_{l,t} \leq \overline{T}_k.$$

4 Data Sources and Assumptions

We utilize detailed hourly load and production data for all major fossil-fired and nuclear generation sources in the western U.S. Our primary sources are FERC form 714, which provides hourly system demand for major utility control areas, and the EPA Continuous Emission Monitoring System (CEMS) data, which provide hourly output for all major fossil-fired power plants. The CEMS data cover all major utility level sources of CO2, but we do not model output from nuclear, combined-heat and power, wind, solar, or hydro sources.

These hourly data are aggregated by region to develop the "demand" in the simulation model. As discussed below, for purposes of the cap-and-trade simulations, the relevant demand is in fact the residual demand; the demand that is left after applying the output from non-CEMS plants. These data are combined with cost data to produce cost and emissions estimates for each of the 419 generation units in the CEMS database.

These data are then combined to create demand profiles and supply functions for periods in the simulation. Although hourly data are available, for computational reasons we aggregate these data into representative time periods. There are 20 such periods for each of the four seasons, yielding 80 explicitly modeled time periods. As California policy was the original focus of this work, the aggregation of hourly data was based upon a sorting of the California residual demand. California aggregate production was sorted into 20 bins based upon equal MW spreads between the minimum and maximum production levels observed in the 2007 sample year. A time period in the simulation therefore is based upon the mean of the relevant market data for all actual 2007 data that fall within the bounds of each bin.

The number of season-hour observations in each bin is therefore unbalanced, there are relatively few observations in the highest and lowest production levels, and more closer to the median levels. The demand levels used in the simulation are then based upon the mean production levels observed in each bin. In order to calculate aggregate emissions, the resulting outputs for each *simulated* demand level was multiplied by the number of *actual* market hours used to produce the input for that simulated demand level. For example, every actual hour (there were 54) during Spring 2007 in which California residual demand fell between 6949 and 7446 MW were combined into a single representative hour for simulation purposes. The resulting emissions from this hour were then multiplied by 54 to generate an annualized equivalent total level of emissions.

In the following sub-sections, we describe further the assumptions and functional forms utilized in the simulation.

4.1 Market Demand

Aggregate demand is taken from FERC form 714, which provides hourly total end-use consumption by control-area and is aggregated to the North American Electric Reliability Commission (NERC) sub-region level. As described below a large portion of this demand is served by generation with effectively no CO2 emissions, such as nuclear and hydro sources. This generation needs to be netted out from total demand to produce a residual demand to be met by GHG producing fossil sources.

End-use consumption in each sub-region is represented by the demand function $Q_{l,t} = \alpha_{l,t} - \beta_l p_{l,t}$, yielding an inverse demand curve defined as

$$p_{lt} = \frac{\alpha_{l,t} - \sum_{i,j} q_{i,j,t} - y_{i,t}}{\beta_l}$$

where $y_{i,t}$ is the aggregate net transmission flow into location l. The intercept of the demand function is based upon the actual production levels in each location calculated

Table 1: Derated Generation Capacity (MW) by Region and Fuel Type

Region	Coal	CCGT	Gas St	Gas CT	Oil	Total
CA	0	10823	12430	2728	496	26477
IM	1405					1405
NW	9716	4506	610	1235		16068
RM	5596	1476	96	1659		8826
SW	8652	11623	1751	1042		23068
Total	25369	28429	14887	6664	496	75845

Table 2: Energy Production (GWh) by Region and Fuel Type

Region	Coal	CCGT	Gas St	Gas CT	Oil	Non-CEMS
CA	0	66607	12898	1836	144	117766
IM	14407	0	0	0	0	0
NW	84321	24017	1884	1387	0	113553
RM	49534	9420	10	2236	0	1529
SW	75292	51184	2937	1374	0	63286
Total	223554	151228	17729	6833	144	296134

as described above. In other words, we model a linear demand curve that passes through the observed price-quantity pairs for each period. As electricity is an extremely inelastic product, we utilize an extremely low value for the slopes of this demand curve. For each region, the regional slope of the demand curve is set so that the median elasticity in each region is -.05.[5]

4.2 Hydro, Renewable and other Generation

Generation capacity and annual energy production for each of our regions is reported by technology type in Tables 1 and 2. We lack data on the hourly production quantities for the production from renewable resources, hydro-electric resources, combined heat and power, and small thermal resources that comprise the "non-CEMS" category. By construction, the aggregate production from these resources will be the difference between market demand in a given hour, and the amount of generation from large thermal (CEMS) units in that hour. In effect we are assuming that, under our CO2 regulation counter-factual, the operations of non-modeled generation (e.g., renewable and hydro) plants would not have changed. This is equivalent to assuming that compliance with the CO2 reduction goals of a cap-and-trade program will be achieved through the reallocation of production within the set of modeled plants. We believe that this is a reasonable assumption for two reasons. First the vast majority of the CO2 emissions from this sector come from these modeled resources. Indeed, data availability is tied to emissions levels since the data are reported through environmental compliance to existing regulations. Second, the total production from "clean" sources is unlikely to change in the short-run. The production of low carbon electricity is driven by natural resource availability (e.g., rain, wind, solar) or, in the case of combined heat and power (CHP), to non-electricity production decisions. The economics of production are such that these sources are already producing all the power they can, even without additional CO2 regulation. To a first-order, short-run emissions reductions will have to come either from shifting production among conventional sources, a reduction in end-use electricity demand, or through substitution with unregulated imports, *i.e.*, leakage or reshuffling.[6]

4.3 Fossil-Fired Generation Costs and Emissions

We explicitly model the major fossil-fired thermal units in each electric system. Because of the legacy of cost-of-service regulation, relatively reliable data on the production costs of thermal generation units are available. The cost of fuel comprises the major component of the marginal cost of thermal generation. The marginal cost of a modeled generation unit is estimated to be the sum of its direct fuel, CO2, and variable operation and maintenance (VO&M) costs. Fuel costs can be calculated by multiplying the price of fuel, which varies by region, by a unit's 'heat rate,' a measure of its fuel-efficiency.

The capacity of a generating unit is reduced to reflect the probability of a forced outage of each unit. The available capacity of generation unit i, is taken to be $(1 - fof_i) * cap_i$, where cap_i is the summer-rated capacity of the unit and fof_i is the forced outage factor reflecting the probability of the unit being completely down at any given time.[7] Unit forced outage factors are taken from the generator availability data system (GADS) data that are collected by the North American Reliability Councils. These data aggregate generator outage performance by technology, age, and region.

Generation marginal costs are derived from the costs of fuel and variable operating and maintenance costs for each unit in our sample. Platts provides a unit average heat-rate for each of these units. These heat-rates are multiplied by a regional average fuel cost for each fuel and region, also taken from Platts. Marginal cost of each plant p is therefore constant:

Table 3: Average Emissions Rates (Tons/MWh) by Region and Fuel Type

Region	Coal	CCGT	Gas St	Gas CT	Oil
CA	NA	0.425	0.583	0.822	0.837
IM	1.011	NA	NA	NA	NA
NW	1.093	0.437	0.639	0.826	NA
RM	1.126	0.420	0.792	0.828	NA
SW	1.081	0.398	0.627	0.856	NA

$$C_p(q^i_{p,t}) = c_p q_{p,t}.$$

Emissions Rates

Emissions rates, measured as tons CO2/MWh, are based upon the fuel-efficiency (heat-rate) of a plant and the CO2 intensity of the fuel burned by that plant. The average emissions rates of all facilities are summarized by region in Table 3.

4.4 Transmission Network

Our regional markets are highly aggregated geographically. The region we model is the electricity market contained within the U.S. portion of the Western Electricity Coordinating Council (WECC). The WECC is the organization responsible for coordinating the planning investment, and general operating procedures of electricity networks in most states west of the Mississippi. The multiple sub-networks, or control areas, contained within this region are aggregated into four "sub-regions." Between (and within) these regions are over 50 major transmission interfaces, or paths. Due to both computational and data considerations, we have aggregated this network into a simplified 5 region network consisting primarily of the 4 major subregions.[8] Figure 1 illustrates the areas covered by these regions. The states in white, plus California, constitute the US participants in the WECC.

Given the aggregated level of the network, we model the relative impedance of each set of major pathways as roughly inverse to their voltage levels. The network connecting AZNM and the NWPP to CA is higher voltage (500 KV) than the predominantly 345 KV network connecting the other regions. For our purposes, we assume that these lower voltage paths yield 5/3 the impedance of the direct paths to CA. Flow capacities over these interfaces are based upon WECC data, and aggregate the available capacities of aggregate transmission paths between regions.

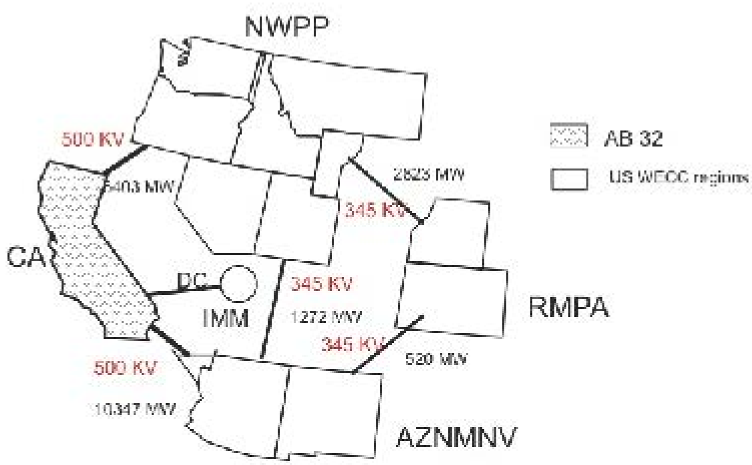

Figure 1: Western Regional Network and Cap-and-Trade Regions

5 Results

In this section we discuss the implications of different degrees of enforcement of various anti-reshuffling elements in the market, as well as contrast these results to alternative hypothetical cap-and-trade designs. We begin with a discussion of the baseline simulation. The impacts of the regulation are based upon changes from this baseline, no-cap scenario to the counter-factual simulations with various forms of the regulation.

5.1 Baseline Simulations

For the baseline year of 2007 we first simulate production in the WECC to establish a baseline level of production, emissions, and emissions associated with imports into California. Figure 2 summarizes energy production and the associated emissions from the baseline run and from the actual CEMS data. The model assumptions manage to recreate aggregate baseline emissions by source reasonably accurately. Total WECC-wide emissions from the baseline simulation are 345 mmTons compared to 341 tons in the CEMS data. Baseline emissions in each region are within 7% of baseline in each region.

For an evaluation of the first-deliverer elements of the regulation, it is necessary to establish a baseline level not only of emissions *sources* but of emissions based upon *consumption*. This means simulating the pair-wise matching of specific destinations to the production from each power plant. It is important to recognize that this matching of sources to consumption does not affect the overall power-flow or any other constraint associated with the physical production, which is simulated based upon an assumption of social-welfare maximization. The matching just serves to establish baseline estimates of the emissions associated with consumption in different regions.

We begin by applying several restrictions from known contractual and ownership relationships to California power. We focused on the relationships between California Load Serving Entities (LSE) and coal facilities located in other regions of the WECC using information provided to us from E3 consulting. These historic relationships are summarized in Table 4. The baseline model requires that these production percentages be delivered into California from each of these facilities. Otherwise, the model finds the optimal dispatch and assigns destinations without any additional constraints. In the case of a baseline simulation, absent any costs associated with emissions, there are multiple solutions to this matching of sources and destinations. Our simulation produced emissions associated with California consumption of around 108 mmTons, which is close to the values given in the 2007 GHG inventory calculations from CARB.

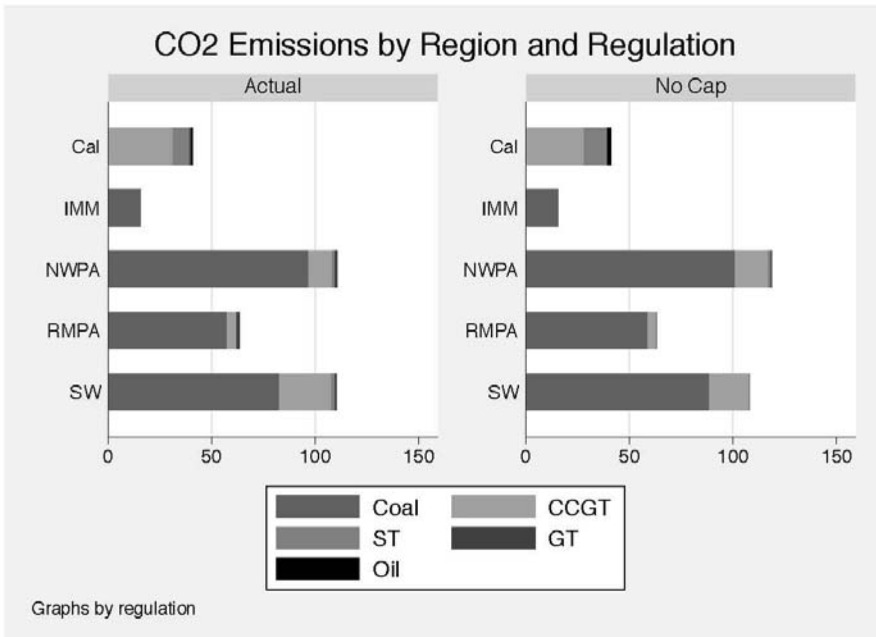

Figure 2: Actual Emissions and Simulation Results

Table 4: Energy (GWh) and Emissions (mmTons) Consumed in CA.

Plant	Units	Location	Fuel Type	CA Share	Contract?
Boardman	1	OR	Coal	23.5%	Yes
Four Corners	4 & 5	NM	Coal	48.0%	NA
Intermountain	1 & 2	UT	Coal	78.9%	No
Navajo Station	1- 3	AZ	Coal	21.2%	Yes
Reid Gardner	4	NV	Coal	67.8%	Yes
San Juan	3	NM	Coal	41.8%	No
San Juan	4	NM	Coal	38.7%	No
Bonaza	1	UT	Coal	26 MW	Yes
Hunter	2	UT	Coal	26 MW	Yes

Table 5: Energy (GWh) and Emissions (mmTons) Consumed in CA.

Source	Energy	Emissions
Coal	53210	61.99
CCGT	73414	33.66
Gas St.	20922	11.43
Gas CT	473	0.28
Oil	2195	1.84
Hydro/Nuke/other	134194	0
Totals	284409	109.2

Table 5 summarizes the sources of power consumed in California under our baseline simulation. Note that, beyond Table 4 we do not have access to further detailed matching data so, unlike with source emissions, we are unable to compare the baseline to actual observations. The Four Corners facilities are included in the baseline - as they were providing power into CA during 2007 - but have since been divested and are therefore not included in the restrictions to first-deliverer sources described below.

5.2 Cap-and-Trade Results

Having established baseline levels of imports into California, we simulate several alternative implementations of a cap-and-trade regime on the California market. The alternative scenarios include the following.

- A source-based regulation applied only to California sources
- A source-based regulation applied to California sources, with first-deliverer measures applied to imports into California. One dimension in which the first-deliverer policy may vary is in the assumed emissions (default) of 'generic' power imported through an exchange-based market or other transactions. We examined several alternatives for this default rate, and report here the results for 428 tons/GWh, the current practice, and for 1000 tons/GWh, roughly the emissions rate of an efficient coal plant. In addition, we model three alternative additional restrictions on the first-deliverer rules.
  - Historic imports from contracted and owned coal facilities (except Four Corners) and non-CEMS sources must be maintained at the same (baseline) level.

Table 6: Summary of Results with 15% Reduction in CO2

Outcome	Region	No Cap	Source Based Cap	First Del. 428 Default	First Del. 1000 Default	WECC wide cap
Permit Price		-	12.77	0.00	0.00	35.26
Emissions mmTons	Cal	41.17	35.00	41.17	41.17	38.83
	NW	118.78	121.51	118.78	118.78	117.58
	SW	107.89	110.20	107.89	107.89	96.00
	RM	63.07	63.35	63.07	63.07	62.32
	IM	15.74	15.74	15.74	15.74	15.57
	Total	346.65	345.80	346.65	346.65	330.45
Elec. Prices Avg. $/MWh)	Cal	61.63	66.28	61.63	61.63	80.05
	NW	68.32	75.57	68.32	68.32	88.74
	SW	54.93	56.55	54.93	54.93	71.35
	RM	60.16	63.8	60.16	60.16	78.49
	IM	59.32	61.77	59.32	59.32	63.30

- Same as above except imports from contracted coal facilities are not required (but are from owned coal facilties).
- Same as above plus imports of non-CEMS production from the Northwest are allowed to increase by 10% and credited with the Bonneville Power Authority average emissions rate of only 80 tons/GWh.

We simulate both a 15% and a 25% reduction in California utility power-sector emissions from 2007 baseline levels. In the case of a source-based regulation, this means a reduction from California utility sources from 41.17 mmTons to around 35 mmTons, or 30.9 mmTons, respectively. In the case of the first-deliverer scenarios, this implies a reduction from 108 mmTons (including the 41.17 from California sources) to a total of about 92 mmTons or 81 mmTons, respectively. The results for a 15% reduction are summarized in Table 6.

The most obvious and significant result is that none of the California regulations has much of an impact on WECC total emissions. The source-based California cap produces an allowance price of just under $13 a ton, but almost all of the 6 mmTon reduction in California is offset by increases in emissions in the other WECC regions. This is the standard leakage result. The first-deliverer regulations avoid this leakage, but compliance with the cap is possible through other mechanisms (discussed below) that

Table 7: Summary of Results with 25% Reduction in CO2

Outcome	Region	No Cap	Source Based Cap	First Del. 428 Default	First Del. 1000 Default	WECC wide cap
Permit Price		-	21.00	43.14	48.96	40.51
Emissions mmTons	Cal	41.17	30.88	36.64	35.84	39.40
	NW	118.78	123.48	120.24	120.60	116.56
	SW	107.89	111.55	108.77	109.59	86.43
	RM	63.07	63.74	63.06	63.08	61.52
	IM	15.74	15.74	14.97	15.74	15.74
	Total	346.65	345.39	343.68	344.85	319.65
Elec. Prices Avg. $/MWh)	Cal	61.63	69.35	86.2	82.91	83.08
	NW	68.32	80.2	73.43	74.15	91.34
	SW	54.93	57.22	53.95	55.94	74.83
	RM	60.16	65.89	61.89	63.08	81.82
	IM	59.32	62.27	59.96	61.23	63.36

require *no change* in production from any sources, and therefore produce a zero carbon price. The hypothetical WECC-wide cap, which by assumption would suffer no leakage, produces a "true" reduction of 16 mmTons, with a resulting allowance price of $35.26.

When the reductions are forced to a higher level of 25% of the 2007 baseline, more significant changes emerge. (See Table 7.) The first-deliverer regulations now produce a non-zero allowance price and some reductions in output. The most stringent version of the first-deliverer regulation, assuming a default emissions rate of 1000 tons/KWh, produces the largest WECC-wide reductions, but this is still a relatively modest savings of around 2 mmTons from production stemming from a "reduction" of carbon associated with California consumption of around 27 mmTons. By contrast, a WECC-wide cap with a goal of 27 mmTons reduction would produce an allowance price of $40.51.

5.3 First-deliverer Policy Variants

It may at first seem striking that the application of the cap to imported power in California has such limited impact on regional emissions. In order to decompose the changes behind these results, we now turn to the matching of sources to consumption that is fundamental to the first-deliverer paradigm. Figure 3 summarizes the location of the consumption of the power associated with its production for the case of a 15% reduction in California consumption-based emissions. Under the assumption that default emissions are 428 tons/GWh, a substantial amount of the baseline coal energy (all that is not under contract) is imported as default energy, which is treated as if its emissions were quite a bit lower than their true values. When instead the default is increased to 1000 tons/GWh, it is no longer economic to import coal (or anything else) and claim the default rate. Imports are instead identified from specific sources, but those sources shift from coal in the baseline to combined cycle gas sources in the capped case.

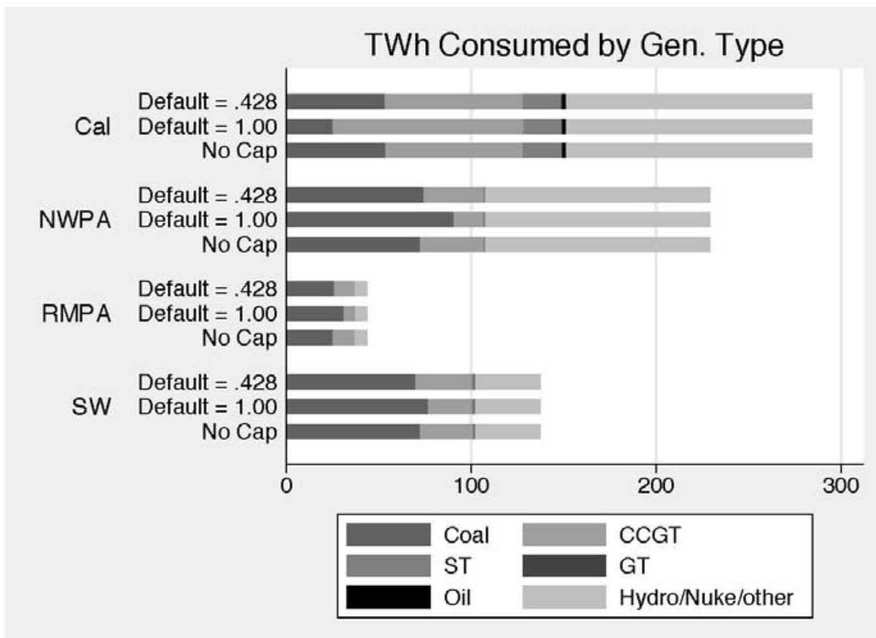

Figure 3: Consumption of Power with 15% reduction in CA Cap

The regulations have more impact when a 25% reduction is assumed for the power sector, as Figure 4 illustrates. Because the cap is binding, there is some reduction of generation from the dirtiest sources within California. The largest effects are still from imports being claimed under the default (see 428 default) and from reshuffling of sources when the default is set to 1000.

These results illustrate the nature of the problem of regulating consumption from ex-

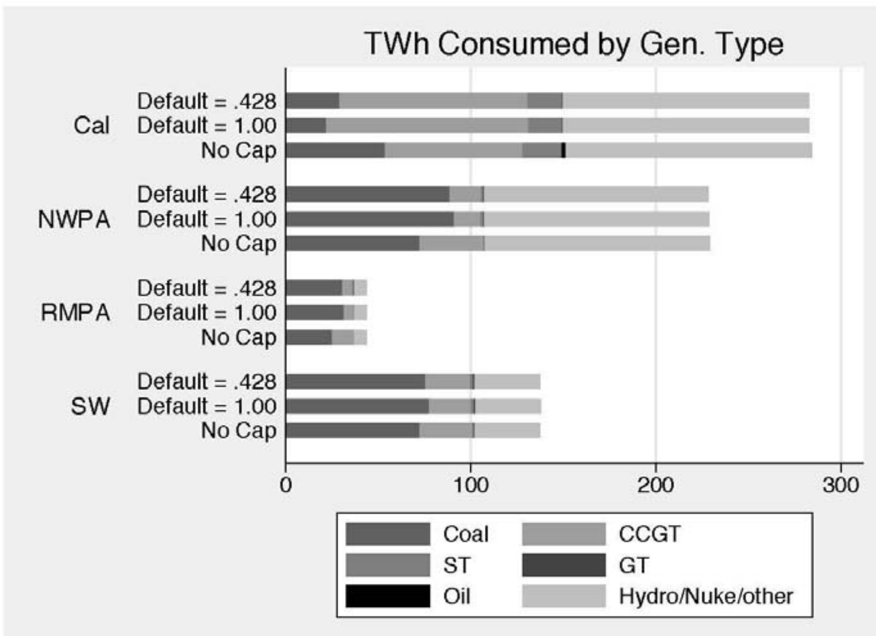

Figure 4: Consumption of Power with 25% reduction in CA Cap

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Table 8: "Excess" Emissions (mmTons) due to Default Emissions Factor.

Regulation	428	1000
Baseline	5.64	.19
No Contracts	7.84	.37
10% BPA Imports	21.19	1.04

ternal sources. There are two mechanisms for circumventing the spirit of this regulation. First firms can "launder" their imports by claiming the default rate for non-contracted sources. The extent to which this is possible depends upon how firmly other restrictions are enforced. The results above assume relatively strict enforcement of anti-reshuffling rules. Namely, it is assumed that firms cannot claim default values for imports from coal sources owned by or under contract to serve LSEs in California, and that no additional imports from non-CEMS sources are possible. As we relax the assumptions about these restrictions, the amount of power that can be claimed under the default increases. Table 8 illustrates this phenomenon for the case of a 25% reduction of the California cap. This table summarizes the total amount of apparent emissions savings from sources "consumed" in California but originating from external sources that can take advantage of the default rate (e.g., non-contracted sources). Under strict enforcement of existing contracts, emissions from imports are roughly 6 mmTons higher than they appear on paper due to lower default emissions rates. As the amount of external power eligible for the default rate increases, so do the savings from doing so. When all contracted coal plants are "abandoned" as sources - and are assumed to instead sell generic power - the savings from a 428 tons/GWh default rises to just under 8 mmTons.

Claiming power under a relatively clean "default" rate is only one mechanism through which compliance can yield little true emissions reductions. We now focus on a more strict default rate of 1000 tons/GWh. In this more strict case, the enforcement of the additional rules becomes significant. In general, even a modest relaxation of either the coal or existing hydro contract provisions has a strong influence on the impact of the cap. As the requirement to import from contracted coal plants is relaxed, permit prices under the 25% reduction case drop from \$48/ton to under \$21/ton. As Figure 5 illustrates, this is due to the reduction in coal imports into California. When imports from non-CEMS (e.g., hydro) resources are allowed to increase from the baseline by up to 10%, the price drops to zero. As seen in Figure 5, the amount of non-CEMS energy consumed in California increases under this scenario, and the amount of non-CEMS energy consumed in the Northwest decreases. Imports of combined cycle gas, with emissions around .45 tons/MWh, are being exchanged for imports rated at .08 tons/MWh, the BPA default rate. This increase in BPA sourced imports, combined with a reduction of coal imports relative to the base case, allows for compliance with a consumption based cap in California without altering the physical dispatch of resources in the WECC as a whole.

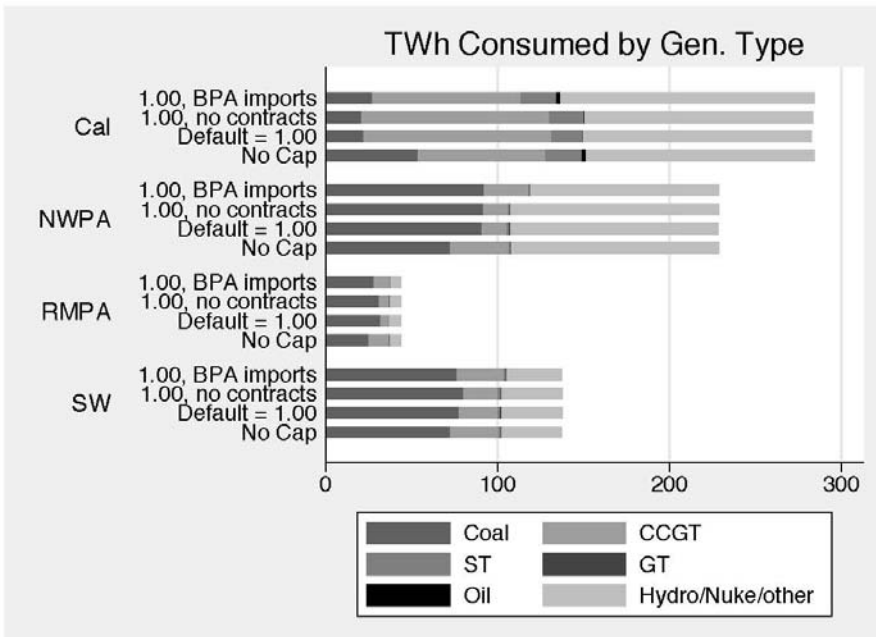

Figure 5: Enforcement of Anti-Shuffling Provisions

6 Conclusion

In this paper we analyze the impact of various forms of restrictions on greenhouse gases related to Californias electricity consumption. We formulate a baseline electricity market based upon 2007 operations in the Western Electricity Coordinating Council (WECC) region. We then simulate the impacts of placing a limit (or cap) on the GHG emissions from plants either located inside California or producing power that, at least nominally, is serving California consumers.

From an environmental standpoint, the results are not encouraging. Our previous work and research performed by others had indicated a strong vulnerability to leakage under a conventional source-based regulatory system. The simulations here are consistent with those findings. Capping California sources reduces emissions within the state, but also leads to increased imports and therefore emissions from outside California. It was a fear of such an outcome that motivated the first-deliverer design. The rules associated with such an approach are necessarily complex and a wide variety of options exist. We study several of the most likely variants of the first-deliverer system and find that, at least for reduction goals of 15% to 20%, they are unlikely to be more effective than a source-based system.

There is widespread opportunity for two mechanisms to undermine the effectiveness of a first-deliverer approach. The first mechanism allows firms to import power as "generic" power that is assigned a default emissions rate. The level of this default rate will determine the incentive to claim power as generic or as originating from a specific source. When the default rate is set, as is currently the case, at the relatively low level of .428 tons/MWh, there is a strong incentive for importers to claim any power dirtier than that default as generic. There is large scope for this activity, enough to easily comply with a goal of 15% emissions reductions without actually changing either the sources or destinations of power. The only change is the relabeling of imported power to unspecified, and the concurrent reduction in emissions associated with that relabeling. With a more aggressive reduction target of 25% simply relabeling existing imports is insufficient to meet the cap goals, and further adjustments to production become necessary.

When the default level is instead set at a more conservative 1 ton/MWh, (roughly that of an efficient coal plant) the incentive to claim imports as generic is largely eliminated. There is little advantage to relabeling imports. This does create an incentive for firms to exploit a second mechanism, however, reshuffling. The full extent of reshuffling will depend also upon several "soft" factors, including any impact of enforcement of CARB's prohibition included in the cap-and-trade reporting requirements, as described above. Other soft factors that might reduce reshuffling include the reluctance of non-California utilities to be seen as increasing their carbon footprint by taking on power abandoned by California buyers.

Because the effectiveness of the prohibition is somewhat uncertain, we consider several scenarios meant to represent varying degrees of prohibition. One scenario would prevent firms from claiming imports from existing hydro or renewable resources. Another scenario would require that firms currently with ownership or contract stakes in operating coal facilities to continue to be responsible for their proportional share of the emissions from those facilities, whether they nominally buy power from those plants or not. This amounts to a requirement to continue buying power from plants under contract or owned by a California LSE.

When the prohibition is applied as envisioned, and reshuffling is fully eliminated, the first-deliverer rules do result in some relatively modest real reductions in WECC-wide emissions. For example, under an assumed 1 ton/MWh default emissions rate and a cap that requires California electric sector emissions to be reduced by 25%, emissions allowance prices reach 48$ per ton. Reductions from the WECC overall are about 3 mmTons, however, only about 10% of the nominal 27 mmTon reduction required by the cap.

While we have tried to capture the most plausible outcomes from the prohibition on reshuffling, this language is deliberately not specific, and it remains to be seen what particular actions will constitute resource reshuffling under such rules. As such, we believe it is important to represent the incentives to reshuffle, and to consider the scenario in which resources are reshuffled, if for no other reason than to weigh the economic pressures that such restrictions will be pushing against.

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Notes

[1]Ironically, policy makers are often attracted to consumer-based regulations either because much of the production takes place outside of their jurisdiction or because they fear that regulating only producers within their jurisdiction will lead to leakage.

[2]WCI, 2008.

[3]In the 2008 CARB Inventory unspecified imports are assigned a default emission factor equivalent to US EPAs annual non-baseload output emissions rates for the Northwest (1201 lbs/MWh) or Southwest (1334 lbs/MWh) eGRID regions, depending on where the power entered California. These emission factors, which were reported in 2007 for the 2005 measurement year, may be accessed at: http://cfpub.epa.gov/egridweb/ghg.cfm.

[4]Although the California market was notorious for its high degree of market power in the early part of this decade, competitiveness has dramatically improved in the years since the California crisis, while the vast majority of supply in the rest of the WECC remains regulated under traditional cost-of-service principles.

[5]When the market is modeled as perfectly competitive, as it is here, the results are relatively insensitive to the elasticity assumption, as price is set at the marginal cost of system production and the range of prices is relatively modest.

[6] It is important to recognize that our modeling approach not only assumes that existing zero-carbon sources will not change *how much* they produce but also *when* they produce it. An interesting question is whether a redistribution of hydro-electric power across time could lower CO2 emissions by enabling a better management of fossil generation sources. Such an analysis would require a co-optimization of hydro and thermal electric production and is beyond the scope of this paper.

[7] This approach to modeling unit availability is similar to Wolfram (1999) and Bushnell, Mansur and Saravia (2008).

[8] The final "node" in the network consists of the Intermountain power plant in Utah. This plant is connected to southern California by a high-capacity DC line, and is often considered to be electrically part of California. However under some regulatory scenarios, it would not in fact be part of California for GHG purposes, it is represented as a separate location that connects directly to California.

Response: No changes were made in the 15-day amendments to any of the resource shuffling provisions to which this comment refers. Therefore this comment in its entirety is outside of the scope of the 15-day modifications, and does not require a response. As was mentioned by the Board and consistent with all ARB oversight of its regulations, staff will continue to monitor potential resource shuffling activities to ensure these provisions are enforced. The portions of this comment that address environmental consequences were addressed in the response to environmental comments on the proposed amendments, provided in Attachment A to this FSOR.

Safe Harbors, General

E-2.6. Comment: My name is Danny Cullenward. I'm a Research Fellow at the University of California Berkeley. I'm here today in my personal capacity.

Once again, I'm here, however, to ask the Board to not undermine California's carbon market with this expansive and unjustified reliance on safe harbors in its approach to regulating resource shuffling. There is no question that the Board's proposal formally and effectively eliminates the prohibition on resource shuffling through the safe harbor. By removing the only legal barrier to resource shuffling, the proposal threatens the environmental and economic integrity of the entire carbon market. (CULLENWARD 4)

Response: Adding safe harbor provisions to the resource shuffling provisions do not eliminate the prohibition on resource shuffling, as is clearly stated in section 95852(b)(2) of the Regulation. New section 95852(b)(2)(B) specifically prohibits resource shuffling in transactions involving electricity to which California utilities are entitled under long term contract or ownership arrangements with out-of-state coal facilities that are not compliant with the EPS. The legal barrier remains and will be strictly enforced by ARB.

The addition of safe harbors to the resource shuffling provisions is necessary for ensuring reliable electricity supply and to harmonize the Cap-and-Trade Regulation with other state and federal laws and regulations that are binding on the activities of electricity importers. The safe harbor provisions specify which activities are not considered resource shuffling, including: changes in electricity deliveries that are required by law or regulation, electricity needed due to emergency situations, or electricity needed because an electricity deliverer has more than enough electricity to meet demand, and therefore, must reduce electricity delivered from some of the resources to which it has rights. Other safe harbors cover situations over which an electricity deliverer has no control, and most deliveries resulting from short term transactions such as those involved in CAISO's energy markets which are generally entered into without knowledge of the generation resource that will be tapped to supply the need.

Leakage

E-2.7. Comment: Your own economic advisors and I have repeatedly warned you about the risks of this decision. Indeed, three major transactions have already occurred, causing between 30 and 60 million tons of carbon dioxide to leave to neighboring states. You already have these arguments in the analysis before you in written comments, so I won't repeat them here.

But I will say I'm deeply disappointed. Over the last year I worked to develop feasible solutions to the resource shuffling problem. All the while, I've recognized the utilities legitimate interest in clarifying the complexities of the original rule. Never the less, neither the Board nor any industry stakeholder has indicated a willingness to confront the environmental trade-offs in this politically expedient by substantially flawed decision. It is also surprising that everyone has been silent about this, because the issue is very well understood behind closed doors and among stakeholders. Before submitting my most recent comment letter, for example, I raised the issue that I'm bringing with you today with several colleagues and academia and in think tanks. Several of them asked me not to say anything publicly about the three transactions that have already occurred and their relationship to the safe harbor policy the Board is enacting. A few even warned me by raising the issues I could de-stabilize the political coalition that is necessary to maintaining California climate policy. This is a delegate deal these friends told me and a necessary imperfection.

I appreciate the Board faces enormous political resistance from industry and other political constituencies, including several environmental groups who are willing to reduce costs by any means necessary in this market. Never the less, the political compromise on resource shuffling represents a failure to take climate policy seriously. But if the outcome is disappointing, the process has been even worse. After more than a year of discussion, the Board has not publicly contemplated the leakage implications of safe harbors, let alone considered alternative approaches. That failure is all the more significant given that the investor-owned utilities are the ones who wrote the safe harbors in late 2012. Even today, the staff response to my written comments relies on legalese to avoid admitting what all major stakeholders and market participants know to be true, that the safe harbors allow electricity importers to resource shuffle. We can do better. And if we are going to take climate policy seriously, we have to. (CULLENWARD 4)

> **Response:** Economists have estimated potential worst-case scenarios of leakage that could possibly occur absent effective resource shuffling prohibitions. However, economic models used to estimate theoretical possible leakage do not account for the interaction of the Cap-and-Trade Regulation with federal criteria pollutant regulations that are causing coal electricity generation units to be retired as uneconomic throughout the United States, and including units in power plants under contract to California utilities. Experience to date indicates that the combination of California's Cap-and-Trade Regulation, other state regulations including the EPS and the RPS, the federal regional haze rules, and other states' laws are working together to force the retirement of coal power plants, resulting in real and additional reductions in GHG emissions.

The regulation, as amended, focuses the resource shuffling prohibition most directly on California utility entitlements to out-of-state coal power because this is the biggest potential source of leakage. More than three major transactions have occurred that involve changes in ownership of high emission coal power plant shares in the west, but they have not caused “between 30 and 60 million tons of carbon dioxide to leave to neighboring states.” Staff has looked into each of these cases and found that no resource shuffling with respect to these facilities has been observed to date.

ARB developed the current approach to resource shuffling after thorough discussion with federal and state regulators, electricity importers and utilities, other interested parties, and the Emissions Market Assessment Committee, to minimize leakage to the extent feasible, as required by AB 32. It would not be feasible to address resource shuffling as if electricity importers had no other obligations under federal and state law. ARB staff’s approach ensures the continued reliability of the western electricity system, and recognizes that the Cap-and-Trade Program must operate in concert with other regulations, programs, and policies. ARB intends to monitor electricity markets and imports, and to enforce the resource shuffling provisions.

F. OFFSETS AND OFFSET PROGRAM IMPLEMENTATION

F-1. Offset Program Implementation

Authorized Project Designee (APD) Requirements

F-1.1. Comment: Section 95974(a)(2) is amended to read: “The Offset Project Operator may delegate responsibility to the Authorized Project Designee for performing or meeting all the requirements of sections 95975, 95976, 95977, 95977.1, 95977.2, 95980, 95980.1, 95981, 95981.1, 95983, and, where the APD is specifically identified, the requirements in sections 95983, 95985, and 95990, where specifically identified on behalf of the Offset Project Operator.

- For clarity, we recommend amending this to read “and, optionally and in addition, where the APD is specifically identified, the requirements in sections 95983, 95985, and 95990.”
- This clarification makes it clearer that OPOs and APDs can contractually decide on a case by case basis as to whether the APD is accepting liability for reversal and invalidation risk.
- If ARB only allows OPOs to designate APDs if the APDs also accept liability for reversals and invalidation (which are in the case of forestry more in the control of the OPO than the APD), there may be very few APDs, increasing the number of regular interactions by ARB and the OPRs with first-time or one-time OPOs developing their first or only project. (NEWFORESTS)

Response: This portion of section 95974(a)(2) was not amended during the 15-day changes, so this comment is outside the scope of the 15-day changes.

Issuance of ARB Offset Credits

F-1.2. Comment: 4. Section 95981(c) specifies the following: “ARB will determine whether the GHG emission reductions and GHG removal enhancements meet the requirements of section 95981(a), the information submitted in sections 95981(b) and (c) is complete, and the Positive Offset or Qualified Positive Offset Verification Statement meet the requirements of sections 95977, 95977.1, and 95977.2 within 45 calendar days of receiving ~~it~~complete and accurate information.” In order to avoid significant delays in the credit generation process, we recommend a requirement for ARB to notify the OPO of incomplete or inaccurate information within a 10 calendar day period of receiving the initial project documents. (EOS)

Response: ARB staff requires longer than 10 days to review and assess the verification documents and all related materials, which is why there is a 45 day requirement for review. As such, ARB staff declines to make this change.

F-1.3. Comment: 5. Section 95981.1(d)(2) states that the OPO or verification body must submit requested information within 10 calendar days of ARB’s request. EOS appreciates the intent to streamline the approval process, however, 10 days would be insufficient in certain circumstances. For example, the lead verifier involved could be unavailable (e.g. conducting other verifications, on a site visit for another client, or on vacation for several weeks) or additional data may be required from third-party agencies that are not required to respond within 10 days. We suggest increasing the deadline to 90 calendar days. (EOS)

> **Response:** Section 95981.1(d)(2) was not amended during the 15-day changes, so this comment is outside the scope of the 15-day changes.

F-1.4. Comment: 6. Section 95981.1(f) The regulation states that ARB will transfer ARBOCs into the holding account of the OPO within 15 working days of the notice of determination. In order to keep the ARB timeline consistent with the issuance, notice of determination, and reduced invalidation timelines, and to reduce confusion, EOS proposes that the transfer should commence within 15 calendar days. (EOS)

> **Response:** Section 95981.1(f) was not amended during the 15-day changes, so this comment is outside the scope of the 15-day changes.

Buyer Liability Provisions

F-1.5. Comment: Offsets – Forestry Offset Liability
As we noted in our previous comments, WSPA remains concerned that the date of issuance of July 1, 2014 for forestry offsets is too soon to allow for processing of forestry offsets purchased prior to the regulatory changes.

Recommendation: WSPA recommends that the July 1, 2014 deadline for issuance for the new liability regime be revised to January 1, 2015. It would allow ARB more time to issue the ARBOCs from projects currently in the pipeline for issuance, and that have already come into contract under specific conditions. (WSPA 5)

> **Response:** The proposed date of issuance by July 1, 2014 will ensure that the proposed shift in liability occurs as soon as possible to ensure the environmental integrity of the program. As such, ARB staff declines to make this change.

New Offset Protocols and Offset Usage Restrictions

F-1.6. Comment: WSPA strongly supports the adoption of the new protocols for Coal Mine Methane. We support ARB's efforts to improve the use of offsets as a means to control cost of compliance. We note, however, that in the recent release of the Update to the Scoping Plan, ARB acknowledges that offsets are insufficient to meet the 2013-2020 maximum offset demand if every entity chose to use the maximum number of allowable offsets. (P.93). We also note, in the same document, ARB has acknowledged that California's stringent regulatory requirements limit the potential for generating in-state offsets. (WSPA 5)

> **Response:** To the extent the commenter is referring to future offsets rulemakings, the comment is outside the scope of this rulemaking. However,

ARB staff appreciates the commenter's support for the adoption of the Mine Methane Protocol. ARB has estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has adopted—livestock digesters, forestry, urban forestry, and destruction of ozone depleting substances, and the newly adopted mine methane capture protocol—ARB will have enough offsets in the program to the supply demand for the first compliance period. ARB is committed to evaluating additional offset types to ensure sufficient offset supply.

F-1.7. Comment: S95854: WSPA continues to oppose the 8% limit on use of offsets to meet a compliance obligation as this could limit the development and implementation of cost-effective GHG projects. We recommend instead that ARB remove the 8% limit on use of offsets so the offset market accurately reflects the relative abundance (or scarcity) of offsets. We encourage ARB to continue working with C/T stakeholders to develop additional, viable offset protocols to facilitate C/T program compliance and to help contain costs that would otherwise be incurred by regulated entities. (WSPA 5)

Response: This comment is outside the scope of this rulemaking. ARB did not make any changes to the 8 percent offset quantitative usage limit. The program imposes a limit on the number of offsets that an individual covered entity can use for compliance. All offsets used for compliance are real reductions, albeit outside the cap. Allowing a limited number of offsets into the program provides cost-containment benefits while still ensuring that GHG emissions reductions occur within the sectors covered by the cap-and-trade program. This limit will be enforced through a limit on the use of offsets by an individual entity equal to eight percent of its compliance obligation per compliance period. Combined with the Allowance Price Containment Reserve, this limit ensures that a majority of reductions from the program come from sources covered by the program at expected allowance prices, while use of the reserve will relax that constraint if prices rise.

General Comments About Offsets

F-1.8. Multiple Comments: 1. Section 95973(b) – Regulatory Compliance:
EOS supports the proposed language clarifying that offset projects must demonstrate compliance with regulatory requirements directly applicable to the offset project during the Reporting Period. However, as currently proposed, the Regulation does not define the start of offset project activities. This creates a number of potential uncertainties for project developers, verifiers, and ARB. For Ozone Depleting Substances (ODS) projects, EOS believes that point of origin determines the start of the chain of custody requirements and eligibility of the material, however, it does not always define the start of project activities undertaken by the Offset Project operator. There is an active refrigerant aftermarket in the U.S. such that ODS may have been recovered, transferred, and transported prior to, and independent of, destruction project activities. Since ODS material can be resold to this aftermarket, ARB should define project

activities as when the Offset Project Operator (OPO) takes control of the movement of refrigerant or title to the ODS for a project, which should also be the point in time that regulatory compliance becomes relevant.

Furthermore, Section 95973(b) does not define how credits will be issued if a compliance violation was recorded for a limited time within a longer Reporting Period. There may be cases of non-compliance that do not span an entire Reporting Period and the instance of non-compliance has no impact on the other activities during the Reporting Period. We suggest that ARB explicitly state that it will retain the discretion to withhold issuance of offset credits for specific times of non-compliance and amend the language as follows:

"If an offset project is not in compliance with regulatory requirements directly applicable to the offset project during a portion of the Reporting Period, the Offset Project Operator should be able to subtract any emission reductions that were generated during the time of non-compliance from the project's total emission reductions. ARB will issue offset credits only for the activities completed during the Reporting Period when the project was in compliance." (EOS)

Comment: 7. REQUIREMENTS FOR OFFSET PROJECTS & VERIFICATION BODIES
A. Section 95973(b): Offset Project Regulatory Compliance

Section 95973(b) can be interpreted as treating an entire Reporting Period as ineligible for offset credits if there is any violation, even if the violation was recorded for a limited time within a longer Reporting Period. There may be cases of non-compliance that do not span an entire Reporting Period and the instance of non-compliance has no impact on the other activities during the Reporting Period. We suggest that ARB explicitly states that it will retain the discretion to not issue offset credits only for specific times of non-compliance and amend the language as follows:

"If the offset project is not in compliance with regulatory requirements directly applicable to the offset project during a part of the Reporting Period, the Offset Project Operator should be able to subtract any emission reductions that were generated during the time of non-compliance from the project's total emission reductions. ARB will issue offset credits only for the activities completed during the Reporting Period when the project was in compliance." (IETA 2)

> **Response:** The requirements in section 95973(b) are equally and consistently applied to all offset projects. Each Compliance Offset Protocol approved by the Board defines offset project activities for an offset project of that type. ARB staff has addressed how the regulatory compliance provisions in the Regulation and the Compliance Offset Protocol U.S. Ozone Depleting Substances Projects are applied to ODS projects. This guidance is posted on ARB's website.
> ARB staff declines to make the changes requested to specify that non-compliance would only affect crediting for a portion of the Reporting Period. If a project is out of compliance it may not be possible to know exactly when the

project became non-compliant. For the issuance of compliance offsets, it is not sufficient to consider the date on which the non-conformance was first recognized by the OPO or APD as the date from which to count non-conformance, as the project may have been out of conformance and gone unnoticed for some time.

F-1.9. Comment: Sections 95973(b) and 95985(c)(2). Recommendation: restore the pre-15 day amendment language to 95973(b) to create a clearly defined threshold for a breach of law that prevents offset issuance, and amend 95985(c)(2) to avoid a problematic inconsistency with 95973(b) that could place ARB in the situation of issuing an offset credit and then immediately invalidating it.

- Section 95973(b) The 45-day amendments added *"In addition, an offset project must also fulfil all local, regional, and national environmental and health and safety laws and regulations that apply based on the offset project location and that directly apply to the offset project, including as specified in a Compliance Offset Protocol. The project is in regulatory compliance if the project activities were not subject to enforcement action by a regulatory oversight body during the Reporting Period. An offset projects is not eligible to receive ARB or registry offset credits for GHG reductions or GHG removal enhancements for the entire Reporting Period if the offset project is not in compliance with regulatory requirements directly applicable to the offset project during the Reporting Period."*
    - This created a clear safe harbor rule, in which offset credits could be issued unless the offset project activity was in breach of directly applicable environmental, health or safety law or regulation that led to an enforcement action by a regulatory oversight body during the Reporting Period. However, the 15-day changes amended the second sentence to read "The project is *out* of regulatory compliance if the project activities were subject to enforcement action by a regulatory oversight body during the Reporting Period", which eliminates the safe harbor, as this new sentence will be read as simply enumerating one of many possible ways for offset projects to be out of regulatory compliance.
    - Without a safe harbor that clearly defines when a breach of a health/environmental/safety law or regulation is material enough and applicable enough to prevent offset issuance, ARB will find itself in the position of either (a) denying issuance of offsets for very minor or technical breaches of applicable laws and regulations that have no relation to the project activity and achieved carbon sequestration/emissions reduction; or (b) subjectively deciding on a case by case basis that minor or technical legal breaches should not be grounds for denying offset issuance, but without the support of any clear language in the regulation that would allow for such issuance. For example, if a logging subcontractor on a forest carbon project area is found by a regulatory agency to not be wearing a hardhat or other required safety equipment part of the workday, and this violates OSHA regulations, should offsets not be issued for the applicable reporting period? If a water board in California issues a letter to

a landowner requiring improvements to stream crossings on roads recently damaged by flood within a forest offset project area, should offsets not be issued for the applicable reporting period? There are many instances where regulatory agencies charged with overseeing compliance with health, environmental and safety regulations issue letters noting minor breaches and requiring a regulated entity to implement a remedial action, but without instituting any formal legal proceedings or fine or other enforcement action. Do such letters constitute a breach that prevents offset issuance? After the 15-day amendments, it would seem that such letters would prevent issuance. We recommend deleting the 15-day changes to "The project is in regulatory compliance if the project activities were not subject to enforcement action by a regulatory oversight body during the Reporting Period."

- 95985(c)(2). Regardless of whether the 15-day amendments to 95973(b) are retained or abandoned, the language is inconsistent with Section 95985(c)(2), which states that one ground for invalidation of offsets is if "the offset project activity and implementation of the offset project was not in accordance with all local, state, or national environmental and health and safety regulations during the Reporting Period for which the ARB offset credit was issued."
  - Section 95973(b), prior to the 15-day amendments, would not deny offset issuance unless there was a breach of an environmental, health, or safety law or regulation that applies based on the offset project location and directly applies to the offset project and that leads to an enforcement action by a regulatory oversight body. After the 15-day amendments, Section 95973(b) would not deny offset issuance unless there was a breach of such a law or regulation that apply based on the offset project location and directly apply to the offset project.
  - However, Section 95985(c)(2) as drafted is grounds for invalidating an offset if the offset project activity was not in accordance with all local, state, or national environmental and health and safety regulations, regardless of whether they apply based on the offset project location, regardless of whether they directly apply to the offset project, and regardless of whether they lead to an enforcement action by a regulatory oversight body.
  - Thus, if ARB lets the existing inconsistencies stand between 95973(b) and 95985(c)(2), ARB could find itself in the position of being required by the regulation to allow the issuance of an offset and then immediately invalidate it. For example, an offset project could be in breach of an environmental or safety law that does not directly apply to the offset project: 95973(b) would allow the issuance of an offset in this situation but 95985(c)(2) would require that offset to be invalidated. Under the pre-15 day language of 95973(b), an offset project could be in technical/minor breach of an environmental or safety law, but not subject to an enforcement action by a regulatory agency: the pre-15 day 95973(b) language would have allowed the issuance of an offset in such a situation, while 95985(c)(2) would require invalidation in the same situation.

- **Therefore, in light of the 15-day and 45-day changes to 95973(b), we recommend that 95985(c)(2) be amended to read *"the offset project activity and implementation of the offset project was not in accordance with all local, state, or national environmental and health and safety <u>laws and</u> regulations <u>that apply based on the offset project location and that directly apply to the offset project</u> during the Reporting Period for which the ARB offset credit was issued. <u>The project shall be deemed in compliance with such environmental and health and safety laws and regulations if the project activities were not subject to enforcement action by a regulatory oversight body during the Reporting Period.</u>*** (NEW FORESTS)

Response: Regulatory conformance is intended to be limited to project activities. ARB cannot apply the term "material" in this situation as there is no way to clearly define what that term means. ARB staff believes section 95985 gives ARB sufficient authority to determine invalidation of ARB offset credits to ensure the environmental integrity of the program. This section does not place additional requirements on an offset project, but only ensures that all offset credits issued meet the requirements of the regulation and protocol. The determination to invalidate ARB offset credits will be based on new information not known to ARB at the time of issuance of ARB offset credits, and would be assessed against the issuance requirements. If the new information provided leads ARB to believe that the ARB offset credits meet the requirements for issuance, ARB would determine invalidation of the offset credits is not necessary; therefore, ARB does not agree that the provisions in 95973 and 95985 are inconsistent with each other. ARB staff will continue to work with OPOs, APDs, and offset verifiers to ensure successful implementation of these requirements, including through existing clarifying guidance.

F-1.10. Comment: 2. Sections 95975(g), 95977.1(b)(1), and 95979(f)(1) all propose that ARB has 30 calendar days to review each of the following forms: Project Listing, Notice for Offset Verification Services (NOV), and Conflict of Interest (COI). EOS believes that this 30-day review period per form is excessive and will unnecessarily impair their ability to efficiently complete projects and deliver credits to meet market demand. We recommend that the current 10-day timeline be retained for the NOV and COI forms. (EOS)

Response: The 30 calendar day timeframes for OPR and ARB review of listing information, Notice of Offset Verification Services (NOVS), and Conflict of Interest self-evaluations are necessary to ensure that the OPR and ARB staff have sufficient time to evaluate whether the eligibility requirements of the regulation are met and to ensure that there are no conflicts between verification bodies and verifiers and OPOs and APDs. Requiring the NOVS to be submitted at least 30 days prior to starting services is also needed to ensure that the OPR and ARB have sufficient time to plan audit and oversight activities.

The review of the NOVS and COI self-evaluation is not sequential and it is possible to submit the COI and NOVS simultaneously to shorten the timeframe. Additionally, 30 days is the maximum time allowed; it is likely that ARB or the OPR would complete their review in a shorter timeframe.

F-1.11. Multiple Comments: 3. Section 95977.1(a)(1) specifies that after the verification of six consecutive projects, an OPO must complete three full verifications with a second verifier prior to using the initial verification body again. EOS is supportive of the verification body rotation, however, the proposed rotation frequency will place significant pressure on a very limited number of verification bodies and will likely affect OPOs ability to complete projects within a reasonable timeframe. In addition, it is unclear on whether the proposed verifier rotation requirement would apply to an individual project starting with initial generation of "ARBOC(8)" credits (credits with 8-year invalidation risk) and extend to the conversion of ARBOC(8) to "ARBOC(3)" credits, which the market is demanding. We recommend that ARB clarify that the requirement for verification body rotation for generation of ARBOC(8) offsets and for conversion of ARBOC(8) credits to ARBOC(3) credits) are independent of one another. (EOS)

Comment: B. Section 95977.1(a)(1): Rotation of Verification Bodies for ODS Projects
Section 95977.1(a)(1) specifies that after six consecutive projects, project developers must use another verification body for a minimum of three projects. However, the Offset Project Operator (OPO) can only use the previous verification body once verification services have been completed for the three projects. IETA supports enforced rotation, however, for Ozone Depleting Substance (ODS) projects, the proposed rotation frequency is not practical given the limited number of approved verification bodies and will limit the ability of project developers to generate offset credits. IETA recommends that at minimum, ARB clarify that for ODS projects, the requirement for verification body rotation for generation of ARBOC(8) offsets (credits with 8-year invalidation risk) and for conversion of ARBOC(8) credits to ARBOC(3) credits are independent of one another. (IETA 2)

Response: ARB believes there are enough ARB-accredited verification bodies and verifiers to meet the demand for verifying ODS projects. For clarification on the second part of the comment, these rotation requirements are meant to cover both the verification activities for the issuance of ARB offset credits and any verification activities for reducing the invalidation timeframe of already issued ARB offset credits. ARB staff does not agree that the requirements for rotation should not apply in the same way to all verification activities for relationships between OPOs and APDs and verification bodies and offset verifiers. As such, ARB staff declines to make the suggested changes.

F-1.12. Comment: Section 95977.1(a) has been amended to read *"An Offset Project Operator or Authorized Project Designee may contract with a previous verification body or offset verification team member(s) only if at least three consecutive Reporting Periods have been verified by a different verification body or offset verification team* *member(s) before the previous verification body or offset verification team member(s) is selected again".*

- In the forest carbon context, one could conceivably contract with verifier X for verification in year 1 and 2 of a project, and then with verifier Y to truncate the invalidation period to 3 years. Under this language the OPO/APD would not be able to contract with verifier X again until the project had been verified for at least three consecutive reporting periods by verifier Y, even though verifier X has only verified the project twice.
- **We recommend amending the language in Section 95977.1.(a) to make clear that the rotation requirement only applies to situations in which an OPO/APD has previously contracted with a verification body for 6 consecutive Reporting Periods.** The language could be modified as follows (changes in bold):
  - An offset project shall not have more than six consecutive Reporting Periods verified by the same verification body or offset verification team member(s), unless otherwise specified in section 95977.1(a)(1) or (a)(2). An Offset Project Operator or Authorized Project Designee may contract with a **(delete: previous)** verification body or offset verification team member(s) **(add: with which they have previously contracted for six consecutive Reporting Periods)** only if at least three consecutive Reporting Periods have been verified by a different verification body or offset verification team member(s) before the **(delete: previous)** verification body or offset verification team member(s) **(add: with which they have previously contracted for six consecutive Reporting Periods)** is selected again, unless otherwise specified in section 95977.1(a)(1) or (a)(2). (NEW FORESTS)

Response: ARB staff declines to make this change. The Regulation requires that a different verification body verify a subsequent Offset Project Data Report within 3 years to reduce the invalidation timeframe. This is needed to ensure that the invalidation timeframe should be reduced. Reducing the invalidation timeframe is optional. If an OPO or APD chooses to reduce the invalidation timeframe, it must meet these requirements, including rotating its verification body.

F-1.13. Comment: 7. Given that Sections 95985 and 95990 are silent on timelines for completion of desk reviews and invalidation verifications, it would benefit OPOs and ARB to define timelines for reviewing the submitted desk reviews for Early Action Offset Projects and submitted reduced invalidation project verifications. While timelines are defined for the registries and direct to ARBOC project generation, EOS recommends that timelines be defined in the regulations. In the absence of regulatory timelines, early action projects approvals have taken in excess of 6 months from time of submission, resulting in major disruptions to OPO operations, finances, and market participation. For example, in Section 95985(b)(1)(A)(2)(d), we suggest the following addition in italics:

"The Offset Project Registry has an additional 15 *calendar* days to submit its report to ARB. ARB will review the Offset Project Registry report and, *within 45 calendar days,* determine based on the authorized Project Designee, if applicable, if the invalidation timeframe will be reduced. During its review, ARB may request additional information, *clarifications*, and revisions to the materials, if necessary."
Similarly, in Section 95990(f)(3)(F), we suggest the following addition in italics:
"ARB will review the desk review findings submitted by the desk review verification body *and within 45 calendar days notify the Offset Project Operator on its determination* whether to accept or reject the findings." (EOS)

> **Response:** ARB staff does not believe it necessary to explicitly limit the review time or notification time to 45 calendar days, and believes the language as proposed in the 15-day amendments is sufficiently clear to allow for additional information (including clarifications) upon request. As such, ARB staff declines to make the suggested changes to section 95985(b)(1)(A)(2)(d) and section 95990(f)(3)(F),

F-1.14. Multiple comments: Section 95978(e): Direct supervision," for purposes of this section, means daily, on-site, close contact by the supervisor who is able to respond to the needs of the technical expert. The supervisor must be physically present, or within 4 hours travel time and available to respond to the needs of the technical expert.
It is the interest of the ARB-accreditor verifier (supervisor) to maintain close contact and supervise the technical expert; however, the above requirements are not necessary should other communication methods be diligently employed (e.g. daily communication and on an on-call basis via cell phone, satellite phone or skype). The definition of direct supervision requiring the supervisor to be physically present or within 4 hours travel time is infeasible for a site visit of more than one to two days. This requirement will unnecessarily increase verification costs for the forestry and rice protocols and require an ARB-accreditor verifier to be within an arbitrary proximity for an extended duration when the same supervision could be provided through the use of technology.
Technical experts are included on the verification team based on their expertise and specialization in a given field. The supervision of an ARB-accreditor verifier for matters related to verification activities can be accomplished through clear training and diligent communication from a location more than 4 hours away. Given the limited pool of ARB-accreditor verifiers and the number of verifications spread throughout the country, it would not be cost-effective to require an ARB- accreditor verifier to remain onsite or without 4 hours, rather the requirement should be for the supervisor to communicate daily with the technical expert to address any concerns from the technical expert or to supervise and provide guidance about their scope of work that may impact verification decisions.

Above all, SCS would like to reiterate that they have made a long-term investment in rigorous and high-quality verifications against the ARB Regulation. The recommendation that they are making about amending the onsite/4 hour direct supervision requirement would in no way reduce verification rigor. This comment is intended to increase efficiency and reduce costs for OPOs/APDs, and not reduce the rigor of verifications that are subject to regulatory review and invalidation. (SCS)

Comment: Section 95978(e). The 15-day changes define direct supervision of technical experts to mean an accredited verifier's physical presence or availability within four hours of travel time. In the forest carbon context, technical experts are employed by verifiers to conduct data checks on forest inventory. The data checks in sequential sampling can require weeks of time. There are not many accredited verifiers at this time.

- Requiring an accredited verifier to remain within four hours of a technical expert conducting a sequential sampling data check is: (a) unnecessary, as technical experts are employed in the forest carbon due to their expertise in field forest inventory techniques, are trained by accredited verifiers according to clear criteria, and can take photos or video of any unusual situation to send to an accredited verifier for decisions; (b) expensive, and will drive up verification costs significantly with no similar improvement in accuracy; and (c) personally problematic for accredited verifiers of forest projects – as more forest projects enter verification, they could conceivably be required to spend much of the year in motels within four hours of an active sequential sampling data check.
- **We recommend amending this language to require accredited verifiers to be available within one hour via telecommunications to address any questions raised by the technical expert. In the forest carbon context, technical experts could then carry cell or satellite phones and send photos or videos to accredited verifiers from the field with questions. Verifiers could respond immediately. Direct supervision would be maintained without requiring accredited verifiers to remain within four hours of a technical expert who may be spending weeks in a remote area working on a data check.** (NEW FORESTS)

  Response: ARB staff declines to make this change. Technical experts are allowed to assist with verification and should not be independently performing verification related tasks. ARB-accredited verifiers are responsible for the actions of technical experts during the verification and thus must be available to supervise. ARB staff feels that physical proximity of the ARB-accredited verifier is essential to maintain the integrity of the verification services.

F-1.15. Comment: <u>95985(b)(1)(A)(1):</u> "Has a different verification body that has not verified the Offset Project Data Report for the issuance of ARB offset credits, and meets the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a), that meets the requirements for conflict of interest conduct a second independent regulatory verification pursuant to sections 95977 through 95978, except for section 95977.1(b)(3)(M), for the same Offset Project Data Report, or as provided in sections 95990(l)(3)(B) and (l)(4) for projects developed under an approved early action quantification methodology."

While it is not stated in sections 95977 through 95978, please confirm that the Offset Verification Report, or other verification work products developed by the first verifier would not be required as a part of the second verifier's review. Our understanding of the Regulation is that the invalidation audit would be a second independent review of the OPDR. (SCS).

> **Response:** The comment is correct that the second audit is independent, as is stated in the provision quoted in the comment. Please see the underlined text in the provision as follows: "Has a different verification body that has not verified the Offset Project Data Report for the issuance of ARB offset credits, and meets the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a), that meets the requirements for conflict of interest conduct a second independent regulatory verification pursuant to sections 95977 through 95978, except for section 95977.1(b)(3)(M), for the same Offset Project Data Report, or as provided in sections 95990(l)(3)(B) and (l)(4) for projects developed under an approved early action quantification methodology."

F-1.16. Comment: Section 95977.1(b)(3)(M). We support the addition of the double underlined text that clarifies that "The offset verification team shall use professional judgment in the determination of correctable errors, including whether differences are not errors but result from truncation or rounding". This section also requires the OPO/APD to make "all possible improvements", however, and **we recommend that the above sentence be amended to state *"The offset verification team shall use professional judgment in the determination of possible improvements and correctable errors.***

- A negative OVS should not be issued for uncorrected typos or grammatical errors or similar minor errors; the verifier should be able to use professional judgment to decide whether a change is really an improvement. (NEW FORESTS)

> **Response:** This provision, as amended in the 15-Day Modifications, is consistent with the requirements in MRR for fixing errors and making improvements. The reporting program and offset program both implement these requirements in the way the commenter describes, and additional clarification would not change the way the provision is implemented; therefore, ARB declines to make this change.

F-1.17. Comment: Finally, I would like to comment on two areas of the rule, which the staff talked about today, that are going to be evaluated later this year. In particular, the rice protocol, which is really a landmark achievement for California if and when we are able to achieve it, getting an agricultural sector, using models that are peer reviewed and verified for calculating emissions reductions. This is something that California really can set the pace and is setting the pace for regulatory achievements in the US. (EDF 3)

Response: This comment is outside the scope of this rulemaking. A rice cultivation protocol is not including in this rulemaking and any comments related to this protocol would be considered and addressed during the public process associated with the evaluation of that protocol and any future potential rulemaking to propose the addition of this protocol in the Cap-and-Trade Regulation.

G. COMPLIANCE OBLIGATION SURRENDER

G-1. General

G-1.1. Comment: Due to the extensive number of changes and new reporting requirements that may be required of entities subject to the Cap-and-Trade Regulation, many of which pertain to auction participation, ARB should clarify the effective date of the new regulation and clearly communicate to stakeholders which auction will be subject to the new requirements. Clarification of this information will provide covered entities and other market participants regulatory certainty and will facilitate compliance with the amended regulation. (CCEEB 2)

> **Response:** Thank you for the comment. With respect to the May 16, 2014 auction, that auction will occur prior to the amendments made as part of this rulemaking package taking effect. As such, existing Cap-and-Trade regulatory requirements (i.e., prior to these amendments being effective) will govern the requirements for that auction. Regulatory deadlines and requirements in effect prior to the effective date of these amendments will also apply until these amendments take effect (expected July 1, 2014). After July 1, 2014, the requirements as amended in this rulemaking will govern. Staff will continue to publicly post the dates and deadlines surrounding auction participation and will work to clearly communicate any changes to information pursuant to the proposed amendments. Please note that, to the extent auction participation rules or other requirements change, those changes will be effective for the next auction.

G-1.2. Comment: Given I have one more minute, I just wanted to suggest that the Board also in a future rulemaking please address the procurement and holding limits. Currently, that limit is arbitrary. It's too low for large emitters. And particularly with fuels coming under the cap in 2015, I think it poses an issue for large emitters to be able to procure enough allowances while providing the opportunity for smaller emitters to hoard those allowances. I ask that you look at the EMAC recommendations, which state that the holding and procurement limits should be set at an entity's net obligation. (SHELL 5)

> **Response:** These comments are outside the scope of the proposed 15-day changes to the Regulation, so no response is required. Staff will continue to evaluate the implementation of the program, including reviewing any future recommendations of the EMAC, when considering if future amendments are necessary.

Retirement for EDUs

G-1.3. Comment: LADWP supports the new language that clarifies that an electrical distribution utility (EDU) will not be in violation of §95892(d)(5) when the Executive Officer retires compliance instruments per its proposed surrender order as long as CARB and the EDU have the same resulting account balance. The new language addresses LADWP's concern that although the EDU's and CARB's accounting of the compliance account balance would be the same in terms of the number of allowances, the EDUs' accounting of allowances by vintage and date procured would not match CARB's because EDUs are prohibited from using the value of their allocated allowances to meet compliance obligations that do not benefit its retail ratepayers consistent with the goals of Assembly Bill 32. (LADWP 3)

Response: Thank you for the comment and support.

G-1.4. Comment: The 15-Day Changes include a significant and much needed change to the provisions regarding the treatment of allowances withdrawn from the compliance accounts of electrical distribution utilities (EDUs) for retirement to meet a compliance obligation. M-S-R appreciates the recognition that the methodology for withdrawal of allowances for retirement purposes could result in a violation of the provisions of 95892(d)(5), despite the fact that the EDU at issue has a sufficient number of eligible allowances to meet its compliance obligation. In order to address this concern, the 15-Day Changes would add 95856(h)(4) to the Regulation, which provides: "An electric distribution utility will not be in violation of section 95892(d)(5) when the Executive Officer retires compliance instruments, if the electric distribution utility has a sufficient quantity of eligible compliance instruments not allocated pursuant to section 95870(d) in its compliance account, at the time the timely surrender of compliance instruments by a covered entity is due pursuant to section 95856, that is at least equal to its compliance obligation for any transactions for which the use of allocated allowance value is prohibited under section 95892(d)(5)."

This language would avoid potentially forcing an EDU into violating the provisions of section 95892(d)(5), which places restrictions on the use of allocated allowances, and should be adopted. (MSR 2)

Response: Thank you for the comment.

G-1.5. Comment: NCPA supports the proposed addition of section 95856(h)(4) to the Regulation. The addition of section 95856(h)(4) addresses the concerns raised by POUs that CARB's predetermined order of allowance withdrawals could technically put EDUs that designated freely allocated allowances directly into their compliance accounts in contravention of the prohibitions on the use of allowance value set forth in section 95892.6 While the POUs had recommended creating rules that would allow covered entities to designate the order in which allowances would be retired, new 95856(h)(4) would address this concern by ensuring that POUs are not "forced" into a violation of the provision prohibiting the use of allowance value for sales into the ISO. New section 95856(h)(4), which provides: "An electric distribution utility will not be in violation of section 95892(d)(5) when the Executive Officer retires compliance instruments, if the electric distribution utility has a sufficient quantity of eligible compliance instruments not allocated pursuant to section 95870(d) in its compliance account, at the time the timely surrender of compliance instruments by a covered entity is due pursuant to section 95856, that is at least equal to its compliance obligation for any transactions for which the use of allocated allowance value is prohibited under section 95892(d)(5)." should be adopted for inclusion in the Regulation. (NCPA 3)

Response: Thank you for the support.

Timely Surrender of Compliance Instruments

G-1.6. Comment: Section 95856(f) requires covered entities to transfer sufficient compliance instruments to their compliance accounts by November 1, 5 p.m. Pacific Standard Time following the final year of the compliance period. CARB proposes new language stating that transfers to compliance accounts may be restricted during the time the tracking system is processing the surrender of the triennial compliance obligation. While freezing the compliance accounts while CARB conducts its reconciliation process would not be unlike what is current being done in the EPA Acid Rain Program, the Acid Rain Program does not have holding limits. Thus, freezing the compliance accounts could adversely impact entities that are near their holding limit and have no opportunity to transfer compliance instruments into their compliance account for a period of time, which CARB has not defined. LADWP recommends that CARB: 1) define the period of time that it will restrict entities' access to their compliance accounts; and/or 2) temporarily lift the holding limit requirement until the compliance account restriction is removed. (LADWP 3)

Response: While staff appreciates the concern expressed in the comment, staff believes there is sufficient flexibility in the system to prevent the difficulty described in the comment. Entities have three days to complete the transfer request process and can schedule their purchases and transfers to compliance accounts around the restrictions imposed by compliance settlement in the tracking system. Section 95856(f) is necessary to ensure that there is no movement of compliance instruments between entity accounts during settlement as the routines to process settlement need static compliance account balances. Staff believes entities have sufficient knowledge of the day and time that movement of compliance instruments into the compliance account will be restricted and are able to manage their holdings to not violate the holding limits. Therefore, ARB staff declines to make either change suggested by the commenter. Strictly enforcing holding limits near the time of compliance surrender is vital to ensure no entity has engaged in forward contracts to reduce instruments available for other market participants during this critical time.

G-1.7. Comment: And staff are working with the EDUs on properly recognizing the implications on the retirement order and ensuring that EDUs that are allowed to place compliance instruments into their compliance account directly are not somehow penalized by the order in which the allowances are retired. (NCPA 4)

Response: Thank you for the support.

G-1.8. Comment: SDG&E and SoCalGas have proposed the following minor clarification to Section 95856(g)(1)(A) for internal consistency:

Retire the compliance instruments surrendered <u>in accordance with section 95856(h);</u> and (SEMPRA 4)

Response: ARB staff does not agree that the proposed modification is necessary as it duplicates section 95856(g)(1) which includes the language "in the case of annual and triennial compliance obligations."

Delays in Surrender

G-1.9. Comment: SDG&E and SoCalGas have proposed a minor modification to Section 95856(d)(4) to ensure that restrictions on transfers to compliance accounts do not preclude entities from meeting the deadline for surrender of annual compliance obligations. The minor modification confirms that there will be no restrictions on transfers to compliance accounts during the last two business days before the deadline: Transfers to compliance accounts may be restricted during the time the tracking system is processing the surrender of the annual compliance obligation, except that there shall be no restrictions during the last two business days before each deadline for surrender of annual compliance obligations. (SEMPRA 4)

Response: Thank you for the comment. The intent of new section 95856(d)(4) is to make entities aware that after the compliance surrender deadline access to the tracking system may be restricted. This ensures that there is no movement of compliance instruments between entity accounts during the settlement of their compliance obligations. ARB staff does not agree that additional clarification is required as "processing the surrender" can only occur after the surrender has taken place.

Retirement Order

G-1.12. Comment: Due to the holding limit as currently written, a large final emitter (LFE) has significantly less flexibility to keep allowances in its holding account than other regulated entities, and often must store a significant number of allowances in its compliance account. Where smaller entities may hold onto allowances in their holding account right up until the compliance deadline, an LFE must keep allowances to cover its compliance obligation in its compliance account to navigate the holding limit. The pre-determined compliance unit retirement order that ARB proposes presents just another additional challenge to navigate for account representatives, who will face the additional challenge of balancing allowances and offsets in their compliance accounts. (IETA 2)

Response: ARB staff disagrees with several of the comment's assertions. First, all registered entities face the same maximum limit on the number of allowances they may have in their holding accounts. The limited exemption gives larger entities greater flexibility in holding allowances to meet their obligations because it allows larger entities to hold more instruments in their compliance accounts. The limited exemption also gives larger emitters greater flexibility when compared to smaller emitters because it covers some future as well as historical emissions. Second, the claim that smaller entities can more easily make the transfer to compliance accounts on time is mistaken. Entities have 11 months between the last auction of a compliance period and the deadline for compliance transfers. Staff believes entities will not have difficulty scheduling internal transfers over such a long period. Finally, if an entity has met its compliance obligation by placing the correct number of instruments in its compliance account, the retirement order provisions are irrelevant and should not pose any difficulty for the entity.

G-1.13. Comment: In previous rounds of stakeholder comments, IETA has provided detail on how the proposed automatic compliance unit surrender order may prove problematic in dealing with important accounting concerns. We repeat those concerns here.

Consider the U.S. Environmental Protection Agency's (EPA) Acid Rain Program in determining the importance of an entity's ability to choose which compliance units it retires in light of tax implications. In the Acid Rain Program, an entity has the option to choose to retire specific allowances based on their tax basis (this is often referred to as "specific identification" by the accountants).

For tax purposes the basis of a freely allocated allowance is usually zero. That contrasts with a purchased allowance, where for tax purposes the basis would be the purchase price. An entity can then choose to retire an allowance based on its tax basis. In the Acid Rain Program, since SO2 allowances are treated as a capital asset, a company could choose allowances based on how it would impact its capital gains posture for a given year.

According to a Journal of Accountancy report, approximately three quarters of companies value freely allocated allowances at zero, and purchased allowances at cost. With this in mind, entities may want to choose to retire compliance units in a different order than is proposed by ARB. Different entities will have different financial drivers depending on their industry, financial situation, accounting policy, etc. – so while one company may wish to retire freely allocated allowances first, another may wish to do the opposite. Similarly, one company may wish to retire earlier vintages first, and another may wish to retire later vintages first. Consider the following example: A company in California is expected to emit 100 tons of GHGs per year in 2013 and 2014, and ARB allocates 80 allowances/year for free (i.e. 80 vintage 2013 allowances and 80 vintage 2014 allowances) leaving a shortfall of 20 tons/year that must be bought in the marketplace.

Assume that this company is concerned about rising costs, so it buys 40 tons of vintage 2013 allowances (the most liquid contract) in the marketplace at $15/ton to hedge its price risk. The regulation allows the company to use vintage 2013 allowances for compliance with 2013 or 2014 emissions.

Assume, now, that for whatever reason (perhaps production was down), that company only actually emitted 90 tons in 2013 and 90 tons in 2014. This leaves it with 20 surplus allowances, which it banks for 2015.

The regulation says that ARB will retire allowances in a specific order, starting with the earliest vintages (i.e. all vintage 2013s will be retired first). So in the company's registry account, it is left with 20 vintage 2014 allowances. Since all of these were allocated for free, this would be valued at zero on the company's balance sheet.
However, depending on the company's inventory/accounting policy, that company may actually prefer to retire all freely allocated allowances first (including all vintage 2014s), leaving them with 20 vintage 2013 allowances instead (which they value at cost).

As this example points out, there are important accounting considerations that make it necessary that an entity has the option to choose its own compliance unit surrender order depending on different circumstances. IETA strongly encourages ARB to provide this capability within CITSS. (IETA 2)

> **Response:** This comment was originally submitted during the 45-day comment period, and the response provided to 45-day comments G-2.4 is reproduced here. ARB staff appreciates that the retirement order affects a covered entity's accounting. If an entity would prefer not to retire a compliance instrument, the account representatives may choose to keep it in the holding account, rather than submitting it for compliance. The goal of the retirement order is not to optimize an entity's tax exposure, but rather to minimize the compliance and administrative costs. Staff will monitor compliance during the surrender events to ensure an effective implementation of the retirement order process.

G-1.14. Comment: Section 95856 of the proposed amendments continues to specify an automatic compliance unit surrender order in which the Executive Officer retires compliance units from a compliance entity's account in both annual and triennial compliance years. While the September 2013 proposed amendments removed annual compliance surrender obligations, the proposed 15-day amendments re-instate those annual compliance obligations.

Regardless of whether there exists, or doesn't exist, an annual compliance surrender obligation, IETA would like to re-state for the record that individual entities should, themselves, be given the flexibility to indicate which compliance units they would like to surrender. We appreciate the need to provide a default surrender order in case an entity fails to indicate its own surrender order, but this default order should not supersede an entity's preference, if indicated. We understand that the Compliance Instrument Tracking System Service (CITSS) currently does not have the functionality to allow entities to indicate their own retirement order preference, but our membership contends that the benefits of implementing such functionality outweigh the cost. (IETA 2)

Response: ARB staff understands the concerns raised by stakeholders. However , as stated on page 35 in the Initial Statement of Reasons, available at http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf, the overall policy objectives of the retirement order include maximizing the use of offsets up to the limit to ensure maximum compliance flexibility at least cost, and removing compliance instruments in the order of least to most challenging to liquidate at auction if the tracking system account were to be closed for a particular entity. The first compliance instruments to be retired are the compliance offset credits up to the 8% entity limit. These compliance instruments are the lowest cost compliance instruments and, because there is no holding limit on offsets, an entity has no requirement or incentive to place more offsets in their compliance account than they want retired. Second, the Executive Officer would retire allowances purchased from the Allowance Price Containment Reserve (Reserve) or Quebec issued early reduction allowances. These allowance types do not have a vintage and would be challenging to liquidate at auction, if the account were to be closed. Since entities would only buy from the Allowance Price Containment Reserve as a last resort, it is unlikely the Reserve allowances would be purchased and used for compliance. Third, the Executive Officer would retire allowances in the order of earliest to latest vintage. Since allowances can be banked but not borrowed this assures that eligible vintage allowances are retired for compliance first. Lastly, the Executive Officer would retire a limited amount of future vintage allowances. The only time future vintage allowances would be eligible for compliance is when they are provided by ARB for allocation true-up. Clarifying changes to the retirement order in 15-day changes to specify the exact order for retiring instruments at the annual and triennial surrender deadlines ensure the policy objectives stated in the Initial Statement of Reasons are met, while still providing market flexibility.

Moreover, the design of CITSS does not currently support the ability of entity specification of compliance instrument retirement order. Staff therefore believes the amendments to specify the compliance order are necessary and declines to make the requested changes.

G-1.15. Comment: At the July 18, 2013 ARB Workshop, regulated entities expressed their opposition to the staff-proposed compliance instrument retirement order. To address these concerns, ARB staff suggested that they might allow covered entities to select which compliance instruments in their compliance account to retire prior to a compliance deadline. By allowing entities to self-select the compliance instruments they wish to retire, the ARB-proposed compliance instrument retirement order would only need to be exercised if a covered entity failed to select enough instruments to fulfill its compliance obligation. SCE supports this framework and urges the ARB to adopt such provisions in the Cap-and-Trade Regulation.

Retirement flexibility allows compliance entities to better manage their portfolios and reduces the administrative burden for the regulatory agency. By allowing covered entities to select compliance instruments for retirement, the ARB's regulations would also be in keeping with other environmental compliance trading programs, including the United States Environmental Protection Agency's Acid Rain Program and California's RPS program. (SCE 4)

> **Response:** ARB staff understands the concerns raised by stakeholders, however the compliance instrument retirement order specified in the Regulation will remain. Unlike other emissions trading programs, including EPA's Acid Rain Program, compliance instruments in the Cap-and-Trade Program do not have a serial number that is visible to covered entities, limiting the ability of entities to actually specify an order for compliance instrument retirement.
>
> Staff appreciates that the retirement order affects a covered entity's accounting. If an entity would prefer not to retire a compliance instrument, the account representatives may choose to keep it in the holding account, rather than submitting it for compliance. The goal of the retirement order is not to optimize an entity's tax exposure, but rather to minimize the compliance and administrative costs for both the entity and ARB. Staff will monitor compliance during the surrender events to ensure the retirement order process runs smoothly.

G-1.16. Comment: Under Section 95856(h)(4), the ARB will exempt utilities from the allowance retirement order for allowances other than those allocated by the ARB. TID continues to believe that there should be no mandated retirement order for the triennial compliance obligation, and that a retirement order will tend to result in higher compliance costs for covered entities. Covered entities are in the best position to determine how to meet their compliance obligation in the most cost effective manner. However, TID appreciates the flexibility the ARB will provide to utilities.
In addition, Section 95921(a)(4) would be revised to allow additional flexibility in conducting future allowance transactions. Specifically, the prohibition against future transactions would apply as of the "termination date" of the transaction agreement. TID supports this change and appreciates the ARB's receptiveness to TID and other parties' comments on this issue.(TID 3)

> **Response:** ARB staff appreciates that the retirement order affects a covered entity's accounting. If an entity would prefer not to retire a compliance instrument, the account representatives may choose to keep it in the holding account, rather than submitting it for compliance. The goal of the retirement order is not to optimize an entity's investment portfolio, but rather to minimize the compliance and administrative costs for both the entity and ARB. Staff will monitor compliance during the surrender events to ensure the retirement order process runs smoothly.
>
> In addition, thank you for the support for the modifications made to section 95921(a)(4).

G-1.17. Comment: If ARB is to implement the concept of an "Annual Allocation Holding Account", then we recommend section (c) be changed as follows:
"(c) A covered entity must transfer from its holding account or annual allocation holding account to its compliance account a sufficient number of valid compliance instruments to meet the compliance obligation set forth in sections 95853 and 95855."
WSPA recommends ARB eliminate this section. However, if ARB determines this section mandating the order of retirement is necessary, then there should be language added that gives companies the option of directing the order of retirement for the various types of compliance instruments. Towards this end, we recommend:
New Section 95856(h)(1)(E) to read: "Alternatively, a covered entity can specify the order of retirement of compliance instruments and their amounts by providing written instructions to the Executive Officer no later than October 15 of each compliance year, prior to the November 1 retirement date."

> **Recommendation:** New Section 95956(h)(2)(E) to read: "Alternatively, a covered entity can specify the order of retirement of compliance instruments and their amounts by providing written instructions to the Executive Officer no later than October 15 of the year following the compliance period, prior to the November 1 retirement date." (WSPA 5)
>
> **Response:** ARB staff understands the concerns raised by stakeholders, however the compliance instrument retirement order specified in the Regulation will remain. Staff does not agree with the proposed modification to section 95856(h)(1)(E) or the addition of section 95856(h)(2)(E) as compliance instruments in the Cap-and-Trade Program do not have a serial number that is visible to covered entities, preventing entities from fully ordering compliance instrument retirement. Staff appreciates that the retirement order affects a covered entity's accounting. If an entity would prefer not to retire a compliance instrument, the account representatives may choose to keep it in the holding account, rather than submitting it for compliance.
>
> In addition, submitting compliance instructions for each entity would place an undue administrative burden on staff and could result in inadvertent compliance violations were entities to incorrectly specify retirement order and quantity. The goal of the retirement order as specified in the regulation is to minimize the compliance and administrative costs for both the entity and ARB. Staff will monitor compliance during the surrender events to ensure the retirement order process runs smoothly.

Annual Offset Usage Limit

G-1.18. Comment: Section 95856(h)(1) has been modified to address the annual surrender obligation and provide an order in which instruments are to be retired. Subsection 95856(h)(1)(A) specifies that offset credits will be retired first, up to eight percent of the emissions with a compliance obligation pursuant to 95855. While SGEN believes that the application of the Quantitative Usage Limit ("Limit") is appropriate when ARB retires instruments from an entity's compliance account, the application of the Limit to the Annual Surrender, and Triennial Surrender as indicated at section 95856(h)(2), could lead to confusion.

Other relevant sections of the Regulations support the use of the 8% offset limit only in the context of the Triennial Compliance Obligation. For example, Section 95854(b) specifies that each covered entity may surrender, "to fulfill its compliance obligation for a compliance period, offsets to not exceed 8% of the total instruments surrendered, also known as the 'Quantitative Usage Limit'." Under the current definition of 'Compliance Period,' at section 95802(a)(56), this is the three-year period for which the compliance obligation is calculated. Further, section 95856(I)(2) is specific in addressing that "the total number of compliance instruments submitted to fulfill the triennial compliance obligation is subject to the quantitative use limit..." Therefore, any suggestion that the 8% offset usage limit should apply to the annual surrender of compliance instruments would disrupt the existing surrender regime under which participants have been operating since the Program began. Indeed, if read literally, the proposed amendment could be read to allow an entity to retire offset credits to fulfill up to 8% of an annual obligation, and another 8% of a triennial obligation.

Accordingly, any changes to 95856(h)(I) and (2) must be consistent with retention of the 8% offset limit only at the Triennial Compliance Obligation surrender stage and should be clarified. (SEMPRA 3)

> **Response:** Section 95856(h)(1)(A) was modified in the 15-day language to specify the percentage of offsets (8%) which may be submitted for emissions with a compliance obligation pursuant to section 95855. This change does not affect the quantitative usage limit that applies to the triennial compliance obligation. The triennial compliance obligation to which the 8 percent offset usage limits applies is the total emissions during the entire compliance period and not just the balance of emissions remaining after the annual surrender events. Staff therefore does not agree that the text in section 95856(h) requires modification as it is consistent with the definition of quantitative usage limit.

G-1.19. Comment: GARB is proposing to retire compliance instruments from an entity's compliance account on an annual and triennial basis. On an annual basis, GARB would retire 30 percent of a covered entity's compliance instruments correlated to its compliance obligation reported from the previous data year that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to §95131 of MRR. While this amendment would alleviate potential violation of an entity's holding limit, LADWP recommends that entities be provided the opportunity to request retirement of a larger percentage of its compliance instruments on an annual basis.

The 15-day changes state that CARB will retire offset credits up to eight percent of the emissions with a compliance obligation. LADWP supports this change, as entities would be able to use offsets contained in their compliance account in excess of the eight percent limit for compliance in future years. (LADWP 3)

> **Response:** Thank you for the support. ARB staff notes that the modifications to section 95856(h) do not result in any change to the offset quantitative usage limit of 8% of a triennial compliance obligation. With respect to the annual compliance obligation, staff did not propose any modifications to section 95855 (which specifies the annual compliance obligation) in either the 45-day or the 15-day revisions, so to the extent this comment is suggesting changes to the annual compliance obligation, this comment is outside the scope of the proposed amendments.

G-1.20. Multiple Comments: With that said, there have been some last-minute changes to the 15-day package having to deal with the eight percent offset limit and annual surrender requirement. We have expressed our concerns to the staff about that late change, and there are a number of concerns that we've expressed in prior comment letters, the most recent one going back -- not the one dated April 24th. The most recent one going back to February 28th where we think there's still a list of issues that need to be addressed in future proceedings. And we would hope that we can retain the staff's attention on that and the Board's attention on that so that as these proceedings develop and continue to proceed, that we can incorporate some of those concerns into that. (CCEEB 3)

Comment: With that said, we have registered our concerns in recent conversations with staff regarding the last minute change to language in the 15-day package dealing with application of the 8% offset limit to annual surrender as contained in Section 95856(h)(I)(A). We believe this change removes important flexibility that is absolutely necessary when dealing in a still nascent offsets market. For example, flexibility is critical because there will likely be inadequate supply to meet demand annually. We ask for a commitment, which we believe we received in recent conversations with staff, to return to the previous regulatory language which contained the phrase "without consideration of the quantitative usage limit set forth in section 95854", while removing the language added in the15-day package that says "up to eight percent of the emissions with a compliance obligation pursuant to section 95855". We understand the importance of moving forward with approval of the current 15-day package and support staffs commitment to address this issue in the upcoming set of regulatory amendments (which are expected to go into effect 1/1/2015) this fall. (CCEEB 4)

> **Response:** Thank you for the comment. During the 15-day comment period, staff specifically requested input on implementing an annual offset limit. Stakeholders overwhelmingly supported the ability to retire up to eight percent of emissions with a compliance obligation pursuant to section 95855 at the annual compliance obligation. Staff understands the desire for flexibility in compliance and offsets can be kept in the general account rather than transferring them to the compliance account if the entity does not want to use offsets for the annual compliance obligation.

G-1.21. Comment: BP is disappointed that these latest regulatory amendments remove important flexibility in the use of offsets by applying the offset limit on an annual basis as opposed to at the end of a compliance period. BP strongly supports application of the 8% quantitative limit on the use of offsets only at the triennial compliance surrender. Such flexibility would allow for the most cost effective compliance by allowing the full cost control potential of the limited use of offsets to be realized, while also acknowledging the nascent state of the offset market and current limited supply relative to demand.

As staff is well aware, offsets play a vital role in cost containment for the cap and trade program – while maintaining the environmental integrity of the environmental goal. The use of offsets also serves to create a class of carbon-reduction entrepreneurs who would otherwise not be engaged in helping to address climate change. While staff is no doubt aware that BP we would like to see the offset limit raised, until that time it is important that the limited quantity of offsets able to be used are capable of providing their full impact and benefit. Flexibility as to when the total allowed offsets for the compliance period can be surrendered is key to achieving the full benefits of the limited use of offsets.

While the offset market continues to develop, we can foresee situations where a transient lack of offset availability makes it difficult for regulated entities to use up their full quota of offsets at particular surrender dates. The flexibility brought about by applying the offset quantitative limit at triennial surrender rather than at annual surrender would allow regulated entities to make up for an inability to use sufficient offset volumes in past compliance years (within a full compliance period). Flexibility in the application of the quantitative limit maintains integrity of the cap while allowing for greater use of offsets in situations where there may be temporary allowance spikes or liquidity problems – so long as the 8% offset limit is maintained at the triennial surrender.

All these outcomes will allow for smoother, lower compliance costs, help businesses and consumers, contribute to the longer term sustainability of the program, and allow deeper emission reductions to be sought. BP, therefore, fully supports the application of the 8% quantitative limit on the use of offsets only at the triennial compliance surrender. (BP 2)

> **Response:** The intent of the annual offset limit is to provide entities with flexibility in compliance and to ensure that, if desired, entities can surrender offsets at the annual compliance obligation up to 8% of their compliance obligation. This specification will help avoid "lost" offsets, meaning those that might have been retired during the annual compliance surrender in excess of the quantitative usage limit. If entities do not wish to surrender offsets at the annual compliance event they have the option of keeping the offsets in the general account rather than transferring them to the compliance account. Staff believes

that this offers covered entities flexibility in compliance and can ensure that the entities are able to use their full allotment of offsets for compliance.

G-1.22. Comment: WSPA supported the prior 15 day draft that allowed offset credits to be surrendered without an annual 8 % limit. If any limit at all is applied to offset use, it should be applied only to the full compliance period. The imposition of an annual limit is contradictory to, and inconsistent with, the intentional multi-year (two or three year) compliance period flexibilities built into the program. Moreover, an annual limit would likely act, in reality, to limit the use of offsets to significantly less than 8 percent since there is variability in the development and implementation of offset projects and offset supply. Remove the 8% limit on use of offsets. (WSPA 5)

Response: Thank you for the comment. During the 15 day comment period, staff specifically requested input on implementing an annual offset limit. Stakeholders overwhelmingly supported the ability to retire offsets for up to eight percent of emissions with a compliance obligation pursuant to section 95855 at the annual compliance obligation. Staff understands the desire for flexibility in compliance, and offsets can be kept in the general account rather than transferring them to the compliance account if the entity does not want to use offsets for the annual compliance obligation. ARB is committed to ensuring sufficient offsets are available and will continue to work in bring more offset protocols to the Board for approval.

G-1.23. Comment: In the January 2014 discussion draft, ARB specifically asked stakeholders whether the offset usage limit should apply on annual compliance years, or only the triennial compliance years. The subsequent 15-day proposed amendments have instituted the 8% annual limit.

In IETA's February 2014 comments, we recommended that there should be no 8 percent usage limit on offsets in annual compliance surrender years, and we continue to advocate this position. If an entity over-surrenders offsets in its annual compliance years to the extent that it is already beyond its 8 percent limit by the triennial compliance deadline, ARB should devise means to allow those over-surrendered offset credits to retain value – whether that be through returning the units to the compliance entity, allowing those excess units to be applied towards the next compliance period, or some other means. (IETA 2)

Response: Section 95856(h)(1)(A) specifies that the Executive officer will retire from the compliance account offset credits up to eight percent of the emissions with a compliance obligation pursuant to section 95855. If, at the annual surrender event, an entity is holding offsets in the compliance account in excess of eight percent of its emissions with a compliance obligation pursuant to section 95855, the additional offsets will remain in the compliance account until the next compliance surrender. Therefore, an entity will not "lose" offsets if it over-surrenders at the annual compliance event because no more than eight percent of the annual emissions number will be retired. If, at the triennial compliance event, an entity over-surrenders offsets by moving them into the compliance account, no offsets in excess of the eight percent of the compliance period total emissions will be retired, ensuring there are no "lost" offsets. ARB staff believes the proposed amendment offers ample flexibility in compliance and will help ensure that the full quantitative offset limit can be realized for each entity.

G-1.24. Comment: It Is Appropriate To Require Retirement Of Instruments To Meet The Annual Compliance Obligation And To Apply The Quantitative Usage Limit To The Annual Obligation As Well, So Long As Failure To Use The Entire 8% Allotment At An Annual Compliance Obligation Does Not Reduce The Total Number Of Offset Credits That Can Be Used To Meet The Triennial Obligation. The Regulation does not currently indicate in what order compliance instruments will be retired from covered entities' compliance accounts into CARB's Retirement Account. The Proposed Amendments would mandate such a retirement order and, in so doing, create the risk of entities placing too many offset credits into their compliance accounts prior to an annual compliance obligation becoming due; if the number of offset credits surrendered should ultimately exceed the quantitative usage limit at the end of the compliance period, the excess offset credits would possibly be "lost" and of no value to the entity, which could diminish the cost-containment role offset credits are supposed to play in the Cap-and-Trade Program.

To avoid the risk of over-surrendering offset credits, CARB initially proposed in the 45-Day Proposed Amendments that, rather than retiring compliance instruments, CARB would determine whether a covered entity has fulfilled its annual compliance obligation simply "by evaluating the number and types of compliance instruments in the Compliance Account." In the 15-Day Changes, CARB has now proposed to retain the existing Regulation's retirement of compliance instruments at the annual compliance obligation and, to avoid the risk of over- surrendering offsets at such time, to also apply the quantitative usage limitation to the annual compliance obligation.

Calpine strongly supports the proposal to retain the annual compliance obligation; members of the public can only reasonably expect that compliance instruments will be retired when "used" to satisfy a compliance obligation. With respect to application of the quantitative usage limit to the annual obligation, Calpine believes this is a sound approach, so long as it is true – as we believe is reflected by the 15-Day Changes – that surrendering less than 8% offset credits at any annual obligation does not reduce covered entities' ability to surrender offset credits for up to 8% of their total compliance obligation in a compliance period, as authorized by the existing Regulation. (CALPINE 4)

Response: Thank you for the comment. The proposed modifications to section 95856 are intended to offer flexibility for entities in determining how to surrender instruments for compliance. Under the proposed amendment, surrendering less than 8 percent of the emissions with a compliance obligation pursuant to section 95855 at the annual compliance obligation will not reduce an entity's ability to surrender offsets up to the quantitative usage limit at the triennial compliance surrender.

G-1.25. Comment: The 15-day changes state that CARB will retire offset credits up to eight percent of the emissions with a compliance obligation. LADWP supports this change, as entities would be able to use offsets contained in their compliance account in excess of the eight percent limit for compliance in future years. (LADWP 3)

Response: Thank you for the support.

G-1.26. Comment: A previous cap-and-trade Discussion Draft would have allowed the ARB to take offsets from an entity's compliance account in excess of the current 8% offset usage limit. Staff indicated that excess offsets would not be returned to the compliance entity's account, nor would they be used for compliance anywhere within the cap-and-trade program. In these 15-Day Modifications, Staff has attempted to solve this problem by applying an 8% offset Quantitative Usage Limit to annual and triennial compliance obligations.

SCE strongly believes that the Quantitative Usage Limit should apply to the total covered emissions of an entity in a given compliance period, regardless of how that entity may or may not have surrendered offsets to satisfy their previous annual compliance obligations. These 15- Day Modifications do not clearly state whether entities unable to surrender offsets in the early years of a compliance period can maintain the ability to turn in offsets totaling up to 8% of their covered emissions at the end of each compliance period. SCE urges the ARB to make this clarification explicit in the 15-Day Modifications to provide additional certainty to covered entities (SCE 4)

Response: Thank you for the comment. The proposed modifications to section 95856 are intended to offer flexibility for entities in determining how to surrender instruments for compliance. Therefore, surrendering less than 8 percent of the emissions with a compliance obligation pursuant to section 95855 at the annual compliance obligation will not reduce an entity's ability to surrender offsets up to the quantitative usage limit at the triennial compliance surrender.

In addition, if, at the annual surrender event, an entity is holding offsets in its compliance account in excess of eight percent of their emissions with a compliance obligation pursuant to section 95855, the additional offsets will remain in the compliance account until the next compliance surrender. Therefore an entity will not "lose" offsets if it over-surrenders at the annual compliance event. ARB staff does not agree that the text requires additional modification and will consider providing guidance on this issue to ensure entities are able to comply with the requirements.

G-1.27. Comment: CARB staff proposes to reinstate annual retirement of compliance instruments in section 95856(h)(1)**.** WPTF's preference is to retain the approach taken in the 45-day text, which would have eliminated the annual retirement of compliance instruments and replaced it with provisions for CARB to evaluate annually whether each covered entity has sufficient instruments in its compliance account. The fact that this approach would obviate the need for an annual offset cap is the fundamental reason that we prefer to eliminate annual retirement.

If staff decides to retain annual retirement, then WPTF would oppose imposition of an annual 8% offset limit. Instead, we recommend that CARB implement a flag in CITSS that would notify a covered entity if it designates a quantity of offsets in excess of 8% of covered emissions to date for movement between its compliance account and the retirement account. At the end of the compliance period, any offsets that have been moved to the Retirement account in excess of the 8% limit for that period should be applied toward the entity's compliance in the subsequent compliance period. In no circumstances, should annual retirement of offsets in excess of 8% lead to an entity's loss of those offsets after the triennial retirement.

Lastly, we reiterate our request that CARB eliminate the mandated order of retirement instruments and instead build functionality into CITSS that would enable individual account holders to designate compliance instruments, by type and vintage, for retirement. If that functionality cannot be built into CITSS, WPTF suggests entities be given an opportunity to provide written instructions to the Executive Officer, a minimum of five (5) days prior to the annual and triennial surrender deadlines. If an entity fails to provide such instructions, the default retirement order would apply. WPTF believes that the Quantitative Usage Limit should apply in both instances, if an entity provides an order of retirement, or if the default retirement order is utilized. This will prevent the "over retirement" of instruments that may not contribute toward satisfying a compliance obligation. (WPTF 3)

> **Response:** Thank you for the comment. During the 15-day comment period, staff specifically requested input on implementing an annual offset limit. Stakeholders overwhelmingly supported the ability to retire up to eight percent of emissions with a compliance obligation pursuant to section 95855 at the annual compliance obligation. ARB staff understands the desire for flexibility in compliance and offsets can be kept in the general account rather than transferring them to the compliance account if the entity does not want to use offsets for the annual compliance obligation. While staff appreciates the suggestion that modifying the CITSS to notify an entity of an offset over-compliance that functionality does not currently exist nor could it be practically implemented.
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> Section 95856(h)(1)(A) specifies that the Executive officer will retire from the compliance account offset credits up to eight percent of the emissions with a compliance obligation pursuant to section 95855. If, at the annual surrender event, an entity is holding offsets in the compliance account in excess of eight percent of their emissions with a compliance obligation pursuant to section 95855, the additional offsets will remain in the compliance account until the next compliance surrender. Therefore, an entity will not "lose" offsets if it over-

surrenders at the annual compliance event because no more than eight percent of the annual emissions number will be retired. If, at the triennial compliance event, an entity over-surrenders offsets by moving them into the compliance account, no offsets in excess of the eight percent of the compliance period total emissions will be retired ensuring there are no "lost" offsets. Staff believes the proposed amendment offers ample flexibility in compliance and will help ensure that the full quantitative offset limit can be realized for each entity.

G-1.28. Comment: The prior Proposed Discussion Draft released January, 2014 provided that offsets could be retired "without regard to the quantitative usage limits set forth in Section 95854." Chevron supports this policy and is disappointed that ARB has changed it to an annual limit. Annual restrictions remove flexibility both for early compliance and may be interpreted to impact later compliance. The proposed change works against flexibility that ARB had granted to allow offsets limitations to apply only on a triennial basis.

Flexibility is needed to allow full participation in the offsets market. The proposed change will disproportionally impact covered entities with smaller compliance obligations. Based on market experience, transactional costs associated with purchasing offsets over the counter make it impracticable and expensive to trade offsets in small quantities. Accordingly, it will be difficult if not unlikely for market participants to be able to contract offsets to receive delivery on an annual basis to meet the proposed change. Participants need to purchase and retain offsets in quantities sufficient for efficient management.

Without full participation, offsets are not as effective as a cost containment mechanism and therefore costs to all covered entities will increase. Early compliance will stimulate the market. Limiting amounts of offsets for later submission will reduce the use of offsets. Offsets are a key cost containment mechanism that requires flexibility to be effective.

Recommendation: Chevron recommends that ARB return to the regulatory language originally proposed in the Discussion Draft dated January 31, 2014. (CHEVRON 6)

Response: Thank you for the comment. During the 15-day comment period, ARB staff specifically requested input on implementing an annual offset limit. Stakeholders overwhelmingly supported the ability to retire up to 8 percent of emissions with a compliance obligation pursuant to section 95855 at the annual compliance obligation. Staff understands the desire for flexibility in compliance and offsets can be kept in the general account rather than transferring them to the compliance account if the entity does not want to use offsets for the annual compliance obligation. In addition, ARB is committed to ensuring sufficient offsets are available and will work to bring additional offset protocols to the Board.

Section 95856(h)(1)(A) specifies that the Executive officer will retire from the compliance account offset credits up to eight percent of the emissions with a compliance obligation pursuant to section 95855. If, at the annual surrender event, an entity is holding offsets in the compliance account in excess of eight percent of its emissions with a compliance obligation pursuant to section 95855, the additional offsets will remain in the compliance account until the next compliance surrender. Therefore, an entity will not "lose" offsets if it over-surrenders at the annual compliance event because no more than eight percent of the annual emissions number will be retired. If, at the triennial compliance event, an entity over-surrenders offsets by moving them into the compliance account, no offsets in excess of the eight percent of the compliance period total emissions will be retired, ensuring there are no "lost" offsets. Staff believes the proposed amendment offers ample flexibility in compliance and will help ensure that the full quantitative offset limit can be realized for each entity.

G-2. Annual Allowance Holding Account

G-2.1. Comment: CARB proposes to create an annual allocation holding account for an entity that receives a direct allocation to prevent an entity from violating its holding limit with future year vintage allowances that are deposited prior to the compliance year (e.g. to prevent CARB's deposit of an entity's 2015 allowance allocation in its account on October 24, 2014 from leading to a violation of the entity's holding limit). LADWP supports this action as it would be unreasonable for an entity to incur a violation of its holding limit for a regulatory agency deposit of future year allowances. (LADWP 3)

Response: Thank you for the comment and support.

G-2.2. Comment: It appears ARB created a new "annual allocation holding account" to ensure allowances allocated prior to the beginning of the following year will not cause an entity to exceed its holding limit at the time of allowance allocation (October 25 or the first business day thereafter). As further specified in §95870, the allocated allowances remaining in this account will automatically be transferred by ARB to the entity's Holding Account on the first business day of each year. It seems unnecessary to restrict the opportunity to transfer allocated allowances into the compliance account only between October 25 and the first business day in January. Entities should be able to trade credits allocated as currently allowed out of such an account. Because this new account is not subject to the holding limit, we understand ARB may want to restrict additional CIs from being deposited into this account.

The rule language should clarify that allowances in the annual allocation holding account are not subject to the compliance account holding limit and not restricted in their ability to be transferred between October 25th of one year and January 1st of the following year. (WSPA 5)

Response: ARB staff does not agree that the text requires clarification. The intent of the language is to restrict the movement of allowances from the annual allocation holding account to prevent inadvertent holding limit violations. The intent is that allowances are not to be transferred from this new account to the general account prior to the January 1 of the vintage of the allowances. As such, staff does not believe further changes are necessary.

Shutdown of Covered Entity or Opt-in Covered Entity

G-2.3. Comment: Tesoro appreciates the opportunity to comment on the regulatory package and seeks clarification on three provisions:

1. 95812(f)(3): Please clarify that the phrase "within 30 days of fulfilling its compliance obligation" refers to the final allowance retirement that may occur up to three years after the year in which the facility was shutdown.

2. 95812(f)(3): Please confirm that the "formerly covered entity" referenced in this provision is considered the same entity that is converted to a voluntary associated entity pursuant to 95812(f)(2). (TESORO 3)

Response: ARB staff agrees that the reference in section 95812(f)(3) pertains to date of compliance surrender. The term “formerly covered or opt-in covered entity” refers to the entity that has shut down. That entity may then request permission from the Executive Officer to remain in the tracking system as a Voluntarily Associated Entity pursuant to section 95812(f)(3).

H. IMPLEMENTATION OF AUCTION AND TRADING REQUIREMENTS

H-1. Corporate Association Disclosure

General

H-1.1. Comment: We believe that important issues remain to be resolved that would allow the cap and trade program to function efficiently and without unnecessary burden to regulated entities - while minimizing the potential for fraud.

BP understands the need for CARB to be aware of and track corporate associations for those participating in the state's cap-and-trade program. However, under the currently proposed rule, the requirement that a company lists all of its corporate associations, regardless of whether those corporate associations have any connection to or have ever participated in the cap-and-trade program, is onerous and unnecessary to the proper functioning of the program. We are disappointed that the potential regulatory amendments continue to overlook important and valid concerns raised by BP and other stakeholders without, in our view, providing sufficient rationale for what we believe is an expansive, troublesome and unnecessary request for information.

BP, as one of the largest and most diverse corporations in the world, has thousands of ever-changing corporate associations across the globe that would potentially fall under the overly broad reach of the proposed regulation. The vast majority of these corporate associations – whether they are a wind farm in Texas, a refinery in Ohio or Australia, or a pipeline in Azerbaijan - are not even remotely related to or impacted by BP's transactions in CARB's cap and trade program. The proposed amendments significantly broaden reasonable reporting requirements by removing the language in 95830 (c)(1)(H) which limited reporting to associations with entities registered pursuant to this article and by adding language in 95833 (a)(1) which requires reporting of these associations regardless of whether second entity is subject to the requirements of this article. Our understanding of staff's concerns that prompted these changes is that apparently some regulated entities were not reporting these associations even under the previous, more limited language. Staff is apparently also concerned about associations that may involve entities operating outside of California in linked programs. With regard to the former concern, if entities are not complying because they are uncertain of the requirements, then staff should focus and clarify the requirements – not significantly broaden them. If some entities are willfully not complying, it is appropriate enforcement - and not overly broad regulatory language that unreasonably impacts all regulated entities - that staff should pursue.

The broader requirement (which also relies upon entities to properly report) would put a significant burden on both regulated entities and on CARB staff. Instead of being alerted to associations between entities who are involved in the California cap and trade program, staff would be inundated with tens of thousands of (mostly inconsequential) associations with the burden of then attempting to cross reference these associations in search of a potential violation. On the issue of linked programs, we suggest that the regulation simply include a requirement to list corporate associations with entities registered in a linked program. Furthermore, the regulation includes a requirement that registrants update registration information within 30 working days of any change. This would mean that BP would be required to notify CARB within 30 days of a change within any one of thousands of corporate association around the globe. We are simply not set up as a corporation to provide internal let alone external notification of such changes within this sort of timeframe. Thirty days notification is a reasonable requirement when the reporting of associations is limited to entities registered in the California program – or within linked programs. It is a wholly unreasonable requirement when it applies to thousands of associations around the globe with no relationship to the California program. Moreover, additional, significant and unreasonable impact could occur when these changes are coupled with additions to subsection 95912(d)(5) which now reads:

An entity with any changes to the auction application information listed in subsection 95912(d)(4) within 30 days prior to an auction may be denied participation in the auction.

BP routinely buys and sells business lines in response to changes in the prospects of particular products or markets around the world. When combined, these new changes mean that if BP buys or sells certain entities, changes a corporate association anywhere in the world, or has a personnel change within 30 days prior to an auction – BP, a regulated entity with a large compliance obligation, may be denied participation in the auction because of the vast number of corporate associations it has. This is simply unreasonable by any standard. BP strongly recommends that the proposed language r removed from 95830 (c)(1)(H)(registered pursuant to this article) be restored and that the added language in section 95833 (a)(1) which requires reporting of these associations regardless of whether second entity is subject to the requirements of this article –be removed -with the result being that reporting of associations is only required when those associated entities are participating in the California cap and trade program and/or a program linked with the California program. If necessary, the regulation should seek to clarify these requirements rather than broaden them. Making these recommended changes will make the requirement manageable for the large corporate entities who would be most affected by this change. With these recommended changes, the required notification of changes in corporate associations, as well as the attestation required for ongoing investigations related to corporate associations also become more manageable. As previously stated, we suggest that the regulation include a requirement to report associations with entities registered in linked programs. We believe it is clear that without these recommended changes, the regulation will be needlessly burdensome and problematic for both staff and regulated entities and will cause unintended consequences for regulated entities who are attempting to act in good faith. (BP 2)

Response: See response to 45-day comments H-2.18.

H-1.2. Comment: I wanted to focus on a single issue that's very important to us, one that we've not been able to work out with staff. And that is this issue of reporting of corporate associations. The revised regulatory language would require that we disclose every corporate association anywhere in the world, regardless of whether it has any connection to the AB 32 program. Staff did add a caveat that this entity would have to be involved in power or energy or carbon. As you can imagine, that wouldn't clear the decks for us very much. Disclosure of this information comes at a big price, a big price in terms of manpower, assembling it, compliance risk, as you heard from being able to keep up with all the changes. And business risks from disclosing a lot of relationship that we haven't in this way any time before. I checked on the number of these sort of relationships that we have in BP just in the US, it's about 500. And we do business in about 70 countries. So you can do the math on that. The regulation also requires that we update these relationships regularly. And worse, that we are able to attest about any investigations that have gone on in any of these entities anywhere in the world in relation to a commodity market. That's not only a lot of work, but as has been said before, brings about a lot of compliance risk if we don't get this information right. And we agree that we should be required to report on any related entity that's involved in the Cap and Trade Program. We were told by staff that the massive broadening of this requirement is due to the fact that apparently some entities were not reporting sufficiently or appropriately on the more limited language that was in the previous regulation. But we think that if companies are willfully not complying, the answer really is appropriate enforcement, and not broadening of the regulation that captures regulated entities that are complying. It's not going to age staff in their compliance and making sure people comply. If they know that we own part of a pipeline and in Azerbaijan or part of a biofuel facility in the UK if these entities have no connection to the California program. So we ask that the Board direct the staff to go back to the previous language it had in the original regulation that requires this sort of reporting only when these related entities have the connection to the California program. Thank you. (BP 3)

Response: See response to 45-day comments H-2.18.

H-1.3. Comment: Secondly, I'd like to turn to the recent regulatory requirements aimed at combating market manipulation. Southern California Edison agrees that market manipulation is a real concern and that sensitive information in the wrong hands can lead to real market distortions. While the concern is real, the regulatory measure put in place to guard against is present significant compliance challenges for large market participants like us. There are requirements to disclose employees with market information, to attest to historical investigations regardless of the outcome, to inform the ARB every time we meet with our procurement review group or fulfill a PUC data request. They're onerous. Stakeholders for many industries have voiced their concern on this point and the ARB has responded by narrowing the scope in some instances. We thank you for that. But overall, these regulations will still need clarity. They're still going to require significant and sustained administrative effort. And they still leave open, honestly, the possibility of creating compliance traps. Where despite a covered entity's best intentions and efforts due to the vast scope of these regulations, an entity can be found non-compliant and possibly barred from auction participation and/or fined. Southern California Edison sincerely requests the ARB engage with stakeholders to identify solutions which can deliver useful information to the Air Resources Board without such a high administrative burden. Southern California Edison has laid out some of those proposals in its written comments and looks forward to working with other stakeholders to identify further solutions for proposal.

When the ARB opens the regulations this fall hopefully to include the rice offset protocol and others changes, Southern California Edison requests this agency update this information disclosure requirements to add clarity to their scope and reduce the serious administrative efforts necessary to comply. (SCE 5)

> **Response:** See Response to 45-day comment H-2.18.
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> A rice cultivation protocol is not included in this rulemaking and any comments related to that protocol would be considered and addressed during the public process associated with the evaluation of that protocol during future potential rulemaking.

H-1.4. Comment: While we support adoption of the package today, we do hope for continued dialogue with staff on some provisions that can be modified in future rule makings. I'll mention just two of those today. We would like to see less complicated administrative report and recordkeeping requirements related to corporate association. Companies like ours maintain hundreds of corporate associations, most of which have no bearing on the Cap and Trade Program. It is not just the administrative burden of maintaining these records, but it is more about the enforcement risk it brings if the records are not updated within the time requirements of the regulation. Both WSPA and Tesoro have submitted comments on the subject that can be used to further discussions with staff. (TESORO 5)

> **Response:** The intent of the proposed amendments is not to impose undue burdens on entities but to ensure a well-functioning market and a level playing field for all market participants. ARB staff will continue to work with stakeholders in guidance to ensure that full market oversight can occur while minimizing the associated administrative burden to the extent feasible.

H-1.5. Comment: And finally, as you heard, there are questions associated with the administrative requirements which could be addressed as well. (WSPA 6)

> **Response:** ARB staff will continue to work with stakeholders in guidance to ensure that full market oversight can occur while minimizing the associated administrative burden to the extent feasible.

H-1.6. Comment: ARB proposes to dramatically expand the definition of a Corporate Association in Section 95833(a)(1) by specifying that such corporate associations exist “regardless of whether the second entity is subject to the requirements of this Article.” CPEM submits that this change is unnecessary, extremely burdensome, and can result in unintended and unfair consequences.

CPEM appreciates the ARB's desire to understand the existence of affiliations among entities that may be participating in the Cap-and-Trade market. However, many participating entities may be part of large corporate families, including entities that are not controlled by, or under common control with, the participating entity, and the ARB must consider the consequences of this change on its regulatory regime. For example, Section 95912(d)(4) provides that an entity whose auction information changes within 30 days prior to an auction may be denied participation in the auction. CPEM understands that a corporate merger of two entities with compliance requirements immediately before an auction could cause the ARB some concern. However, placing an entity's opportunity to participate in an auction in jeopardy because of merger activity of a distant affiliate – perhaps operating in a different industry, on a different continent, and over whom the participating entity has no control, but which could change the participating entity's list of corporate associations – seems patently inappropriate.

CPEM respectfully requests that the ARB decline to adopt the proposed change to Section 95833(a)(1). To the extent the ARB adopts this change, CPEM asks that Staff explain, in its Final Statement of Reasons, (1) how information about corporate association not related to entities subject to the Cap-and-Trade requirements will be used by the ARB; and (2) the specific circumstances under which a participating entity may be denied participation in an auction due to changes in corporate associations. (CPM 2)

> **Response:** See response to 45-day comments H-2.18.
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> With respect to the portion of the comment concerning section 95914(d)(4), ARB staff notes that the intent of section 95912(d)(4) is not to inadvertently prevent auction participation but to ensure that there is proper market oversight specifically pertaining to auction participation. Staff believes that identifying direct corporate associations, regardless of registration status, is vital to properly analyze secondary markets on the periphery of the primary Cap-and-Trade allowance market. Entities not registered in the program, but operating in related markets, may have undue influence on the market. By identifying relationships between entities across markets and commodities, ARB can better ensure a well-functioning primary market. Staff will continue to work with stakeholders through guidance to ensure that full market oversight can occur while minimizing the associated administrative burden to the extent feasible.
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> Staff does not agree with the requested removal of the proposed clarification to section 95833(a)(1) and will consider providing further implementation guidance to assist entities comply with the attestation requirement in section 95912(d)(4). While much of ARB's market monitoring processes are necessarily confidential, staff will address, to the extent feasible, additional explanation of market monitoring and information related corporate association.

H-1.7. Comment: Brookfield opposes the language proposed by CARB in section 95833(a)(1) that extends corporate association provisions to include affiliated entities "regardless of whether the second entity is subject to the requirements of this article". This addition will be unnecessarily burdensome on market participants and it is unclear what benefits acquiring information about corporate entities that don't participate in Cap-and Trade provide to CARB. (BEM 2)

> **Response:** Since the modifications to section 95833(a)(1) were made during the 45-day amendments, and not further modified during the 15-day revisions, this comment is outside the scope of the proposed amendments and no response is required.

H-1.8. Comment: WPTF remains extremely concerned that this version of the regulation retains changes in section 95833 that expanded the scope of corporate associations to include other entities that are not subject to the cap and trade program; and changes proposed in January that would identify multiple covered entities whose compliance strategy is managed by a single account manager and treat these entities as having a direct corporate association. The wide net created by the proposed scope in combination with other regulatory requirements for disclosure of information regarding entities with which a registered entity has a corporate association, in particular the provision in section 95912 requiring an attestation of any investigation, creates a burdensome and possible unworkable standard.

We therefore urge CARB to narrow the scope of corporate associations so that it does not extend to entities that are not subject to the cap and trade program and to eliminate section 95833(f)(7). (WPTF 3)

> **Response:** ARB staff appreciates the concern in balancing the collection of data required for prudent and expedient market oversight with the administrative burden required in the collection, processing, and updating of information pertaining to corporate associations and auction participation. Staff believes that identifying direct corporate associations, regardless of registration status, is vital to properly analyze secondary markets on the periphery of the primary Cap-and-Trade allowance market. Entities not registered in the program, but operating in related markets, may have undue influence on the market. By identifying relationship between entities across markets and commodities, ARB can better ensure a well-functioning primary market. Staff will continue to work with stakeholders through guidance to ensure that full market oversight can occur while minimizing the associated administrative burden to the extent feasible and ensuring entities are not unintentionally preventing from auction participation.
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> Staff does not agree that section 95833(f)(7) should be eliminated as it addresses issues that previously had not been addressed in the Regulation, related to individuals that have primary responsibility for the compliance strategies of more than one entity. Staff believes that section 95833(f)(7) is required to ensure holding and purchase limits are split between entities that are controlled by one individual and is necessary for proper market oversight.

H-1.9. Comment: Chevron Opposes the Disclosure of Corporate Associations, as written. Chevron understands ARB's need to track corporate associations for those participating in the cap and trade program and linked programs to detect fraud and market manipulation. We cannot support the proposed changes, as written, because they require a company to list all of its corporate associations, regardless of whether those corporate associations have any connection to or have ever participated in the cap-and-trade program.

Chevron has over 1,610 such entities, as of April 1, 2014 and nearly 1,000 of those operate outside the United States. Further, many corporate associations operating inside the United States have no delegated corporate authority to conduct any trading related business activity. That is, they have neither impact on nor relation to any transactions in the California cap and trade program. The entities already registered by Chevron represent the only entities authorized by Chevron to conduct trading related activity under the company's corporate policies dealing with delegated authorities. These difficulties are exacerbated by the requirement to report all of the corporate associations quarterly or whenever there are changes. Reporting the details of entities that are unauthorized to conduct trading activities, many of which operate wholly outside of the United States, is not only burdensome, it is also presents a significant potential for inadvertent non-compliance.

> **Recommendation:** Chevron proposes an exemption from this disclosure requirement for publicly traded companies. Alternatively, we would also support changing the language to: "disclosure of corporate associations that have a mandatory or voluntary involvement in, or linkage to, the California cap and trade program" (CHEVRON 6)
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> **Response:** ARB staff appreciates the concern that the requirements related to disclosure of corporate associations are burdensome for large corporations. However, staff does not agree that there should be an exemption from the disclosure requirements for publicly traded companies. Staff believes that all entities should be held to the same standards in disclosing corporate associations and that collection information on registered and unregistered direct corporate associates will ensure that ARB has the ability to properly monitor the market.
>
> Staff does not agree with the commenter's proposed modification to the text which would limit the disclosure of corporate associations to entities with involvement in or linkage to the Cap-and-Trade Program as the language is overly subjective and would require evaluation of "involvement" on an entity basis which would create unnecessary administrative burden on staff and registered entities.
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> In regards to the updating of corporate associations, staff will work with stakeholders in guidance to ensure that full market oversight can occur without inadvertent non-compliance.

H-1.10. Comment: §95912(d)(4)(E) - Auction Participation Attestation. CCEEB members previously commented in September 2013 that the requirement for attestation for an entity and its corporate associations is clearly unreasonable and will place an untenable burden on companies that may, through no fault of the entity, make it impossible to comply. Such a situation would likely lead to an unnecessary and potentially harsh enforcement measures by the ARB, or may lead to auction cancellation. The revised language released on January 31, 2014 continues to be cumbersome and impossible to guarantee compliance.

The following suggested revision is the additional clarification CCEEB requested at its recent meeting with CARB staff. It already fits into one of your categories. If CARB confirms that the corporate associations are limited to only those businesses registered in CA, or in other GHG programs, it is one way to narrow the broad nature of this requirement. We are not sure this is CARB's intent but it is an important clarification that is needed by the regulated community.

Section 95833(b) specifies that if California links to one or more ETS pursuant to Subarticle 12, then entities shall disclose corporate associations with entities registered with those linked programs. This language appears to confirm that the requirement to identify corporate association, direct corporate association, or indirect corporate association is limited to the company registered to do business in California and additional identification of entities registered with other GHG ETS would occur when California links to those programs. Read together, CCEEB proposes an attestation disclosing the existence and status of any ongoing investigation or an investigation that has occurred with the last ten years with respect to any alleged material violation of any rule, regulation, or law associated with any GHG ETS for the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 that are compliance entities pursuant to a GHG ETS. The attestation must be updated to reflect any change in the status of an investigation that has occurred since the most recent auction application attestation was submitted and…

§95833(f)(7) ARB is seeking input on the requirement in this section that entities are considered to have a direct corporate association if they are represented by the same PAR or AAR. CCEEB believes this will place significant burden on smaller entities who are not familiar with the regulation and do not keep up with the changes in the requirements. If ARB has a reservation regarding one person managing CITSS for multiple facilities, we suggest that such burden, instead, be placed on the PAR or AAR. For example, by prohibiting PAR or AAR from representing more than one account if they are not considered to have corporate association, direct or indirect pursuant to §95833.

§95830(c)(1)(H)Eliminate the requirement for identification of all affiliates of a registered entity, or revise to the language that included those entities that are registered in the CARB Trading Program. The current proposal, although changed from 10 days to 30 days, is still an "enforcement trap" for large companies. ARB's reasoning is that such information is necessary based upon potential market manipulation and its experience to date. If ARB has caught these types of problems then it is not clear that there is need for this proposed revision.

This latest change is an improvement, but still involves a large number of individuals within a large organization. Based on a review of the departments typically involved in three activities addressed by ARB in a large company, the number of individuals impacted is in the range of 50 to over 100. This is particularly true for activities related to reviewing transactions or account balances.

Because the Cap-and-Trade compliance process is complex, it involves several departments within an organization. Therefore, there is a high possibility of mis-reporting or missing changes made to staff in the ordinary course of business in time for the deadline for updating information. The possible penalty of being denied registration in the tracking system as specified in §95830(c)(2) is very severe. We recommend that the list of names and contact information be limited to PAR, AAR, and AVA who are already registered with CITSS. Also, we understand that CARB is concerned that an individual working for a compliance entity may inappropriately register as a VAE and that this provision is meant to address this concern. We suggest a better way for CARB to address this concern is to publish a list of names of auction applicants on the ARB web site for public review and comments for 30 days. This way, a company will have a means of ensuring that an employee does not use company information inappropriately.

§95830(f): CCEEB recommends that ARB allow 60 days for applicants to update registration. CCEEB also recommend the timeline to trigger revocation or suspension in section (f)(3) be changed from 10 days to 60 days. Again, the risk of severe penalty warrants the allowance of additional time.

Similarly, we recommend the notification time limit for change to the information disclosed on corporate, direct, and indirect corporate association specified in 95831(e) be changed from 30 days to 60 days as well.

While CCEEB appreciates the changes to Section 95912(d)(5), the language contained in the 15- day discussion draft could still bar an entity from participating in an auction if there are changes to information provided in an entity's auction or account application 30 days before or 15 days after an auction. While this restriction may pose a challenge for any compliance entity, large compliance entities are especially impacted by this provision due to the size and complexity of their business operations. The activities described in the auction or account application cover a range of activities that a company may need to perform in the course of its business and simply cannot remain static in order to participate in the cap-and-trade auctions, including officer names, capital structure, opening of or changes to an investigation, etc.

While ARB staff acknowledges that Section 95912(d) is intended to facilitate effective settlement of the auctions and support market monitoring, and is not intended to be overly burdensome, the language included in the discussion draft encompasses a far wider array of information, including officer names. Section 95912(d) should be further tailored because it unnecessarily jeopardizes an entity's auction participation for activities associated with its normal business operations. CCEEB proposes that Section 95912(d)(5) be revised as follows:

An entity with any changes to the auction application information listed in subsection 95912(d)(4)(A) or (F) within 30 days prior to an auction, or an entity whose auction application information or account application information listed in section 95830(c)(1)(a) will change within 15 days after an auction, may be denied participation in the auction.

§95856- Surrender of Compliance Instruments by covered Entity CCEEB requests more flexibility for entities to be able to designate the retirement order for compliance instruments by type/order as deemed appropriate by the individual entity.

§95821(a)- Tradable Allowances. The term "tradable allowance" introduced in this section creates more confusion. The existing language referred to a single type of allowance. These are allowances that are specified in §95942(b) AND issued by a program approved by ARB pursuant to section 95941. The amended language changes the meaning. It now indicates there are two types of allowances, first are the allowances specified in §95942(b) and the second type are "tradable allowances" issued by a program approved by ARB pursuant to §95941.
However when one examines §95941 and §95942(b), it appears that the insertion of the term "tradable allowances" in §95821(a) is not consistent with these sections and creates confusion. First, §95941 simply authorizes the Board to approve linkage after public notice and comments. How compliance instruments issued by a linked GHG may be used is addressed in the subsequent sections such as §95942. In these sections, the term "tradable allowances" is not used anywhere and does not appear to be necessary. Furthermore, the term "tradable allowances" is not defined in the cap-and-trade regulation. We recommend that this term be deleted from the draft §9582l(a).
It appears that ARB creates a new "annual allocation holding account" to ensure that allowances allocated prior to the beginning of the following year will not cause an entity to exceed its holding limit at the time of allowance allocation (October 25 or the first business day thereafter). As further specified in §95870, the allocated allowances remaining in this account will automatically be transferred by ARB to the entity's Holding Account on the first business day of each year. We have the following comments:

It seems unnecessary to restrict the allowances allocated to only the transfer into the compliance account between October 25 and the first business day in January. Entities should be able to trade credits allocated as allowed today. Because this account is not subject to the holding limit, we can understand the ARB may restrict additional CITSS from being deposited into this account.

- The rule language should clarity that allowances in the annual allocation holding account are not subject to the holding limit.
- Section (6)(C) references the holding limit pursuant to section 95902 (C)(2). This section does not exist, perhaps it may intend to reference section 95920 (c).

While ARB has created accounts to assist in managing compliance instruments to assure holding limits are not exceeded, the restrictions preventing the entity from moving compliance instruments among acc01mts results in assets being stranded, and limits entities ability to optimize their compliance strategy.
CCEEB suggests ARB provide entities the ability to move compliance instruments among the accounts and allow entities to move compliance instruments in and out of the CARB accounts.
If ARB is to implement the concept of "Annual Allocation Holding Account", then we recommend section (c) be changed as follows:
(c) A covered entity must transfer from its holding account or annual allocation holding account to its compliance account a sufficient number of valid compliance instruments to meet the compliance obligation set forth in sections 95853 and 95855.

(h) In response to ARB's request for input, we believe there should be no 8% offset usage limit on the annual surrender event, and that the amount should be determined at the end of the compliance period.

In addition CCEEB would like clarification with regards to the use of True-up amount specified in sections (h)(1)(D), (h)(2)(D) and (h)(3).

While not included in this draft of proposed regulatory changes, CCEEB urges the Board and Staff to consider options current holding limits. CCEEB has expressed concerns of potential flaws with the current holding limits in every comment letter since the initial drafts of the regulation. The ARB continues to delay discussions of modifications to holding limits in the several recent regulatory changes and this Draft. The concerns of the Board and Staff to prevent market manipulation have led to the development of an overly constrained and restricted market. Without immediate consideration of alternatives to existing holding limits it will be too late to prevent the issues anticipated in 2015. CCEEB believes that there are workable alternatives to the current structure of holding limits that will accomplish the same purpose. (CCEEB 4)

> **Response:** This comment was originally submitted for the discussion draft of the proposed regulation order, which was released for public consideration on January 31, 2014 and accompanied by an informal 15-day comment period. As this comment pertains to the informal discussion draft rather than the formal 15-day proposed amendments, no response is required. However, the commenter also submitted this comment letter at the April 25, 2014 Board hearing and therefore staff have included a response in this FSOR. See responses to 15-day

comments G-1.1, G-1.20, H-2.3, and H-2.9 as well as responses to 45-day comments G-2.2, H-2.4, H-2.18, and H-3.44.

H-1.11. Comment: As a general matter, the reporting and Cap-and-Trade programs should be designed to minimize the administrative burdens and transactional costs of regulated entities. TID is concerned that every time the ARB amends its regulations, it adds new informational and administrative requirements that on the whole make AB 32 program compliance increasingly burdensome. These incremental additions expose covered entities to new risks of releasing confidential information and increase compliance costs, particularly for small and medium-sized publicly owned utilities. TID has particular concerns about proposed revisions to Sections 95830(c), 95912(d)(4)(E), 95921, and 95923.

The most recent set of amendments would revise several Sections of the Cap-and-Trade Regulation to expand the informational requirements, create new obligations for allowance transfers, and apparently expand the role of the market monitor. Specifically, as proposed, Sections 95830(c) and 95923 require disclosure of certain employees, contractors and advisors. Section 95912(d)(4)(E) as revised would require disclosure of the existence and status of certain investigations within the last ten years. Section 95921(b) would require the submission of detailed information about an allowance transfer before the ARB will approve a transfer. The information requested includes, among other things, detailed transaction-specific information and copies of contracts. These new informational requirements go beyond the scope of information that was originally intended to be collected by the ARB. Significantly, it is not clear what the ARB plans to do with this information or how confidential information related to allowance transfers would be protected.

According to the ARB, “the market monitor will monitor allowance holding and transfer activity to detect design flaws in the market operating rules, standards, procedures or practices, or to detect structural problems in the market. The systematic collection of detailed transaction- specific information (in particular, copies of contracts) does not further the function of detecting design flaws in the Cap-and-Trade market. The existing reporting requirements (e.g., reporting on transfer prices and ensuring that transfers do not violate the holding limitations) provide more than enough information for the ARB to monitor markets and detect any design flaws. The ARB should not revise Section 95921(b) as proposed. Similarly, the systematic collection of employee, contractor and advisor information regarding past investigations is outside the role of the market monitor as described above.

These new informational requirements create new administrative burdens for regulated entities, especially since the ARB requires that this information be updated on a quarterly basis. To address these issues, the ARB should hold a public workshop where it discusses the information it plans to collect and how that information will be used. The ARB should also consider ways of streamlining these informational requirements (e.g., consolidating the informational requirements into the MRR Reporting Tool and require updating only when the annual report is due). (TID 3)

Response: ARB staff disagrees with the assertion made in the comment that the expanded information requirements are "outside the role of the market monitor." The regulation already contains extensive provisions regarding disclosure of information on employees and consultants, such as auction bid advisors, and the existence of past investigations of an entity's market activities. ARB staff relies on this information to search for undisclosed corporate associations or possible coordinated market activity when individuals work for more than one registered entity. ARB staff has discussed the need for the information and investigations with stakeholders at multiple workshops over the last several years. ARB has conferred with Federal market regulators, such as the CFTC and FERC, as well as the contracted market monitor. These entities have all supported ARB staff's information gathering efforts.

Staff has previously considered the suggestion that the information only be obtained at annual or longer intervals. However, corporate associations, whether disclosed or undisclosed, can change rapidly and alter market competitiveness. ARB staff needs to have timely information to protect the market.

Staff disagrees with the assertion that "The systematic collection of detailed transaction-specific information (in particular, copies of contracts) does not further the function of detecting design flaws in the Cap-and-Trade market." The existing regulation has always contained the provision allowing ARB staff to call in documentation supporting the transactions. ARB staff has used this authority in many cases to investigate potential violations and as part of an effort to ensure the integrity of the collected data. Reviewing transaction agreements allows staff to respond to questions from account representatives, to provide advice on compliance, and to understand the newer types of transaction agreements being developed.

Many of the proposed changes are in response to questions or suggestions from account representatives. The changes fall into two general categories. First, many transaction agreements have complicated terms concerning price or quantities. The changes will allow the account representatives to identify the type of agreement they have and have an appropriate way of entering their information. Account representatives have been clear that the "one size fits all" approach can be too restrictive. The second category of changes concerns transactions agreements that do not generate a readily reportable price. ARB staff has posted an online guidance document that identifies some of these instances, and account representatives have identified others. The new regulation text will allow the account representative to identify the reason that they should be allowed to enter a zero price on the transfer request. This should speed up the transfer process and reduce the number of questions that ARB staff has for account representatives. Overall, most account representatives will not have to enter more detailed information because most transaction agreements are not complicated. Those that have more complicated terms should have a clear path for entering the data and need fewer discussions with staff on compliance.

ARB staff does appreciate the commenter's suggestions regarding streamlining the reporting of these informational requirements, and will continue to work with stakeholders to ensure an efficient implementation of these requirements.

H-1.12. Comment: The modifications made to several sections of the Regulations to address the requirement to update information previously provided to ARB appears to have created an inconsistency between the timing requirements in sections 95830(c)(1)(I), 95830(l)(1) and 95833(e)(3).

Pursuant to proposed section 95830(c)(1)(H), an entity registering for an account in the tracking system must provide certain information to ARB including, among other things: "Identification of all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 . .."
Proposed section 95830(f)(1) states:

Registered entities must update their registration information as required by any change to the provisions of 95830(c) within 30 days of the changes becoming effective. When there is a change to the information registrants have submitted pursuant to 95830(c), registrants must update the registration information within 30 calendar days of the change. Updates of information provided pursuant to section 95830(c)(1)(1) may be updated each calendar quarter instead of within 30 calendar days of the change.

Further, at sections 95833(e)(3) and (4), the language has been modified to specify that:
(3) At least quarterly, for any changes to the information disclosed on corporate, direct and indirect corporate associations, pursuant to section 95830(f)(1); and
(4) No later than the auction registration deadline established in section 95912 when reporting a change to the information disclosed if the changes relate to another entity registered in the Cap-and-Trade Program, otherwise the entity may not participate in that auction.

The proposed revisions are confusing, and could lead to misunderstanding among Program participants. In addition, the revisions are overly burdensome given the complex nature of some Program participant's corporate structure. Therefore, these provisions should be amended to clearly state the following:

Section 95830(f)(1):Registered entities must update their registration information, as required by any change to the provisions of 95830(c), or if a change has occurred to the information provided pursuant to 95830(c), no later than the auction registration deadline established in section 95912. An entity may not participate in the auction if it fails to report this information in a timely manner.

Section 95833(e)(3):At least quarterly, for any changes to the information disclosed on corporate, direct, and indirect corporate associations pursuant to 95830(f)(1). Section 95833(e)(4) should be removed from the Regulations. (SEMPRA 3)

> **Response:** Section 95830(f)(1) has been added to reduce administrative burden by allowing entities to report changes to corporate associations quarterly rather than within 30 days of the change. ARB staff appreciates the concern that there are multiple requirements for reporting changes in information related to registration, but does not agree that the text as modified in the 15-day changes requires further modification. Section 93833(e)(3) is required to ensure that there are no changes to registration information after the auction deadline to prevent inadvertent denial of auction applications due to changes in registration information that are reported in compliance with section 95833(e)(3) but after the auction registration deadline.

H-1.13. Comment: Section 95830 of proposed amendments retains a proposed change within the program that requires identification of all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association. In the currently standing regulation, these association disclosures are only required for associated entities registered pursuant to the program. The new proposal significantly expands the requirement for identification to associations far beyond the reach of the California program.

A number of IETA's members are large corporations with many corporate associations across the globe. For some IETA members, the number is in excess of 1000 affiliates and subsidiaries. The proposed requirement as outlined in the proposed amendments would be very difficult to maintain as hundreds of these associations are constantly changing, making submitted lists obsolete soon after submittal to ARB. Given the magnitude of what is being required, IETA wonders if ARB itself would view it as worthwhile to undertake the management of such a large influx of information.

Further, IETA is unsure why it is of interest to ARB to have record of corporate associations for entities not registered or otherwise involved in the cap-and-trade program. Unless there is some rationale that IETA is not aware of, we recommend reverting to the language as written in the current regulation. (IETA 2)

> **Response:** ARB staff appreciates the concerns raised by the commenter. However, this disclosure requirement is not a new requirement and the disclosure of all corporate associations has been a requirement from the beginning of the Cap-and-Trade Program. The modifications made to section 95833 are intended to provide clarification in the reporting of corporate associates. Information pertaining to corporate associations is central to ARB's market monitoring efforts and maintaining a well-functioning market. Identifying corporate associations is also critical in evaluating the holding limit and purchase limits for entities to facilitate compliance for all covered entities. See also response to 45-day comments H-2.18.

H-1.14. Comment: Tesoro is concerned with the overly broad requirement for identifying corporate associations in 95833 and believes that these associations should be limited to those located in CA or those that participate in the CA GHG program - consistent with the WSPA comments.

Alternatively, if CARB is not willing to focus the language as suggested above, the language should at least be made consistent with 95912(d)(4)(E) regarding attestations and corporate associations where the associations are limited to those who “participate in a carbon, fuel, or electricity market”. Changes should be made to sections 95833 (a)(1), (a)(2), (a)(3), and (a)(4) “An entity has a corporate association with another entity that participates in a carbon, fuel, or electricity market, regardless of whether the second entity is subject to the requirements of this article,…” The excerpt above with the proposed change is taken directly from provision (a)(1), but the proposed change would be similar for the other three provisions listed (TESORO 4)

> **Response:** Thank you for the comment. The changes outlined in the 45-day proposed amendments (that remained static in the 15-day proposed amendments) do not alter the operative language of section 95833(d)(1) which outlines the information required to be disclosed for associated entities, registered and unregistered. The definitions of direct corporate association in sections 95833(a)(1), (2), and (3) have been modified to explicitly clarify that entities not subject to the Cap-and-Trade Regulation that meet the criteria outlined in section 95833 pertaining to a direct corporate association must be disclosed by a regulated entity. Section 95833(a)(4) outlining the definition of an indirect corporate association has not been altered. The intent of this staggered modification is to minimize, to the extent feasible, the administrative burden of the disclosure by requiring the disclosure of indirect corporate associations only for entities registered in the Cap-and-Trade Program.
>
> ARB staff does not agree that section 95833 should be modified to limit the disclosure of corporate associates to entities located in California or those that are registered in the Cap-and-Trade Program. This modification would be overly restrictive and would change the original intent of the Regulation which requires the disclosure of corporate associates regardless of standing in the Cap-and-Trade Program. Staff does not agree that section 95833 should be modified to reflect section 95912(d)(4)(E) as that would not allow for full market monitoring by restricting the disclosure of corporate associates. Modifications were made in the proposed amendments that restricted the attestation requirements in section 95912(d)(4)(E) after consultation with stakeholders. However, staff believes it is necessary for market oversight to collect information pertaining to corporate associations from all entities regardless of registration status or participation in specific markets.

H-1.15. Comment: While IETA appreciates the changes to Section 95912(d)(5), the language contained in the proposed amendments could still bar an entity from participating in an auction if there are changes to information provided in an entity's auction application 30 days before an auction. The activities described in the auction application cover a range of activities that a company may need to perform in the course of its business and simply cannot remain static in order to participate in the cap-and- trade auctions.

ARB staff acknowledges that Section 95912(d) is intended to facilitate effective settlement of the auctions and support market monitoring, and is not intended to be overly burdensome. To accomplish ARB's objectives, Section 95912(d) should be further tailored to only restrict changes to the entity's corporate identity set forth in Section 95912(d)(4)(A). Otherwise, the provision unnecessarily jeopardizes an entity's auction participation for activities associated with its normal business operations or beyond its reasonable control. (IETA 2)

> **Response:** The commenter suggests that section 95912(d)(5) be limited only to section 95912(d)(4)(A), corporate identity and ownership. Staff declines to make this suggested change to the regulatory text as section 95912(d)(4)(B), direct and indirect corporate associations, is necessary to properly determine auction purchase limits and holding limits. If an entity has a change in its corporate associations (an associate is acquired or sold) within 30 days of the date of an auction, that change must be reflected in CITSS prior to the auction so that entity and corporate associate purchase limits are correct, as well as holding limits. Current procedures require that appropriate forms be filed with ARB to effect such a change and the forms must be reviewed by ARB staff before the changes to CITSS can be made. The 30 day window coincides with the close of auction applications in the auction platform, which staff believes is a reasonable date to inform ARB of changes to an entity's corporate associations.

Disclosure of Corporate Associations Not Registered in the Program

H-1.16. Comment: Section 95830(e)(3) also modifies the timeline for disclosing corporate associations in a manner that promotes efficiency while maintaining market integrity. SDG&E and SoCalGas have proposed language to clarify the applicable timeline and have not proposed any substantive changes to Section 95833(e)(3):
No later than the auction registration deadline established in section 95912 after the changes become effective for any changes to the information disclosed on corporate, direct and indirect corporate associations, pursuant to section 95830(f)(1); (SEMPRA 4)

> **Response:** Thank you for the comment. ARB staff does not agree that any modification is required in clarification of the reporting timeline for the disclosure of corporate associations. The addition of "after the changes become effective" is overly subjective. Staff believes that the reporting of a change must occur by the auction registration deadline and does not agree that the proposed modification offers clarity.

H-1.17. Comment: Finally, like many people before me that work for large companies who are concerned about the requirement to report all of our corporate entities, Chevron has over 1,600 entities. Like Ralph who spoke about Azerbaijan, we're from Azerbaijan all the way to Zaire. And it certain isn't necessary to have all of those reports to have this function in a safe manner. So please fix that. (CHEVRON 7)

Response: See response to 45-day comments H-2.18.

H-1.18. Comment: As we commented previously, ARB proposes new language for corporate associations that requires disclosure where there is greater than 20% ownership of any operation worldwide, regardless of whether it is in California or has any C/T program obligation. In large multinational entities, this would likely involve hundreds if not thousands of “associations”. Aside from the burdensome nature of the requirement, attempting to maintain an updated list creates huge enforcement risk for a company and could limit their ability to participate in an auction.

These challenges also would exist for associations with multiple partners, joint ventures, or multiple owners, especially if the entity within the State of California operates independently with its own executive management. For that reason, WSPA opposes the proposed amendments.

ARB should eliminate the proposed new language that requires identification of associations “regardless of whether the second entity is subject to the requirements of this article” and instead state that the requirement should apply ONLY where the association operates in California, or has a mandatory or voluntary involvement in, or linkage to, the California C/T program.

Understanding this is a complex issue and will involve input from numerous stakeholders, we recommend ARB initiate a process to identify and implement alternatives to the currently proposed regulations. (WSPA 5)

Response: See response to 45-day comments H-2.18.

ARB staff appreciates the concern that failure to report changes in corporate associations may prevent entities from participating in auctions. The intent of section 95912(d)(4)(E) is not to create inadvertent violations. Staff will continue to work with stakeholders in guidance to ensure that full market oversight can occur while minimizing the risk of inadvertent violations that will restrict auction participation.

Limited Liability Corporation

H-1.19. Comment: Aera would like to focus its comments on Section 95833(a)(2)(F). Aera believes Section 95833(a)(2)(F) should be revised to read:

"In the case of a limited liability corporation company, owns more than 50% of the other entity regardless of how the interest is held, unless that entity provides documentation demonstrating to the reasonable satisfaction of the Executive Officer that it neither controls nor is controlled by the other entity."

Rationale: Some LLCs have member companies that are totally unassociated market participants but with one of the members (or a group of members, collectively, a "member group") having an ownership interest in the LLC of greater than 50%. Normally, control follows from ownership. However, in some situations, the LLC's governance documents dictate that no member or member group has control over the LLC's activities, despite holding a majority ownership interest in the LLC. In these cases, the LLC acts as an independent entity, and the majority member or member group should be found to have a corporate association with the LLC under section 95833(a)(1), but not a "direct corporate association" under section 95833(a)(2).

As proposed, section 95833(a)(2)(F) creates legal dilemmas for the LLC, its majority ownership member, and any minority members or member groups. The LLC can be put in the untenable situation of having to choose to take actions that could violate the provisions of its LLC governance documents, violate the non-disclosure provisions of section 95914(c), and/or potentially run contrary to state and federal antitrust laws.

Depending on the LLC's governance documents, the minority ownership members would likely have the right to understand the LLC's joint, coordinated strategy that it develops with the majority member because it directly impacts the operational and financial viability of the LLC. Further, the LLC could be required to obtain the unanimous approval of all members in order to implement the joint strategy after disclosure.

In this case, although the minority members would not have a direct corporate association with the LLC, the LLC would be obligated to share with the minority member the details of the purchase strategies it has developed with the majority member, including plans for auction and secondary market participation, as well as bidding and pricing strategy. Holding limits/strategies would also be implicated, including any strategies related to the timing of transfers of compliance instruments to/from third parties or into compliance accounts.

Any sharing of such information by the LLC with its minority members would be a direct violation of section 95914(c). Even if minority members are not directly participating in the cap-and-trade program, they could have corporate associations with other registered and non-registered entities, further multiplying the potential for violations of the non-disclosure provisions of section 95914. If the minority members are covered entities or opt-in covered entities registered and participating in the cap-and-trade program, the end result is that there will be three or more market participants having knowledge of the majority owner's and the LLC's market position, participation, and transfer strategies. The only way the LLC can avoid putting its members in this untenable situation created by section 95833(a)(2)(F) is to violate the provisions of its corporate governance documents. This result is not only patently unfair to the entities involved, it also gives rise to potential antitrust issues.

Section 95833(a)(2)(F) creates serious antitrust implications because it creates the appearance that the LLC and its majority and minority members could be colluding to manipulate one or more carbon markets. There are potential international law implications as well, now that California's cap-and-trade program is linked with Quebec's.

The best solution to avoid the undesirable and unjust outcomes described above is to vest the Executive Officer with the power to review the corporate governance documents of LLCs where ownership does not equate to control over the LLC's actions. Such review could be augmented with objective indicia of non-control, such as the inability of the majority member or member group to obtain any of the following:

1. Appointment or removal of more than 50% of the directors of the LLC;
2. Unilateral appointment or removal of officers of the LLC; or
3. Ability to act unilaterally on behalf of the LLC or commit it to any obligation.

It would not be unreasonable for the Executive Officer to require some form of attestation from the LLC that it will not share market-sensitive information relating to its participation in the cap-and-trade program with the majority member. Because not all information related to the LLC's program participation is market-sensitive, some limited exceptions to the blanket "gag order" could be made to facilitate proper governance of the LLC by its members.

Exceptions could include the following:
1. Forecasted aggregate annual cost of purchasing compliance instruments;
2. Actual aggregate annual cost incurred to purchase compliance instruments;
3. Volume and total cost of compliance instruments associated with any untimely surrender obligation or excess emissions (section 95857);
4. Volume, source and cost of offset credits invalidated by CARB and remedies pursued;
5. Penalties imposed by CARB (section 96013)
6. Violations noticed by CARB (sections 95856, 95857 and 96104)
7. Any other actions taken by CARB that directly affect the LLC's ability to participate in the cap-and-trade program and the reasons therefore (e.g. auction registration rejected by the Auction Administrator).

There are undoubtedly other solutions that can be considered to the situation where LLC ownership does not equate to LLC control. However, the revisions proposed above strike a rational balance between the need for certain LLCs to conduct business and the need to protect the integrity of the cap-and-trade program and related markets. The added language gives the Executive Officer the authority to require that the LLC make its case for being exempted from the finding of a direct corporate association with its majority member. It also vests the Executive Officer with the power to demand enforceable assurances from the LLC that ownership does not equate to control, and that its information sharing with the majority owner will be limited to a closely circumscribed subset of information that is not market-sensitive. Aera appreciates your consideration of its comments (AERA)

> **Response:** ARB staff did not propose any modifications to section 95833(a)(2)(F) in the 15-day changes, so the comment is outside the scope of the proposed amendments. However, staff appreciates the concerns surrounding LLC operating agreements and issues surrounding ownership and control. Staff does not agree that allowing LLCs to submit the attestation suggested by the commenter is sufficient to assuage concerns surrounding the release of market-sensitive information and potential market manipulation by related entities. Section 95833(c) exempts registered entities subject to affiliate compliance rules from disclosing information or taking action that would violate those rules. Staff believes this exemption is sufficient in preventing inadvertent violations of existing antitrust regulations. Staff will continue working with stakeholders, and will consider issuing guidance to assist entities comply with the requirements of the Cap-and-Trade Regulation. Finally, it is not clear how disclosure or treatment by ARB of corporate associations raises antitrust issues. ARB is the market monitor for the disclosures and shared limits.

H-1.20. Comment: The Staff proposes to include an LLC within the meaning of a "direct corporate association," if an entity owns more than 50 percent of the LLC. Ownership of more than 50 percent of the LLC is not enough, however, to establish a "direct corporate association" with an LLC. In order to determine the level of "control" that is required to establish a "direct corporate association" with an LLC in which an entity has an ownership interest, evidence of control should be considered, based on the terms of the LLC's operating agreement and/or through an attestation by an authorized officer. Shell – Martinez Refinery proposes that the ARB include the following language at the end of Section 95833(a)(2)(F):

" . . . except that with respect to a limited liability corporation, a direct corporate association does not exist if the entity holding more than 50 percent of the limited liability corporation may not and does not exercise control over the activities of the limited liability corporation, as evidenced by all of the following:

(i) Does not hold (and may not appoint or remove) more than 50 percent of the directors of the limited liability corporation;
(ii) May not appoint or remove officers of the limited liability corporation; and
(iii) May not act on behalf of the limited liability corporation or commit it to any obligation.

Evidence that an entity holding more than 50 percent of the limited liability corporation does not have the authority to exercise control over the activities of the limited liability corporation may be established through disclosure of the Operating Agreement of the limited liability corporation, and/or by a written attestation provided by an authorized officer of the entity that owns more than 50 percent of the limited liability corporation, affirming that the above criteria are met."

This proposed language, if adopted, would ensure that a "direct corporate association" relationship with an LLC is limited to those entities that have control (or that have the ability to control) the LLC based on objective, verifiable criteria. It is unreasonable for the ARB to conclude that a "direct corporate association" with an LLC exists if an entity cannot and does not exercise control over the activities or the governance of the LLC. (SHELL 3)

> **Response:** Thank you for the comment. ARB staff appreciates the concerns surrounding the definition of direct corporate associations for LLCs. Staff does not agree that the commenter's proposed modification would adequately ensure that all direct corporate associations involving LLCs are reported. Staff believes that the commenter's proposed modification is overly subjective and would omit LLCs wherein an entity may not appoint or remove officers of the LLC but may have the ability to recommend or influence officers. It is not the intent of section 95833(a)(2)(F) to cause inadvertent hardship and staff believes that section 95833(c) addresses some concerns surrounding the ownership of LLCs and will offer clarification in guidance. Staff also notes that no modifications to section 95833(a)(2)(F) were proposed in the 15-day language, so this comment is actually outside the scope of the amendments.

H-1.21. Comment: The first issue relates to the inclusion of the LLC as part of the direct corporate association. Shell, like other corporations with large compliance obligations, has concerns with the constraints that are being placed upon us in establishing the same holding limit for our aggregated account without regard to the size of the compliance obligation. However, an additional concern is the regulatory language that's being proposed that expands the definition of a direct corporate association to include an LLC. Shell maintains the position that an LLC is a specific legal entity having its own operating agreements and governance structure and that ownership of more than 50 percent is not a sufficient means to prove control. With respect to this end, Shell has provided staff with specific language that includes requirements for providing additional evidence of control that could be considered in making the determination. The proposed language includes additional objective and verifiable criteria that provides a superior test of control beyond a mere 50 percent ownership. While we have had some discussions with staff, this issue has not been resolved at this point. (SHELL 4)

> **Response:** Thank you for the comment. ARB staff appreciates the concerns surrounding the definition of direct corporate associations for LLCs and issues related to ownership and control. Staff does not agree that proposed modification would adequately ensure that all direct corporate associations involving LLCs are reported. Staff believes that the commenter's proposed text is subjective and would omit LLCs wherein an entity may not appoint or remove officers of the LLC but may have the ability to recommend or influence officers. It

is not the intent of section 95833(a)(2)(F) to cause inadvertent hardship and staff will work with stakeholders to address specific concerns in guidance.

H-1.22. Comment: The Staff proposes to include an LLC within the meaning of a “direct corporate association,” if an entity owns more than 50 percent of the LLC. As provided in previous comments, ownership of more than 50 percent of the LLC is not enough to establish a “direct corporate association” with an LLC. In order to determine the level of “control” that is required to establish a direct corporate association with an LLC in which an entity has an ownership interest, specific indicia of control must be considered, based on the terms of the LLC’s operating agreement and/or through an attestation by an authorized officer.

Shell Energy proposes that the ARB include the following language at the end of Section 95833(a)(2)(F):“ . . . except that with respect to a limited liability corporation, a direct corporate association does not exist if the entity holding more than 50 percent of the limited liability corporation may not and does not exercise control over the activities of the limited liability corporation, as evidenced by all of the following:

(i) Does not hold (and may not appoint or remove) more than 50 percent of the directors of the limited liability corporation;
(ii) May not appoint or remove officers of the limited liability corporation; and
(iii) May not act on behalf of the limited liability corporation or commit it to any obligation. Evidence that an entity holding more than 50 percent of the limited liability corporation does not have the authority to exercise control over the activities of the limited liability corporation may be established through disclosure of the Operating Agreement of the limited liability corporation, and/or by a written attestation provided by an authorized officer of the entity that owns more than 50 percent of the limited liability corporation, affirming that the above criteria are met.”

This proposed language, if adopted, will ensure that a “direct corporate association” relationship with an LLC is limited to those entities that have control (or that have the ability to control) the LLC based on objective, verifiable criteria. It is unreasonable for the ARB to conclude that a “direct corporate association” with an LLC exists if an entity cannot and does not exercise control over the activities or the governance of the LLC. (SHELL 3)

Response: Thank you for the comment. ARB staff appreciates the concerns surrounding the definition of direct corporate associations for LLCs and issues related to ownership and control. Staff does not agree that the commenter’s proposed modification would adequately ensure that all direct corporate associations involving LLCs are reported. Staff believes that the commenter’s proposed text is subjective and would omit LLCs wherein an entity may not appoint or remove officers of the LLC but may have the ability to recommend or influence officers. It is not the intent of section 95833(a)(2)(F) to cause inadvertent hardship and staff will work with stakeholders to address specific concerns in guidance.

Attestation

H-1.23. Comment: Language in Section 95912(4)(E), added in a previous regulatory amendment but not materially changed despite the concerns raised by BP and others, includes a requirement that entities who desire to participate in an auction provide "An attestation disclosing the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for that the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association , or indirect corporate association pursuant to section 95833 that participate in a car bon, fuel, or electricity market. The attestation must be updated to reflect any change in the status of an investigation that has occurred since the most recent auction application attestation was submitted;" When considered in light of the previously addressed issues on what may be thousands of corporate associations for large corporations such as BP, this requirement is wholly unworkable.
Virtually all large entities that have participated in commodities, securities or financial markets with millions of transactions across the globe are likely to have been subject to investigation for alleged violations. When combined with the regulation's requirement that the attestation also applies to what may be thousands of corporate associations, there will be virtually no way to track or report investigations that may have occurred in the distant past, perhaps before the entities were associated- with associations that may take place with entities all over the world.

BP strongly suggests that this section of the regulation apply only to ongoing investigations involving the entity participating in the auction, and not to a broad range of unrelated corporate associations, (i.e. removing the language in 95912(d)(4)(E) which reads and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833).(BP 2)

> **Response:** ARB staff respectfully disagrees that this section has not been materially changed. Relative to the initial language, staff added a 10 year time window for reporting and also changed the requirement to include only those corporate associates in carbon, fuel or electricity markets. With regard to restricting the provision only to on-going investigations, see the response to 45-day comments H-1.7. Moreover, while staff appreciates that the attestation disclosure imposes some additional work on auction participants compared to the requirements of the current Regulation, staff believes the information in the attestation disclosure is important to good market oversight and is good protection for all market participants. Staff is therefore not amenable to restricting the attestation disclosure to the entity participating in the auction as that would leave out corporate associates of the entity. As such, staff declines to implement BP's suggested changes to the regulatory text.

Auction Purchase Limit

H-1.24. Comment: Calpine strongly supports the 15-Day Changes' proposal to increase the auction purchase limit. Under the existing Regulation, the current vintage auction purchase limit for covered entities is15% of the allowances offered for auction at each auction occurring in 2013 and 2014. The Proposed Amendments would increase the current vintage auction purchase limit applicable to covered entities to 20% for the last auction in 2014.9 Calpine appreciates this proposal and urges CARB to finalize the Proposed Amendments at the earliest opportunity to assure the increase in the auction purchase limit becomes effective in advance of critical dates pertaining the November 19, 2014 auction (i.e., the auction notice date, auction application deadline and bid guarantee posting deadline). (CALPINE 4)

> **Response:** ARB staff appreciates the commenter's support for the increase in the purchase limit for the Current Auction.

H-2. Registration Requirements

General

H-2.1. Comment: 95830(f)(1): Please confirm whether the phrase "within 30 days of the changes becoming effective" in the first sentence of provision (f)(1) refers to 30 days after the board adoption date for the amendments in 95830(c) or 30 days after OAL approval of the amendment package (TESORO 3)

> **Response:** Section 95830(f)(1) requires entities to update their registration information within 30 days of the date when the changes in registration information are effective.

H-2.2. Comment: Section 95830(f)(1) modifies the timelines for updating registration information in a manner that promotes efficiency while maintaining market integrity. SDG&E and SoCalGas have proposed language to clarify the applicable timelines and have not proposed any substantive changes to Section 95830(f)(1):

(A) Registered entities must update their registration information as follows:
(B) The information identified in section 95830(c)(1)(A)-(G) and section 95830(c)(1)(J) within 30 calendar days after the changes become effective.
(C) The information identified in section 95830(c)(1)(H) for entities that are registered in the Cap-and-Trade Program within 30 calendar days after the changes become effective.
(D) The information identified in section 95830(c)(1)(H) for entities that are not registered in the Cap-and-Trade Program no later than the auction registration deadline established in section 95912 after the changes become effective.

The information identified in section 95830(c)(1)(I) no later than the auction registration deadline established in section 95912 after the changes become effective. (SEMPRA 4)

> **Response:** Thank you for the comment. ARB staff appreciates the timeline presented by the commenter, but does not believe that the regulatory text as modified in the 15-day changes sets forth a clear timeline for updating registration information and that no further modifications are needed.

Disproportionate Penalty for Noncompliance

H-2.3. Comment: In connecting proposed language in Section 95830(f)(3) with existing text in Section 95921(g)(3), ARB has created a disproportionate penalty for what may be an inadvertent error or omission by the registered entity. This amendment suggests that if changes to any of the information required by Section 95830(c) are made and an entity does not notify ARB within 30 days, the entity could have its registration revoked or suspended, which would result in a requirement to voluntarily retire or sell all of its compliance instruments contained in the holding account. For 2015, the holding limit is approximately 11.7 million allowances. The sale or voluntary retirement of nearly 12 million allowances has the potential to severely distort the compliance market, increase all market participants' compliance costs, and undermine the success of the Cap-and-Trade program. This penalty is extreme and should be removed from the regulation. (CCEEB 2)

H-2.4. Comment: PG&E supports the direction of proposed changes to Section 95830(c)(1)(I) as the language seeks to balance ARB's market monitoring efforts and the business operations of large compliance entities by tailoring the types of employees that must be reported to ARB. The proposed amendments require the name and contact information for all PG&E employees with knowledge of an entity's market position, which PG&E understands to be employees that have knowledge of both of the following:

- o Current and/or expected holdings of compliance instruments; and
- o Current and/or expected covered emissions

PG&E understands the term "holdings" to refer to the number of compliance instruments an entity has in each of its individual ARB account balances. To confirm this interpretation, and to facilitate compliance with the staff reporting requirement, PG&E requests the regulation define terms used by ARB. Specifically, PG&E recommends that ARB define "current holdings" and "expected holdings" and suggests the following language be added to Section 95802:

<u>"Current Holdings" means the account balances set forth in each of the entity's accounts contained in the tracking system.</u>
<u>Expected Holdings" means the account balances that will be in place in each of the entity's accounts contained in the tracking system after a transfer of allowances is made.</u>

PG&E appreciates the revisions made to Section 93830(f)(1), which generally provide entities the ability to update registration information within 30-calendar days of such change, or quarterly. However, in connecting proposed language in Section 95830(f)(3) with existing text in Section 95921(g)(3), ARB has created a disproportionate penalty for what may be an inadvertent error or omission by the registered entity. This amendment suggests that if changes to any of the information required by Section 95830(c) are made and an entity does not notify ARB within 30 days, the entity could have its registration revoked or suspended, which would result in a requirement to voluntarily retire or sell all of its compliance instruments contained in the holding account. For 2015, the holding limit is approximately 11.7 million allowances. The sale or voluntary retirement of up to 12 million allowances has the potential to severely distort the compliance market, increase all market participants' compliance costs, and undermine the success of the Cap-and-Trade Program. This penalty is extreme and should be removed from the regulation as follows:

95830(f)(3) ~~Pursuant to section 95921(g)(3)~~, ~~R~~registration for the next auction may be restricted if an entity does not update its registration as required in section 95830(f)(1)~~within 10 days of a change pursuant to section 95921(g)(3).~~ (PGE 4)

> **Response:** ARB staff does not agree that the definitions proposed in the comments are needed to clarify section 95830(c)(1)(I). Regarding the penalty for noncompliance outlined in section 95830(f)(3), updating registration information in a timely manner is critical to ensuring the integrity of allowance auctions as well as the broader allowance market. Timely updates of the information outlined in section 95830(c) are required to ensure the holding limits and auction purchase limits are upheld between corporate associations. Staff believes that the language in section 95830(f)(3) is appropriate.

H-2.5. Comment: IETA appreciates the modifications made to this section as written in the proposed amendments. The new language appears to provide a more specific definition of those employees that should be required to provide contact information for program registration, which is much more manageable to maintain. However, additional clarity is required regarding the term "holdings".
IETA understands the term "holdings" to refer to the number of compliance instruments an entity has in each of its individual ARB account balances in CITSS. To confirm this interpretation, and to facilitate compliance with the staff reporting requirement, the "holdings" term should be defined. (IETA 2)

> **Response:** ARB staff appreciates the concern regarding the term "holdings" and will consider issuing guidance to further assist entities comply with this requirement. The intent of the section is not to require disclosure of individuals casually aware or associated with issues related to compliance instruments or reported emissions but to identify employees that are responsible for compliance strategy by knowing both an entity's compliance instrument holdings and reported emissions, including future compliance instrument procurement strategy.

H-2.6. Comment: The added language in section 95830(c)(7) that requires account viewing agents to provide registration details to ARB seems unnecessary and onerous for individuals whose account access is already limited. By definition, an account viewing agent cannot transact, and can only review an account status. The level of detail required for registration in ARB's proposed amendments is not commensurate with an account viewing agent's responsibility.
Consider, also, that it may be common practice for multi-national companies to employ non-US residents as account viewing agents – employees who would not have US bank accounts. (IETA 2)

> **Response:** No changes were proposed to section 95830(c)(7) during the 15-day modifications. As such, these comments are outside the scope of the proposed amendments, so no response is required.

H-2.7. Comment: IETA appreciates modifications within the proposed amendments in Section 95830(f)(1) and (3) to extend the period of time from 10 to 30 days that an entity has to make changes to its registration information as listed in 95830(c).
However, the language in 95921(g)(3) that may force an entity that fails to update its registration information within 30 days to sell or voluntarily retire all of the compliance units in its holding account is a disproportionately harsh penalty for what could be a reasonable oversight in failing to update registration details. IETA recommends language be adjusted to clarify that only in the most extreme cases of negligence resulting in failure to update an entity's registration information, should an entity be forced to sell all units in its holding account. As currently written, the language in 95921(g)(3) provides the Executive Officer too much subjectivity, and presents an extreme risk to compliance entities. (IETA 2)

> **Response:** Thank you for the comment. Regarding the penalty for noncompliance outlined in section 95830(f)(3), updating registration information in a timely manner is critical to ensuring the integrity of allowance auctions as well as the broader allowance market. Timely updates of the information outlined in section 95830(c) are required to ensure the holding limits and auction purchase limits are upheld between corporate associations. ARB staff believes that the language in section 95830(f)(3) is appropriate and provides the Executive Office the latitude to address a wide variety of violations. The intent is not to issue disproportionally harsh penalties but to allow for a range of enforcement actions to fit a wide variety of violations.

Attestation

H-2.8. Comment: ARB added but did not materially change the requirement that entities that wish to participate in an auction provide an attestation as follows:
An attestation disclosing the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for that the entity participating in the auction, and all

other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 that participate in a carbon, fuel, or electricity market. The attestation must be updated to reflect any change in the status of an investigation that has occurred since the most recent auction application attestation was submitted;

Given the proposed change to the Disclosure of Corporate Associations described above, this new attestation provision would require Chevron, on a quarterly basis, to research all potential investigations involving over years 1,610 separate entities, many of which operate wholly outside of the United States/or may be majority owned and operated by an entirely different entity, meaning the relevant information may not be shared or known. This plainly creates an undue burden and potential for inadvertent non-compliance for any large, multi-national company like Chevron. In addition, contracts may exist that prohibit Chevron's disclosure of investigations that are pending review.

Chevron recommends that ARB limit the attestation to entities in a "for cause" or "as needed" approach for anything beyond the current regulatory language, and better focus the scope of the required attestation on the most relevant entities, i.e., those that are directly involved in the California cap and trade program, not every possible corporate association. Having the leeway to ask for additional information about other entities when the need arises can accomplish ARB's need to investigate unusual situations without burdening every compliance entity with reporting data that will very likely never be the subject of concern. This type of conditional data request would provide the ARB an efficient and effective means to gather data when needed.

Chevron further requests that ARB align its attestation requirements with the very similar SEC disclosure requirements that already apply to many of the companies who are active in the California cap and trade program. The SEC reporting guidelines are tested and established methods for providing government agencies with prompt notice of active, relevant compliance issues. (CHEVRON 6)

> **Response:** Stakeholder comments on the proposed 45-day amendments reflected concerns about the unlimited time frame which the attestation disclosure would cover and the value of information on old investigations. Staff therefore proposed 15-day changes to limit the attestation disclosure to a period of 10 years. The scope of the attestation disclosure with respect to corporate associates is now limited to markets most closely related to the Cap-and-Trade program: other carbon markets, electricity or fuel markets. The revised language makes clear that the attestation must be updated to reflect a change in the status of an ongoing investigation. This change is intended to simplify completing the attestation disclosure for subsequent auctions.
>
> ARB staff does not agree that the information contained in the attestation should be requested on an "as needed" basis. Having timely access to information pertaining to investigations is necessary for market oversight and collecting

information from individual entities would be overly burdensome. The attestation will ensure that information is collected from all entities to ensure parity regarding collected information.

Staff has consulted with the SEC in identifying information pertaining for market oversight and will continue to work with state and federal regulators on issues pertaining to information release and market oversight. As such, staff declines to make the changes requested by the commenter.

H-2.9. Comment: While CCEEB appreciates the changes to Section 95912(d)(5), the language contained in the proposed amendments could still bar an entity from participating in an auction if any changes are made to the information provided in an entity's auction application within 30-days of an auction. CCEEB recognizes that Section 95912(d) is intended to facilitate effective settlement of the auctions and support market monitoring, and is not intended to be overly burdensome. CCEEB proposes that 95912(d)(5) be further tailored to remove the possibility that changes beyond the entity's control could jeopardize auction participation. Specifically, a change to an item identified in the auction attestation, such as the opening of an investigation, is beyond the entity's control and such change should not bar an entity from participating in an action. Moreover, such a change does not impede ARB's ability to settle the auction or monitor the marketplace for attempted manipulation. CCEEB suggests the following minor revisions to Section 95912(d)(5) to achieve this objective:
An entity with any changes to the auction application information listed in subsection 95912(d)(4)(A)-(D) or subsection 95912 (d)(4) (F) within 30 days prior to an auction, may be denied participation in the auction. For the purposes of changes to indirect and direct corporate associations, this section only applies to those corporate associates with entities registered in the tracking system. (CCEEB 2)

Response: See response to 45-day comment H-1.7. Staff declines to make the suggested change in the regulatory text.

H-2.10. Comment: The proposed 15-day language consists of an attestation "disclosing the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for the entity participating in the auction... "

As written, the requirement is broadly written, does not have a materiality or knowledge qualifier and covers alleged violations. It would be very difficult for LADWP to obtain and attest to the information over the time period specified, due to staff turnover and especially if the investigation did not result in an actual violation. Also, in §95912(d)(5), any change, even though the change results in a determination of no violation, to an entity's auction application information could result in the entity being denied auction participation. LADWP believes that the proposed revision would unnecessarily disqualify entities from participating in an auction.

Thus, LADWP urges CARB to further limit the scope of the attestation to previous investigations in which a violation was determined. LADWP recommends that §95912(d)(4)(E) be amended to read as follows:

An attestation disclosing investigations that have occurred within the last ten years which resulted in violations of any rule, regulation, or law associated with any commodity, securities, or financial market for the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporation association pursuant to section 95833. (LADWP 3)

Response: The commenter raises three separate issues. ARB staff specifically included language related to alleged violations, instead of a violation or conviction, because ARB's efforts to monitor the allowance market will be enhanced if ARB staff know that an entity is being investigated for specific behavior that may affect the allowance market; for example, an attempt by an entity to engage in manipulative behavior in the electricity market may also affect its activities in the allowance market. Waiting until an alleged violation results in a conviction or has been settled may take several years and in the meantime, diminish ARB's market oversight. Information with respect to ongoing investigations and alleged violations should be at least as valuable as information related to closed investigations or legal resolution in the courts because the information is likely to be more real time. Staff therefore declines to make the suggested change in the regulatory text.

Second, the commenter is concerned about the lack of a materiality or knowledge qualifier and about the difficulty that it may face in obtaining the information requested in the attestation. However, the commenter does not offer any change in the text with respect to a materiality or knowledge qualifier. With respect to materiality, staff does not believe a defined threshold is necessary for its market monitoring purposes. A knowledge qualifier, to the effect that entities report what they have knowledge of, would defeat the purpose of the attestation disclosure. Staff appreciates that the attestation disclosure imposes additional work on auction participants compared to the requirements of the current Regulation, but staff believes the information in the attestation disclosure is important to good market oversight and is good protection for all market participants.

Third, the commenter is concerned about the possible denial of auction participation in Section 95912(d)(5). Staff reiterates its comments from the Initial Statement of Reasons: "The text in this section says '….may be denied participation in the auction.' Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word 'may' would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in Section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation."

Finally, in response to the commenter's (and other commenters') concerns on the issue of the attestation disclosure, staff intends to provide written guidance on the attestation disclosure; that guidance will give auction participants some examples about specific information to be included in an attestation disclosure. It is staff's intent that the attestation disclosure information be concise, logically organized and sufficiently complete that staff can research the matter further if that seems a worthwhile expenditure of limited staff time.

H-2.11. Comment: Revisions in the 15-Day Changes to section 95912(d)(5) recognize the overly restrictive constraints that the Proposed Amendments would have had on auction participation. As previously drafted, the restrictions that section 95912(d)(5) placed on an entity's ability to both operate its core businesses and comply with the Regulation were unduly burdensome, and in some instances, completely outside the control of the covered entity; business changes should not preclude a covered entity from purchasing or selling allowances in the auction. As set forth in the 15-Day Changes, entities need not fear that already-completed allowance transactions may be invalided due to changes that occurred within 15 days following the completion of an auction. NCPA also supports the revisions that reduce the scope of information that is subject to updating and that could potentially disqualifying a covered entity from participating in an auction due to changes 30 days prior to the auction.(NCPA 3)

Response: ARB staff appreciates the commenter's support for the 15-day revisions to Section 95912(d)(5) in which staff deleted the provision regarding changes 15 days post-auction to auction application information outlined in section 95912(d)(4).

H-2.12. Comment: At section 95912(d)(4)(E), ARB has proposed amendments to the attestation an entity is required to complete if it intends to participate in an auction. The attestation, as proposed, requires an entity to disclose the existence and current status of any ongoing investigation, or an investigation that has occurred within the last ten years, with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental or financial market with respect to the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association, that participate in a carbon, fuel, or electricity market.

While we understand why ARB may be interested in open investigations of the entity participating in an auction, it is unclear why ARB would require such information for investigations opened (and presumably resolved) within the past 10 years, or investigations of all other entities with whom the registered entity has a corporate association, direct corporate association, or indirect corporate association.
As SGEN has explained in prior comments, many of the participants in the Program (including SGEN) are subsidiaries of large corporations with corporate structures that

involve dozens or even hundreds of other affiliates and subsidiaries which operate largely independently from one another, but which are required by the Regulations to be identified as corporate associations even though these other affiliates have nothing to do with the Program. Many or most of these corporate associations may not have readily available access to information regarding the others with whom the only relationship they share is that of having the same indirect ultimate corporate parent. In some cases, affiliated companies are barred from having or obtaining the type of information ARB contemplates requiring by section 95912(d)(4)(E) due to information sharing prohibitions under the California Public Utilities Commission Affiliate Rules and Federal Energy Regulatory Commission Standards of Conduct. Additionally, many or most of the corporate entities in question are not registered in the Program, subject to the Regulations, within the jurisdiction of ARB, or located within California or even in the United States. The proposed language of 95912(d)(4)(E) is drastically overbroad and over-reaching, and will be at a minimum onerous to comply with for such entities and, at worst, impossible to comply with. Entities will be continuously at risk of not being able to participate in auctions, or risk misreporting or providing ARB inaccurate details under this attestation, which could be considered a violation of 95921(f)(2)(E), (F), or (D), or the affiliate compliance rules promulgated by state or federal agencies.

Thus, section 95912(d)(4)(E) should be revised to state as follows:
An attestation of the entity participating in the auction, disclosing the existence and status of any ongoing investigation of that entity with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market. (SEMPRA 3)

> **Response:** Section 95912(d)(4)(E) was revised during the 15-day comment period to take into account stakeholder concerns regarding the unlimited time frame which the attestation disclosure would cover and the value of information on old investigations. In the 15-day amendments, ARB staff limited the attestation disclosure to a period of 10 years. In addition, the scope of the attestation disclosure with respect to corporate associates is now limited to markets most closely related to the Cap-and-Trade program: other carbon markets, electricity or fuel markets. The revised language makes clear that the attestation must be updated to reflect a change in the status of an ongoing investigation. This change is intended to simplify completing the attestation disclosure for subsequent auctions.
>
> ARB staff does not agree with the commenter’s proposed modification to section 95912(d)(4)(E) because it would limit the attestation to the reporting of ongoing investigations but would not require entities to report the existence of prior investigations and would not allow for proper market oversight. Staff believes knowledge of the existence of investigations pertaining to emissions trading or related markets is vital to the oversight of the market and understanding the current, and past, relationships between entities. Staff does not believe that the attestation in any way impinges on existing state or federal statutes related to information release. In fact, section 95912(d)(4)(E) requires an entity to report

the existence and current status of any investigation within the last 10 years, but does not require the release of confidential or protected information. The attestation will help staff understand the primary and related markets and is necessary for effective market monitoring. Staff appreciates the concerns surrounding the release of information pertaining to investigations and will clarify the requirements of the attestation in guidance. ARB's regulations do not require a violation of CPUC or FERC rules.

H-2.13. Comment: As currently proposed, Section 95912(d)(4)(E) of the 15-Day Modifications would require entities applying to participate in an ARB auction to disclose "the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years" for market rule violations committed by an entity with which the participating entity shares a direct or indirect corporate association. SCE appreciates the ARB's attempts to clarify these rules in the 15-Day Modifications. However, requiring this disclosure is unreasonable because existing rules that govern affiliate conduct and standard corporate protocols for information disclosure could prohibit employees of the participating company from accessing this information. Many entities that participate in the ARB auctions, including investor-owned utilities such as SCE, operate as wholly-owned subsidiaries of parent companies, which may also own other commercial entities in whole or in part. These other subsidiary companies would fall under the ARB's definition of direct or indirect corporate associations as set forth in the Cap-and-Trade Regulation and, thus, would be included in the disclosure requirement in an auction application. However, affiliate conduct rules could prevent one subsidiary from knowing whether another subsidiary had been subject to a pending or completed legal investigations. Thus, the ARB cannot reasonably require that an entity applying to participate in the auctions to attest to potentially sensitive legal information that it may not have access to about its affiliated corporate entities. (SCE 4)

Response: Section 95912(d)(4)(E) was revised during the 15-day comment period to take into account stakeholder concerns regarding the unlimited time frame which the attestation disclosure would cover and the value of information on old investigations. In the 15-day amendments, ARB staff has limited the attestation disclosure to a period of 10 years. In addition, the scope of the attestation disclosure with respect to corporate associates is now limited to markets most closely related to the Cap-and-Trade program: other carbon markets, electricity or fuel markets. The revised language makes clear that the attestation must be updated to reflect a change in the status of an ongoing investigation. This change is intended to simplify completing the attestation disclosure for subsequent auctions.

ARB staff believes knowledge of the existence of investigations pertaining to emissions trading or related markets is vital to the oversight of the market and understanding the current, and past, relationships between entities. Staff does not believe that the attestation in any way impinges upon existing state or federal statutes related to information release between corporate associates. In fact, section 95912(d)(4)(E) requires an entity to report the existence and status of any investigation within the last 10 years, but does not require the release of confidential or protected information. The attestation will help staff understand the primary and related markets and is necessary for market monitoring. Staff appreciates the concern surrounding the release of information pertaining to corporate associates and investigations and will clarify the requirements of the attestation in guidance. The attestation is intended to address known actions only. ARB understands it may not be possible for an entity to know everything about its related entities.

H-2.14. Comment: CARB has proposed further modification of a provision in section 95912 that would require auction applicants to submit an attestation regarding previous or pending investigations. Whereas the earlier version would require the auction applicant to disclose investigation of any entity with whom the applicant has a corporate association, the proposed change would limit this to other entities with which the entity has a corporate association and that participate in carbon, fuel or electricity markets. Although we appreciate staff efforts to address stakeholder concerns regarding this disclosure requirement, that fact that the regulation casts such a wide net for corporate associations means that the limitation to other entities that participate in carbon, fuel or electricity markets will have little practical effect.

WPTF understands that CARB's objective in requiring such an attestation is to identify evidence of potential market manipulation. However, an ongoing investigation does not mean market manipulation has occurred. CARB should only be concerned with collecting information on actual convictions.

To address these concerns, and make compliance with this requirement feasible, we request staff to modify the investigation attestation so that it applies only to investigations that have resulted in a conviction and only to other entities with which the applicant has a direct corporate association and that participate in carbon, fuel or electricity markets, as follows:

An attestation disclosing the existence ~~and status~~ of any <u>conviction</u> ongoing investigation or an investigation that has occurred within the last ten years with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for that the entity participating in the auction, and ~~all~~ *any* other *entity* ~~entities~~ with whom the entity has a ~~corporate association,~~ direct corporate association, or indirect corporate association pursuant to section 95833 that participates in a carbon, fuel, or electricity market. The attestation must be updated to reflect any <u>conviction</u> ~~change in the status of an investigation~~ that has occurred since the most recent auction application attestation was submitted;, (WPTF 3)

Response: The commenter believes "the limitation to other entities that participate in carbon, fuel or electricity markets will have little practical effect." ARB staff respectfully disagrees, as it limits reporting only to those entities operating in the markets that most closely overlap the carbon allowance market and eliminates reporting for corporate associates in other markets.

Staff specifically included language related to alleged violations, instead of a violation or conviction, because our efforts to monitor the allowance market will be enhanced if we know that an entity is being investigated for specific behavior that may affect the allowance market; for example, an attempt by an entity to engage in manipulative behavior in the electricity market may also affect its activities in the allowance market. Waiting until an alleged violation results in a conviction or has been settled may take several years and in the meantime, diminish ARB's market oversight. Information with respect to ongoing investigations and alleged violations should be at least as valuable as information related to closed investigations or legal resolution in the courts because the information is likely to be more real time. Staff therefore declines to make the suggested change in the regulatory text.

H-2.15. Comment: PG&E proposes that modifications to Section 95912(d)(4) include knowledge and materiality qualifiers to the ongoing investigation disclosure requirement for auction participation. For large compliance entities, knowledge and materiality qualifiers are essential for an entity's ability to provide the requested representation in a timely fashion. Moreover, the attestation should be limited to material violations of law and identify regulatory agencies of interest to the ARB. A reporting entity should not have its auction results jeopardized due to a failure to report a minor administrative violation of a Commodity Futures Trading Commission (CFTC) rule connected to its energy purchases, which would likely not be important information for ARB to carry out its market monitoring efforts. In addition, the required attestation should pertain only to those investigations that are currently pending before applicable entities. PG&E recommends the following modifications to Section 95912(d)(4):
(E)~~(C)~~ An attestation disclosing to the best of the participating entity's knowledge the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years by the Securities and Exchange Commission or the Commodity Future Trading Commission with respect to any alleged material violation of any ~~rule, regulation, or~~ law associated with any commodity, securities, environmental, or financial market for ~~that~~ the entity participating in the auction, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 that participate in a carbon, fuel, or electricity market. The attestation must be updated to reflect any change in the status of an ongoing investigation that has occurred since the most recent auction application attestation was submitted; (PGE 4)

Response: As with staff's other responses to comments on section 95912(d)(4), with respect to materiality and knowledge qualifiers, staff prefers to evaluate internally the materiality of the information in the attestation disclosure. For the example offered by the commenter of a minor infraction of CFTC reporting rules, a one to three sentence description of the infraction should be sufficient for ARB staff to make the determination of whether the infraction is a concern from a market monitoring viewpoint. Also, as stated in the Initial Statement of Reasons, "Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word 'may' would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in Section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation."

A knowledge qualifier, to the effect that entities report what they have knowledge of, would defeat the purpose of the attestation disclosure. Staff therefore declines to make the suggested changes in the regulatory text.

H-2.16. Comment: ARB has revised Section 95912(d)(4)(E) to require that an auction participant provide information about the existence and status of ongoing investigations related to the entity seeking to participate in an auction as well as related to any entity in a corporate association:

"An attestation disclosing the existence and status of any ongoing investigation or an investigation that has occurred within the last ten years with respect to any alleged violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for the entity participating in the auction***, and all other entities with whom the entity has a corporate association, direct corporate association, or indirect corporate association pursuant to section 95833 that participate in a carbon, fuel, or electricity market.*** The attestation must be updated to reflect ***any change in the status of an investigation*** that has occurred since the most recent auction application attestation was submitted." (Emphasis supplied). CPEM submits that it may not be possible for some entities to meet this requirement, both because the auction participant may not have such information, and because provision of such information may violate a variety of laws or other agreements.

By way of example, consider a series of affiliations based on the following hypothetical corporate structure: "Multinational A" is a large multinational company that includes subsidiaries that own power utilities in Europe, and therefore participates in an electricity market. Multinational A purchases 75% of "Company B", a Brazil mining company. Company B purchases fifty percent of "Company C," an otherwise privately-held California company engaged in manufacturing with Cap-and-Trade compliance obligations that wishes to participate in an auction. Multinational A and Company C do not share any employees, officers or directors.

Under this scenario, CPEM submits that Multinational A has no duty to disclose to Company C whether Multinational A is or has been subject to any investigation regarding any "alleged violation," nor is it likely to do so. Moreover, disclosure by Multinational A of such information to Company C, and/or by Company C to the ARB, may be directly contrary to other disclosure laws. For example, if Multinational A were traded on the New York Stock Exchange, disclosure of an alleged violation, or of a change in status of an investigation of an alleged violation, could be deemed a violation of the Fair Disclosure Regulations promulgated by the Securities and Exchange Commission pursuant to Regulation FD.

CPEM also notes that many investigations are expressly undertaken pursuant to confidentiality agreements, information restrictions or other form of regulatory "gag" orders placed on the entity subject to the investigation by a regulating body. As such, a requirement that Multinational A inform Company C, or for Company C to inform the ARB of an investigation, may be impermissible even if no publicly traded companies are involved.

CPEM also requests that the ARB eliminate the term "alleged" from this regulation, or provide specific guidance as to when an "alleged" violation must be reported. Specifically, the ARB should confirm that there is no duty to report situations in which the investigation at issue is (1) generic and not specific to the entity in question; or (2) is preliminary in nature, such as through receipt of a staff questionnaire that does not represent action by any regulatory body.

Given these concerns, CPEM requests that the ARB modify its regulations to specify that the attestation requirement only applies to the participating entity itself, and not to any corporate associations. Alternatively, as an intermediate solution, the ARB could modify its regulations to limit the attestation requirement to the participating entity and known investigations of direct corporate associations, where allowable by law:
"An attestation disclosing the existence and status of any <u>known</u> ongoing investigation or an investigation that has occurred within the last ten years with respect to any ~~alleged~~ violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for the entity participating in the auction, and all other entities with whom the entity has a ~~corporate association,~~ direct corporate association~~or indirect corporate association,~~ pursuant to section 95833 that participate in a carbon, fuel, or electricity market <u>in the U.S. or a Linked Jurisdiction, where such disclosure can be made without violating law.</u> The attestation must be updated to reflect <u>public information concerning</u> any change in the status of an investigation that has occurred since the most recent auction application attestation was submitted."
In the event ARB declines to make either of these proposed changes, CPEM respectfully requests that Staff specify in the Final Statement of Reasons that an entity seeking to participate in an auction will not be liable, nor prohibited from auction participation, to the extent such entity fails to disclose the existence of investigations of which the entity is unaware and/or where such disclosure would be in violation of law or regulatory requirement. (CPM 2)

Response: Please see response to 15-day comment H-2.13 above.

H-2.17. Comment: IETA appreciates the change in the proposed amendments to the provision in section 95912(d)(4)(E) that removes language requiring that an entity participating in an auction (including all associated entities) submit an attestation indicating that it has never been subject to any previous or ongoing investigation regarding "any alleged violation of any rule, regulation, or law associated with any commodity, securities, or financial market, including a change in the status of an ongoing investigation". The new language requiring instead disclosure of the existence of any ongoing or previous investigation is much more reasonable. However, IETA would like to propose ARB include knowledge and materiality qualifiers to this section as well to ensure companies (particularly large companies) are able to conduct appropriate diligence and provide the required information in a timely fashion. For example, a utility would not want to violate the cap-and-trade regulation due to a failure to report a minor administrative violation of a CFTC rule connected to its energy purchases, which would likely be unrelated to the utility's cap-and-trade activities. (IETA 2)

Response: As with staff's other responses to comments on section 95912(d)(4), with respect to materiality and knowledge qualifiers, staff prefers to evaluate internally the materiality of the information in the attestation disclosure. For the example offered by the commenter of a minor infraction of CFTC reporting rules, a one to three sentence description of the infraction should be sufficient for ARB staff to make the determination of whether the infraction is a concern from a market monitoring viewpoint. Also, as stated in the Initial Statement of Reasons, "Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word 'may' would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in Section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation."

A knowledge qualifier, to the effect that entities report what they have knowledge of, would defeat the purpose of the attestation disclosure. Staff therefore declines to make the suggested changes in the regulatory text.

H-2.18. Comment: As we noted in previous comments, the requirement to keep accurate records for the past 10 years of investigations, at the risk of an audit or an enforcement action, is not reasonable. WSPA suggests the language in this section be changed to reflect that only on-going investigations are included – and then *only for the entities involved in the Cap and Trade Program or linked GHG programs* - rather than the whole panoply of commodities, or securities, that are not directly related to cap and trade programs. (WSPA 5)

Response: In response to stakeholder comments during the 45-day comment period, ARB staff added the 10 year requirement as part of the 15-day amendments. The commenter offers no alternative to a 10 year window or any rationale for a shorter window. Instead, the commenter recommends that only on-going investigations be included. Staff expects that, once this requirement has been in place for some time, new information in the attestation disclosure will effectively be on-going investigations with closed investigations older than 10 years omitted from the disclosure. Staff also restricted the reporting to corporate associates in the carbon, fuel or electricity markets based on comments on earlier versions of the proposed amendments. Staff recognizes this is broader than the commenter's suggestion that the entity and its corporate associates be involved in the Cap-and-Trade program or linked GHG programs. Staff believes that its broader definition covers the most relevant markets related to the Cap-and-Trade program and that these markets are the appropriate target for attestation disclosure as it relates to market oversight. Staff therefore declines the opportunity to make the suggested changes in the regulatory text.

H-2.19. Comment: Additionally Brookfield opposes the proposed modifications in Section 95912 that require auction applicants to submit an attestation regarding previous or pending investigations within the past ten years including other entities with whom the applicant has a corporate associate that participates in carbon, fuel or electricity markets. While we support the revised language that limits the extent of corporate associations from any entity the applicant has a corporate association with to corporate associations that participate in related commodity markets, this requirement is still overly broad, onerous and burdensome. Brookfield's concerns with this proposed language are as follows:

1. Covered entities may not have access to information on investigations that apply to their corporate associations and therefore shouldn't be expected to provide an attestation related to other corporate entities investigations
2. An open investigation doesn't mean market manipulation has occurred and CARB should only be provided the information if the auction participant is actually convicted. Knowledge of open investigations without information on the outcomes would provide little value to CARB.

Recommendation: Brookfield recommends Section 95912(d)(4)(E) be modified as follows: (BEM 2)

An attestation disclosing convictions ~~existence and status of any ongoing investigation or any investigation~~ that have occurred within the last ten years with respect to any ~~alleged~~ violation of any rule, regulation, or law associated with any commodity, securities, environmental, or financial market for the entity participating in the auction. ~~and all other entities with whom the entity has a corporate association, direct corporation association, or indirect corporate association pursuant to section 95833 that participate in a carbon, fuel, or electricity market.~~

Response: Staff agrees that an open investigation does not imply the occurrence of market manipulation. However, staff disagrees that this means the attestation disclosure should be restricted to convictions.

Staff believes knowledge of the existence of investigations pertaining to emissions trading or related markets is vital to the oversight of the market and understanding the current, and past, relationships between entities. Staff does not believe that the attestation in any way impinges upon existing state or federal statutes related to information release between corporate associates. In fact, section 95912(d)(4)(E) requires an entity to report the existence and status of any investigation within the last 10 years, but does not require the release of confidential or protected information. The attestation will help staff understand the primary and related markets and is necessary for market monitoring. Staff appreciates the concern surrounding the release of information pertaining corporate associates and investigations and will clarify the requirements of the attestation in guidance. Staff declines the opportunity to make the suggested changes in the regulatory text.

Auction Application and Changes to Registration Information

H-2.20. Comment: The proposed amendments modify section 95912(d)(5) providing that auction participation may be denied if an entity "has any changes to the auction application information listed in subsection 95912(d)(4) within 30 days prior to an auction." ARB further amended this section to note that changes to indirect or direct associations are not included, unless the corporate associations have entities registered in the tracking system.

The addition of the language reducing the scope of reporting to only entities also registered in the tracking system is an improvement which SGEN supports. However, this requirement remains burdensome to Program participants who are required to take many steps, and perform extensive due diligence, to ensure that it has informed ARB of any changes to its application information prior to the auction. Given the complexities that exist in large corporate structures, it is unreasonable to force entities that participate in the Program to be at constant risk of violation due to failure to report information that they have no ability to know or discover, in particular if the corporate associations in question are entities which are subject to the information sharing prohibitions under the California Public Utilities Commission Affiliate Rules and Federal Energy Regulatory Commission Standards of Conduct. As provided under the Regulations at section 95833(c), "Any registered entity subject to affiliate compliance rules promulgated by state or federal agencies shall not be required to disclose information or take other action that violates those rules."

Therefore, section 95912(d)(5) should be removed from the proposed amendments. If staff continues to recommend the proposed amendment, however, ARB should revise it as follows:
An entity with any known changes to the auction application information it submitted, listed in subsection 95912(d)(4), must report those changes to ARB no later than the auction registration deadline established in section 95912. An entity may not participate in the auction if it fails to report this information in a timely manner. For the purposes of changes to indirect and direct corporate associations, this section only applies to those corporate associates with entities registered in the tracking system. (SEMPRA 3)

Response: In the Initial Statement of Reasons regarding section 95912(d)(5), ARB staff wrote: "The text in this section says "….may be denied participation in the auction." Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word "may" would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in Section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation." Staff's position on the possible denial of participation in an upcoming auction has not changed, whether the information that has changed is with respect to the attestation disclosure or corporate structure and ownership information or corporate associations. In addition, staff notes that the following proposed text change, "An entity may not participate in the auction if it fails to report this information in a timely manner." leaves open to ARB's determination as to what is "timely." Staff prefers the certainty of a 30 day window to define "timely" for participants. Staff declines to make the suggested changes in the regulatory text.

Staff does not agree that section 95912(d)(5) is a violation of any state or federal prohibition on information sharing. The attestation does not require an entity to disclose any confidential information regarding any previous or ongoing investigation, merely the existence of any investigation and its current status. Staff will issue guidance to assist entities in complying with the requirements to section 95912(d)(5).

H-2.21. Comment: In Section 95912(d)(4)(E) of the 15-Day Modifications, the ARB revised auction application requirements to specify that the attestation associated with the application need only disclose the existence of any market investigations against the entity, rather than attesting to the absence of any such investigations. SCE applauds this change, which should provide compliance entities with more certainty regarding their ability to participate in the quarterly ARB auctions.

Recommendation: However, to give participating entities full confidence in the auction application process, SCE urges the ARB to add the following language (in **bold**) to Section 95912(d)(5) of the 15-Day Modifications:

An entity with any changes to the auction application information listed in subsection 95912(d)(4) within 30 days prior to an auction**, other than changes to the status of any investigation reported pursuant to subsection 95912(d)(4)(E) in which no conviction, penalties or fines have been assessed against the participating entity,** may be denied participation in the auction. For the purposes of changes to indirect and direct corporate associations, this section only applies to those corporate associates with entities registered in the tracking system.

SCE's proposed language will give market participants greater assurance that the ARB would not unreasonably deny an entity's application to participate in an auction based solely on the opening or status change of an investigation against that entity, absent any conviction or penalty being assessed. The ARB already employs strong existing controls around auction conduct and market monitoring; additional participation restrictions based on market investigations which may be completely unrelated to the entity's participation in the ARB allowance market would provide no incremental benefit to the proper functioning and security of the ARB auction process.

Without SCE's proposed language, there is an increased risk that major market players may be excluded from participating in the auctions due to their disclosure of a change in the status of an ongoing market investigation occurring near the date of the auction. This unnecessary control measure could encourage these market players to forego the quarterly allowance auctions in favor of secondary markets, which tend to have significantly lower liquidity and lack ARB oversight. As a result, this provision could end up raising compliance costs for all entities and crippling the functioning of the entire allowance market. (SCE 4)

> **Response:** ARB staff appreciates the support for the 15-day change to section 95912(d)(4)(E). Given the general tone of some of the comments regarding the attestation disclosure, staff believes that some participants have overlooked the potential beneficial effect of attestation disclosure of prior or ongoing investigations, and violations of regulatory rules in the financial markets, relative to ARB staff learning that there is an issue via the financial press or from other regulatory agencies. Staff understands the commenter's concern with the possibility that a change in the status of an investigation, which is largely determined by the regulatory agency conducting the investigation and not the entity, may result in the denial of the entity's participation in an upcoming auction. In the Initial Statement of Reasons, staff wrote the following with respect to section 95912(d)(4)(E): "Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word 'may' would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation." A change in the status of an ongoing investigation, particularly since it has already been disclosed in a prior auction application, would be evaluated on its merits by staff; for example, a decision by the regulatory agency to close the investigation with no further action would be highly unlikely to trigger a denial of auction participation by ARB staff. Finally, staff notes that the suggested change in the text, to the effect that "**in which no conviction, penalties or fines have been assessed against the participating entity**," could be interpreted to mean that when a change in the status of an ongoing investigation results in a conviction, penalty or fine, ARB staff should simply deny that entity's auction application for that auction without any further consideration. This is clearly not the staff's intent. Staff therefore declines to implement the suggested change in the regulatory text.

H.2.22. Comment: While PG&E appreciates the changes to Section 95912(d)(5), the language contained in the proposed amendments could still bar an entity from participating in an auction if any changes are made to the information provided in an entity's auction application within 30-days of an auction. PG&E recognizes that Section 95912(d) is intended to facilitate effective settlement of the auctions and support market monitoring, and is not intended to be overly burdensome. PG&E proposes that 95912(d)(5) be further tailored to remove the possibility that changes beyond the entity's control could jeopardize auction participation. Specifically, a change to an item identified in the auction attestation, such as the resolution of an investigation, is beyond the entity's control and such change should not bar an entity from participating in an action. Moreover, such a change does not impede ARB's ability to settle the auction or monitor the marketplace for attempted manipulation. PG&E suggests the following minor revisions to Section 95912(d)(5) to achieve this objective:

An entity with any changes to the auction application information listed in subsection 95912(d)(4) (A)-(D) or subsection 95912 (d)(4) (F) ~~or account application information listed in section 95830~~ within 30 days prior to an auction, ~~or an entity whose auction application information or account application information listed in section 95830 will change within 15 days after an auction~~ may be denied participation in the auction. For the purposes of changes to indirect and direct corporate associations, this section only applies to those corporate associates with entities registered in the tracking system. (PGE 4)

Response: ARB staff appreciates the support for the 15-day change to section 95912(d)(4)(E). Given the general tone of some of the comments regarding the attestation disclosure, staff believes that some participants have overlooked the potential beneficial effect of attestation disclosure of prior or ongoing investigations, and violations of regulatory rules in the financial markets, relative to ARB staff learning that there is an issue via the financial press or from other regulatory agencies. Staff understands the commenter's concern with the possibility that a change in the status of an investigation, which is largely determined by the regulatory agency conducting the investigation and not the entity, may result in the denial of the entity's participation in an upcoming auction. In the Initial Statement of Reasons, staff wrote the following with respect to section 95912(d)(4)(E): "Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word 'may' would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation." A change in the status of an ongoing investigation, particularly since it has already been disclosed in a prior auction application, would be evaluated on its merits by staff; for example, a decision by the regulatory agency to close the investigation with no further action would be highly unlikely to trigger a denial of auction participation by ARB staff. Finally, staff notes that the suggested change would not provide information regarding markets closely related to the carbon allowance market. Staff therefore declines to implement the suggested change in the regulatory text.

H-2.23. Comment: LADWP supports the deletion of the provision that any changes to an entity's auction application 15 days after an auction could result in the entity's participation in the auction. As LADWP expressed in its February 14, 2014 comment letter, this requirement would lead to unnecessary administrative burden as fifteen days after an auction, the entity would have already submitted its bid guarantee, participated in the auction, and in the case of a purchase of allowances, gone through the administrative task of ensuring that the required funds were transferred to CARB in a timely manner.

Recommendation: LADWP recommends that §95912(d)(5) be amended as follows such that any change in the status of an investigation per §95912(d)(4)(E) does not result in denial of auction participation as a change in status is out of the control of the entity:
"An entity with any changes to the auction application information listed in subsection 95912(d)(4)(A) through (D) or subsection 95912(d)(4)(F) within 30 days prior to an auction may be denied participation in the auction."

Similarly, with respect to Reserve Sales' intent to bid notification requirements, LADWP recommends §95913(e)(2) be amended as follows: *"An entity with any auction application information listed in subsection 95912(d)(4)(A) through (D) or subsection 95912(d)(4)(F) that changes 20 days prior to a reserve, may be denied participation in a reserve sale."* (LADWP 3)

Response: ARB staff appreciates the commenter's support for the deletion of the 15-day post-auction application information requirement. With respect to the commenter's suggested change to section 95912(d)(5), staff believes it is important for market monitoring purposes to be able to understand changes to existing and ongoing investigations in markets related to the carbon market. Moreover, in the Initial Statement of Reasons, staff wrote the following with respect to section 95912(d)(4)(E): "Staff does not intend to routinely deny auction participation on the basis of information in the attestation disclosure; if this were the intent, the word 'may' would instead read 'shall.' Staff will carefully evaluate the information in the attestation disclosure, along with any other changes to information in listed in section 95912(d)(4). A decision to deny auction participation would be informed by the staff's evaluation." A change in the status of an ongoing investigation, particularly since it has already been disclosed in a prior auction application, would be evaluated on its merits by staff; for example, a decision by the regulatory agency to close the investigation with no further action would be highly unlikely to trigger a denial of auction participation by ARB staff. As such, staff declines to make the requested changes. With respect to the suggested changes to section 95913(e)(2), staff reasserts its belief that requiring the disclosure of investigations is important for market monitoring purposes, and declines to make the requested change.

H-2.24. Comment: Calpine applauds CARB staff's elimination of provisions within the Proposed Amendments that would have potentially barred an entity from auction participation for changes occurring within 15 days after the auction or for changes in personnel occurring in the thirty day-period prior to the auction. Calpine also appreciates CARB staff's revisions so that changes in unregistered corporate associations may no longer disqualify an entity from auction participation; only those changes in corporate structure involving other registered entities may disqualify an entity from auction participation under the 15-Day Changes. Calpine believes these changes reflect a sensible resolution and should be adopted as part of the final rulemaking package.

Section 95912(d)(4) of the Regulation currently requires every auction participant to complete an auction participation application at least 30 days prior to each auction.18 The 45-Day Proposed Amendments would have expanded the list of information that must be provided under section 95912(d)(4) and added a new provision whereby "[a]n entity with any changes to the auction application information listed in subsection 95912(d)(4) or account application information listed in section 95830 within 30 days prior to an auction, or an entity whose auction application information or account application information listed in section 95830 will change 15 days after an auction, may be denied participation in the auction." In turn, the account application information listed in section 95830 would have been expanded by the 45-Day Proposed Amendments to include, among other things, disclosure of the "[n]ames and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings."

These proposed changes were problematic in three main respects. First, it was unclear how changes occurring in the 15 days after the auction could bar participation in the auction, once the auction had already occurred and the results have been certified by the auction administrator. Second, given the many individuals who may have access to information on Cap-and-Trade account balances in large companies and the probability that any one of them might be replaced in the thirty days before or fifteen days after an auction, it was highly likely that many of the largest auction participants would be susceptible to disqualification. Third, given the complex corporate structures of some auction participants, it made no sense to bar participation due to changes in corporate associations involving entities which were not also registered in the Cap- and-Trade Program.

The 15-Day Changes cure these problems and reflect a sensible approach that balances the interest in assuring the integrity of the auction results with the practical realities of running a large organization participating in the Cap-and-Trade Program. By only allowing changes in other registered entities to affect one's participation and no longer allowing changes in personnel to result in disqualification, the 15-Day Changes focus on those changes in corporate structure or personnel that might affect calculation of holding limits and auction purchase limits. Calpine appreciates and fully supports these changes. (CALPINE 4)

Response: ARB staff appreciates the commenter's support for the 15-day changes in the regulatory text and agrees that a change in corporate identity, structure or corporate associations could cause significant problems with the determination of auction purchase limits and entity holding limits.

Auction Dates

H-2.25. Comment: Revisions to Section 95910 provide the ARB with flexibility for the auction schedule to be adjusted. PG&E does not oppose this change, but requests that auction participants be provided with 30 days' notice prior to such change to accommodate auction preparation activities that may be impacted by such change. (PGE 4)

Response: Section 95910 reads that the auction dates in Appendix C may be adjusted by a maximum of 4 days. ARB staff intends to use this flexibility sparingly precisely because we recognize that this could impact pre-auction preparations by participants. While staff will do its best to provide as much advance notice as possible to potential auction participants of a change in the auction date, staff also believes the maximum of 4 days is not a significant burden for participants.

CITSS User Terms and Conditions

H-2.26. Comment: The CITSS User Terms and conditions should protect confidential information from public disclosure, and should place liability with WCI, Inc. for the proper functioning of the CITSS web platform.

As currently proposed in Appendix B of the 15-Day Modifications, the CITSS User Terms and Conditions are inconsistent with industry standards for website reliability and the confidentiality of user information. SCE agrees that it is important to specify up front the terms and conditions under which participating entities agree to use the CITSS. However, SCE objects to terms that risk the disclosure of confidential information and do not guarantee the reliability of the system. Such terms may force participating entities to choose between obeying their risk policies governing the use of Internet platforms or complying with the Cap-and-Trade Regulation, which provides for no alternative compliance mechanism outside of the CITSS.

The proposed language of the CITSS User Terms and Conditions provides inadequate safeguards around confidential information stored on the CITSS web platform by compliance entities and other users of the site. For example, the Terms and Conditions state that the ARB "may disclose Content to the public to the extent the disclosure is … [not prohibited] by California law," where Content is defined as "all information, data, text, or other materials that User provides to ARB or WCI, Inc. through use of CITSS." The proposed language thereby gives the ARB the discretion to release holding and compliance account balances held by compliance entities or other participants to the public. The release of this market-sensitive information to the public without a significant lag time (e.g., after the end of a compliance period) could encourage manipulation of the allowance market, as the public could gain insight into compliance entities' bid strategies and take advantage of any entity with a short position near the end of a compliance period.

Additionally, the CPUC Matrix of Allowed Confidential Treatment of Investor Owned Utility (IOU) Data protects the investor-owned utilities' net open position information as confidential due to its market-sensitive nature. Position information stored in CITSS is clearly protected by regulations promulgated by another State agency. In the ARB's current regulatory framework, CITSS is the only available mechanism for meeting compliance obligations. However, under Section 4.1 of the CITSS User Terms and Conditions, compliance entities are prohibited from seeking any legal damages against the ARB or WCI, Inc. arising from the failure of the CITSS platform. This provision is problematic because it appears to insulate the ARB and WCI, Inc. from liability if the CITSS platform were to fail and prevent compliance entities from meeting their compliance obligations in a timely manner. Thus, if the ARB levied penalties against a compliance entity for failing to meet a compliance obligation by a mandated deadline, even if the failure was a direct result of the CITSS platform malfunctioning, that entity would have no recourse against the operator of the platform. The current industry standard for user agreements involving Internet platforms includes an availability guarantee on the part of the platform operator of 99 percent availability or more. Not only does the ARB fail to make any such guarantee of the availability of the CITSS, it places the burden of economic harm on compliance entities in the event its Internet platform malfunctions. In order to better meet the applicable industry standard, the ARB should revise the liability provisions of the CITSS User Terms and Conditions to specify that WCI, Inc., as the creator and operator of the platform, will guarantee the availability of the CITSS platform to registered users at least 99 percent of the time, and that the ARB will postpone compliance deadlines in the event of a failure of the CITSS platform at any point during the 72-hour period preceding a compliance deadline. (SCE 4)

> **Response:** The contract requirements with the hosting provider stipulate that the CITSS should be available to users as much as reasonably practical, up to 24 hours a day. However, it may be necessary to schedule nightly or weekly down times for application maintenance. At a minimum, the application must be available no less than 18 hours per day with any scheduled downtime between 10pm and 4am PT. The CITSS has provided an overall availability of 99.56% since going live in August 2012. The lowest user availability recorded for any month of CITSS operations is 99.06% availability. Further, nearly all recorded "downtime" has been intentionally bringing the system offline for maintenance including systematic updates of security modules to stay ahead of evolving threats in the internet environment. The CITSS is designed to allow ARB to postpone processing of compliance deadlines as may be deemed appropriate in the event of the unavailability of the CITSS.

Know Your Customer Requirements

H-2.27. Comment: We do not believe that 10 days is enough time to provide the requested documentation associated with 95834(b). We request that ARB change this to 30 days similar to other registration and documentation requirements provided for in the regulation. (WSPA 5)

> **Response**: ARB staff does not agree that the text requires modification. Ten days is sufficient time for a user to resubmit the requested information and timely release of information is required for proper market oversight.

H-2.28. Multiple Comments: Section 95834(c)(2) continues to propose that the Executive Officer may re-verify all documents associated with Know-Your Customer (KYC) requirements every two years, which could require submittal of updated KYC registration documents from an individual registered in the program. Added clarity on why re-verification of KYC documents might be necessary would be appreciated, particularly as re-submittal of KYC documents may be quite onerous (bank account information, addresses, photo identification). Current regulatory language that requires re-submittal of information simply in the event that an individual's registration details change is preferable for IETA members. (IETA 2)

Comment: WPTF appreciates the modification to section 95834 so that resubmission of information for individual registered in CITSS is only required upon request of the Executive Officer for such information. However, we believe resubmission of information should only be required in exceptional circumstances, and not as a matter of standard practice. Additionally, it would be extremely useful for registered entities and individuals to understand the circumstances for which registration information for individuals will be required to be resubmitted. We therefore reiterate our request that CARB clarify and limit the conditions under which resubmission and re- verification of information would be required. (WPTF 3)

> **Response**: Users are required to provide updated information when registration details change. Re-verification of know-your-customer information will further ensure that ARB has accurate information about who is operating in the CITSS. Staff does not agree that section 95834 requires additional language as the current text allows the Executive Officer to use discretion in requesting the resubmission of information. Is it not the intent of this provision that this resubmission be overly burdensome or requested frequently, but staff believes the Executive Officer should have discretion in requesting the information.

H-3. Trading

H-3.1. Comment: The description of what should be entered as the Expected Termination Date set forth in Section 95921(b)(3) appears to contradict the definition of Expected Termination Date in Section 95802. The definition set forth in Section 95802(139) carves out contingencies, but 95921(b)(3)(B) inserts contingencies. To harmonize Section 95921(b)(3)(B) with the definition, PG&E proposes the following revision:

95921(b)(3)(B) Expected Termination Date of the transaction agreement. If completion of the transfer request process is the last term of the transaction agreement to be completed, the date the transfer request is submitted should be entered as the Expected Termination Date. If there are financial, contingency, or other terms excluding contingencies, to be settled after the transfer request is completed, the date those terms are expected to be settled should be entered as the Expected Termination Date. If the transaction agreement does not specify a date for the settlement of financial, contingency, or other terms that would be completed after the transfer request is completed, the entity may enter the Expected Termination Date as "Not Specified." (PGE 4)

> **Response:** ARB staff disagrees with the comment. Staff believes that in practice there will be no consistency problems because either (1) the terms to be settled after the transfer is completed will have a date that can be used as the Expected Termination Date, or (2) the entity may enter the Date as "Not Specified."

H-3.2. Comment: Over-the-Counter Sales of Compliance Instruments (S95921(b)(3)(A) and (B) and 95921(b)(4)(A) and (B)). These sections require that a transfer request for an over-the-counter agreement for the sale of compliance instruments must include the dates on which the agreement was entered into and terminated, and the transfer was scheduled. The information has no bearing on the integrity of the trading process. WSPA recommends ARB delete these requirements. (WSPA 5)

> **Response:** Sections 95921(b)(3)(A) and (b)(4)(A) are identical to the existing requirements. Sections 95921(b)(3)(B) and (b)(4)(B) replace the existing requirement to enter a date of settlement of the transaction agreement with an expected termination date of the transaction agreement. This change was made during the 15-day amendments in response to comments from many account representatives that the term "settlement date" was confusing.
>
> These proposed requirements are not fundamentally different than the existing requirements in sections 95921(b)(4) and (5), other than that they are made specific to over-the-counter transactions. As ARB staff has explained in workshops and previous rulemakings, these two data fields allow ARB staff to evaluate market prices by (1) understanding when agreements were signed and prices determined, and (2) whether agreements involve multiple transfers or multiple products.

H-3.3. Comment: §95921(b)(3)(C) and 95921(b)(4)(D), (E), (F) and (G). These sections require disclosure of the price of compliance instruments, transfers of products, and the pricing method. The auction settlement price and the reserve auctions are the best indicators of price containment. Reporting of over-the-counter transfer prices to

CITSS will not provide added value to the market. WSPA recommends ARB delete these requirements. (WSPA 5)

> **Response:** The commenter objects to a price disclosure requirement which is contained in the existing requirements in section 95921(b)(6). The argument that auction results are sufficient indicators of price containment is incorrect. If markets become tight after an auction, the prices reported as part of the transfer requests will be the only reliable indicator of market conditions. There are few market reports of over-the-counter trades and the market has no way to evaluate their reliability and coverage. Failing to require price disclosure would limit ARB's ability to detect market problems or enforce market rules.

H-3.4. Comment: General Prohibitions on Trading (S95921(f)). ARB has proposed language that prohibits an entity from holding allowances for another entity that has ownership interest in those allowances, unless the entities share a direct corporate relationship. While such a requirement is understandable to ensure that a bank does not hold allowances for an industrial entity in order to get around a holding limit, the language is not clear enough to allow direct and indirect entities to hold allowances for each other. The ownership issue and financial interests could become muddy due to corporate structures.

WSPA is concerned with the trade restrictions and market complexity introduced in the proposed amendments. These proposed restrictions will eliminate critical transactions such as options, futures, forwards and right-of-first-refusal contracts. These types of transactions promote a robust and efficient market structure. As we indicated earlier in these comments, WSPA understands the agency's need to identify "bad actors", but rules must be designed so that honest parties are able to avoid inadvertent missteps. ARB should provide guidance similar to that issued for resource shuffling that explains specific safe harbors or specific examples of "bad behavior". This is needed in the rulemaking to provide some measure of definition to allow regulated parties to understand the limits or boundaries that ARB intends to enforce.

Prohibitions on trading are overly broad and should be curtailed to permit legitimate transactions that support program objectives and create liquidity. For example, requiring that "an entity cannot acquire allowances and hold them in its own holding account on behalf of another entity" could be interpreted to interfere with the ability of entities to purchase allowances from market makers at auction prices.

ARB should provide a safe harbor for forward contracts under the trading prohibition. The new proposal includes additional language that deviates materially from the guidance provided by ARB in December of 2012. The new proposal uses very broad language that could be read to mean the safe harbor is practically inaccessible. This language needs to be scaled back to be consistent with the December 2012 guidance. Additionally the beneficial holdings provisions do not allow escrow arrangements because by definition, such arrangements involve a holding on behalf of another. Escrow is a fundamental component of corporate transactions and this could create unnecessary obstacles to numerous corporate transactions involving covered entities. We support the addition of a safe harbor for escrow accounts, in addition to the safe harbor for forward contracts and for holding allowances between direct and indirect corporate associations.

WSPA recommends ARB adopt the language regarding forward contracts consistent with the December 2012 guidance and take a similar approach for escrow accounts and transactions between direct and indirect corporate associations. We further recommend that ARB delete the proposed changes to "Prohibitions on Trading" requirements. (WSPA 5)

> **Response:** ARB staff disagrees with the assertion that the prohibition on holding on behalf of another entity is confusing when members of a direct corporate association are involved. The regulation provides an explicit exemption for members of a direct (not indirect) corporate association in section 95921(f)(1)(C). The regulation text contains a clear definition of direct corporate association. Since entities must document for ARB the existence of these associations when they register or when a direct corporate association is subsequently created, there will be no confusion when transfers are processed. ARB allows the holdings for members of direct corporate associations because the level of control associated with direct corporate associations is high enough that ARB presumes the entities coordinate all market activities. Consequently, the regulation has other restrictions on members of a direct corporate association that limit their potential market power that do not apply to members of an indirect corporate association.
>
> Staff does not understand the assertion that the proposed amendments would eliminate the use of futures, options, or forward contracts. The amendments explicitly include the reporting of transfers that result from settling futures contracts, along with exchange-traded options on futures contracts. ARB staff has stated in numerous workshops and regulatory guidance documents, including this Final Statement of Reasons, that the proposed changes will not interfere with commonly-used forward contracts. Indeed, staff has observed many such contracts in practice and has confirmed with account representatives that the process is understood and gives them sufficient flexibility. Staff is not aware of any registered entities trying to use right-of-first-refusal contracts. The issues would depend on the specific terms of such agreements.
>
> Staff agrees with the commenter's suggestion that ARB provide further guidance on which practices conform to the new requirements. Indeed, some of the proposed changes place into regulation text the explanations currently contained in guidance.
>
> Staff disagrees with the assertion made in the comment that the explanation contained in section 95921(f)(1)(A), (B), and (C) of the existing requirement in section 95921(f)(1) prohibiting holding on behalf of another entity are overly

broad and would prevent purchases on the secondary market at prices based on auction settlement prices. Staff has observed a number of forward agreements in which pricing is based on an auction settlement price and a margin. That is why staff explicitly included this pricing method in the price reporting section for longer-term over-the-counter agreements.

Staff is aware that some entities are interested in escrow arrangements, but ARB has not had interaction with account representatives actively trying to use such arrangements, other than the use of forward agreements meeting the proposed regulation criteria. Staff is interested in working with stakeholders on this issue for future revisions.

H-3.5. Comment: We share staff's desire to avoid market manipulation that could result from one entity inappropriately holding allowances for another entity. However, in discussions with staff, it is our understanding that this prohibition is not intended to apply to associated entities who properly report their association and who are therefore subject to a single holding limit. The current language could be amended to more clearly identify what is prohibited and what is allowed. More specifically, the language which allows for holding of allowances by/for associated entities in (f)1(C) currently resides under "restrictions" on holding allowances. The language should be amended to make clear that (f)1(A) does not supersede or override (f)1(C). An example of such an amendment is below:

(1)The ability for one entity to acquire allowances and hold them in its own holding account on behalf of another entity are limited as following:
(A) An entity may not hold allowances in which a second entity has any ownership or financial interest unless the second entity is disclosed as a corporate association under section 95833 or unless that second entity is an affiliated entity which is not a covered entity and/or not qualified to be an opt-in covered entity or voluntarily associated entity.
(B) An entity may not hold allowances pursuant to an agreement that gives a second entity control over the holding or planned disposition of allowances while the instruments allowances reside in the first entity's accounts, or control over the acquisition of allowances by the first entity. The se prohibitions do not apply to agreements that only specify a date to deliver a specified quantity of allowances and that include no terms applying to allowances residing in another entity's account or to holding of allowances by or for corporate associations disclosed in section 95833 or to an affiliated entity which is not a covered entity and/or qualified to be an opt- in covered entity or voluntarily associated entity. (BP 2)

Response: ARB staff appreciates the concern expressed in the comment, but does not agree that the text can be read such that section 95921(f)(1)(B) would override section 95921(f)(1)(C). Staff separated the prohibition in section 95921(f)(1)(B) from the exception granted to members of a direct corporate association in section 95921(f)(1)(C) specifically to clarify the exemption. No further clarification is needed.

H-3.6. Comment: The 15-day changes propose the following new definitions (with emphasis added):

- "Expected *Settlement* Date is a date specified in a transaction agreement on which all requirements in the transaction agreement are expected to be *settled,* exclusive of any contingencies specified in the agreement."
- "Expected *Termination* Date is a date specified in a transaction agreement on which all requirements in the transaction agreement are expected to be *completed,* exclusive of any contingencies specified in the agreement."

  The only difference between the two definitions is that "Expected Settlement Date" uses the word "settled" whereas "Expected Termination Date" uses the word "completed" with respect to the requirements to a transaction agreement. It is not clear what the difference between settling versus completing an agreement is or why GARB decided to develop two distinct definitions for what appears to be the same action. LADWP requests that either the two definitions be merged with additional language to define what "settled" or "completed" means or that the difference between the two definitions be explicitly explained in the definitions themselves.(LADWP 3)

> **Response:** The two definitions are needed even though they appear quite similar due to the need to update the CITSS to accommodate the new transfer request information requirements. Staff expects the regulation to be effective by July 1, 2014 but CITSS cannot be updated until January 1, 2015. Between these two dates the regulation must use the terminology currently employed in the regulation and the CITSS screens. The definitions are similar as they incorporate explanations of settlement date currently posted in the online guidance document. ARB staff is changing the terminology from settlement date to termination date for clarity but cannot make the change effective in regulation before it can be changed in CITSS.

H-3.7. Comment: LADWP also recommends that CARB monitor the holding limit issue closely to determine if it should be increased and/or if other mechanisms should be in place (e.g. allowing entities to surrender compliance instruments at any time) to ensure that the holding limit is not a barrier for an entity's compliance with the cap-and-trade regulation. (LADWP 3)

> **Response:** These comments are outside the scope of the proposed 15-day amendments so no response is required.

H-3.8. Comment: SGEN appreciates the efforts ARB intends to undertake to tailor CITSS to account for all possible transfers that could potentially occur in an entity's account, but the proposed amendments to section 95921(a) and (b) are unnecessary, confusing to Program participants, and overly burdensome.

The Regulations, as proposed, remove the requirement at 95921(a)(l)(E) that, "the completed transfer request must be received by the accounts administrator no more than three days following the day of settlement of the transaction agreement for which the transfer request is submitted," and introduces varying requirements at 95921(a)(3) and (4) making "the parties to a transfer" in violation of these sections if transfers are not processed within the specified time periods. Not only will these amendments cause confusion over the "initial submission date" and "expected settlement date," but these amendments imply that if this requirement is not met, it is the parties to the transfer that have violated the Regulations, even though the negligence of one party cannot be reasonably controlled by the other party. This would obviously be wholly unfair.

Sections 95921(a)(3) and (4) should be removed from the proposed Regulations and the language at 95921(a)(1)(E) reinstated. Amended section 95921(i)(l)(C) and (D) should be revised further to eliminate the reference to 95921(a)(1)(C), (a)(3), and (a)(4), and should reference only the timing requirement under 95921(a)(1)(E). If ARB agrees to make the changes SGEN recommends here, the proposed definitions of "Expected Settlement Date," "Expected Termination Date," and "Over-the-Counter" should not be added to section 95802(a) at subsections 138, 139, and 260 because they will not be needed. (SEMPRA 3)

> **Response:** ARB staff disagrees with the assertion made in the comment that the proposed changes are new and burdensome compared to the existing requirements, since they represent minor clarifications of existing requirements. In addition, the proposed changes do not change the responsibilities of the two parties to complete the process within the prescribed time that exist under the current regulation.
>
> The proposed addition of new text to section 95921(a)(3) through 15-day amendments makes existing requirements, including those in existing section 95921(a)(1)(E), effective for the period from July 1, 2014 through December 31, 2014. The main purpose of the change is to clarify the existing requirements. The proposed changes to section 95921(a)(4) make the requirements effective January 1, 2015 and replace the “expected settlement date” with “expected termination date.” ARB is proposing this change in response to extensive stakeholder discontent with the term “settlement.” The multiple effective dates of these provisions are necessary because the replacement provisions cannot be integrated into CITSS until January 1, 2015 and the existing requirements needed clarification.
>
> The changes in definitions in section 95802 referred to in the comment are still needed.

H-3.9. Comment: The proposed amendments to section 95921(b) would require entities to provide potentially proprietary information regarding transactions with an unreasonable level of detail given the very limited timeframe in which all involved parties must review and approve a transfer. This short timeframe puts transferring entities at risk of either missing a transaction completion deadline, or providing ARB inaccurate details of a transaction which could be potentially viewed as false or misleading, and

therefore a violation of 95921(f)(2)(E), (F), or (D). It should be noted that many of the trades that represent transfers in and out of CITSS accounts are transactions which are subject to U.S. Commodity Futures Trading Commission reporting requirements, and the details of the transactions (settlement price for example) is readily available via ICE and other exchanges. Given the limited role of ARB in these transactions, it is more appropriate that ARB utilize its current right to request the underlying contracts for the transactions should additional market monitoring information be desired.
The language of section 95921(b)(1) through (7) in the currently effective Regulation should remain effective, and the suggested modifications to 95921(b) and (c)(l) through (5) in this 15- day version should not be approved.

The language of section 95921(b)(1) through (7) in the currently effective Regulation should remain effective, and the suggested modifications to 95921(b) and (c)(l) through (5) in this 15- day version should not be approved. (SEMPRA 3)

Response: ARB staff disagrees with the assertion made in the comment that the level of detail of information to be submitted with a transfer request is unreasonable "given the very limited timeframe in which all involved parties must review and approve a transfer." In the case of Intercontinental Exchange (ICE) futures contracts that go to settlement, all of the information ARB is proposing to require entities to submit is provided to the entities by the ICE member clearing entities. Entering this information into CITSS takes minutes and is not burdensome. For other types of transaction agreements, ARB designed the information requirements around what staff has observed in agreements that have resulted in transfers. The intent is to gather information contained in the agreements, which means the burden would generally consist of copying information from the agreement into the CITSS transfer form. ARB has also recognized that much of the information contained in the transfer requests is confidential business information, which is why ARB has agreed to protect such information to the extent possible under existing section 95921(e).

Staff also disagrees with the assertion that requiring information on futures transactions is unnecessary and that because some data is available from ICE on futures transfers the requirements should be dropped for non-futures transactions as well.

Finally, ARB disagrees with the recommendation that staff should rely on calling in transaction agreements rather than requiring data through the CITSS transfer requests. ARB has utilized its authority to call in transaction agreements in numerous cases. In some cases ARB has done this as a quality control to ensure data reporting requirements are met, but in most cases staff initiated requests based on issues identified from the information submitted with the transfer request. There are also cases in which staff requested agreements in response to a question from an account representative who needed explanation of how to enter the transfer request data. In most of the latter cases, account representatives have indicated it is easier for them to correctly enter data rather than have ARB request the agreements. As such, ARB staff declines to make the requested changes.

H-3.10. Comment: WSPA continues to be concerned that the current holding and purchase limits are extremely restrictive. The outcome will likely be a constrained market that limits participants' flexibility to comply at the lowest incremental cost. The conservatively low holding/purchase limits disproportionately impact those entities with large compliance obligations, particularly those sharing holding limits and purchasing limits with one or more directly related entities. Furthermore, this problem will be compounded in 2015, since the compliance obligations of fuel providers are typically much higher than the increase in the holding limit. These constraints leave such an entity no alternative other than to prematurely move large quantities of compliance instruments to its compliance account, rendering useless the multi-year compliance period flexibilities and exposing the company to significant risks of stranded assets in the event of operational or corporate activity changes over the compliance period.
As you are aware, the Emissions Market Assessment Committee (EMAC) recognized these concerns in its November 8, 2013 report and offered two possible recommendations: 1) consideration of adjusting or scaling the holding/purchase limits based upon the compliance obligation for a particular entity and 2) consideration of additional flexibility in movement of compliance instruments from the compliance account, including allowing a portion of the compliance instruments to be removed and offered for resale into the market. The opinion of the EMAC was that making these modifications would provide additional flexibility to the regulated entity, while still preserving the goal of preventing market manipulation.

ARB should consider for adoption the recommendations prepared by the EMAC. ARB should place specific emphasis on scaling of holding/purchase limits that reflects the size of the entity's obligation, and provides increased flexibility and control by the regulated entity with respect to management of the accounts. (WSPA 5)

Response: These comments are outside the scope of the proposed 15-day amendments so no response is required.

H-3.11. Comment: Section 95921(f)(1) of the Cap-and-Trade Regulation currently prohibits an entity from acquiring and holding allowances in its own holding account on behalf of another entity. As Calpine suggested when this section was initially proposed, this provision could be interpreted to prohibit an entity from ever acquiring allowances on behalf of another entity, including under common arrangements between utilities and power suppliers to account for the compliance obligation associated with dispatch pursuant to a power or steam sale contract. CARB subsequently published guidance that clarified that the prohibition was not intended to apply to such arrangements between utilities and their contractual counterparties.

The 45-Day Proposed Amendments, however, would have complicated things by requiring that lawful contracts "only specify a date to deliver a specified quantity of allowances and [] include no terms applying to allowances residing in another entity's account."12 In so doing, the 45-Day Proposed Amendments could have been interpreted to outlaw many standard form contracts used by investor owned utilities ("IOUs") to account for GHG allowance costs. The 15-Day Changes delete this requirement and instead provide that "[p]rovisions specifying a date to deliver a specified quantity of compliance instruments, or specifying a procedure to determine a quantity of compliance instruments for delivery and/or a delivery date,do not violate the prohibition."

This should address the concern that many common utility-generator contracts might run afoul of the 45-Day Proposed Amendments because they include many other terms governing the parties' respective obligation with respect to procurement and transfer of allowances, beyond merely the quantity of allowances to be delivered and date of delivery.

While Calpine appreciates CARB's proposed revisions to section 95921(f)(1)(B) and believes they should resolve uncertainty as to the legality of common utility-generator contractual arrangements, we would urge CARB to clarify its intention in this respect in the Final Statement of Reasons for the Proposed Amendments or in stand-alone guidance. (CALPINE 4)

> **Response:** ARB staff appreciates the concerns as well as the support contained in the comment. ARB has worked with a large number of stakeholders to understand the wide range of contract types used by generators of power products, such as electricity or steam. Staff intends section 95921(f)(1)(B) to address transaction agreements in which the purchasers agree to transfer to a power generator sufficient compliance instruments to cover the emissions obligation from the generation. In these transactions, the amount of power to be obtained is not known at the time the transaction agreement is signed. Therefore, these contracts do not always specify a fixed price or quantity, and sometimes not even a schedule for transferring the compliance instruments. They usually contain terms that the parties will follow in establishing the quantities, prices, and time of transfer.
>
> ARB staff proposed the initial language in section 95921(f)(1)(B) to prohibit what are known as beneficial holdings. These are agreements between two parties in which one party agrees to keep compliance instruments in its account that actually belong to another entity or over which another entity has control over disposition. Allowing this activity would make market monitoring and enforcement of the holding limit nearly impossible. Staff added language in the 15-Day public notice to clarify that the prohibitions do not apply to the types of transaction agreements described in the previous paragraph. These agreements do not grant the generator any control or interest in the compliance instruments while they reside in the power purchaser's account. In this way they are a form of forward agreement that only commits one entity to deliver a quantity of compliance instruments to another entity at an agreed upon price and date. The fact that the transaction agreement only contains a procedure for determining the

quantity, price and date does not change its status as an acceptable forward agreement.

Implications to Limited Exemptions

H-3.12. Comment: The Cap-and-Trade Regulation contains a limited exemption from the holding limit, which is the number of allowances exempt from the holding limit calculation after they are transferred by a covered entity to its compliance account. The 45-Day Proposed Amendments would have replaced the existing provisions with a new provision that would only begin calculating the limited exemption on October 1, 2014 (based on emissions in the 2012, 2013 and 2014 emissions data reports receiving a positive or qualified verification statement).

The problem with the Proposed Amendments was that, assuming they should go into effect on any date prior to October 1, 2014, covered entities would have no limited exemption as of that date and could unwittingly be thrown into noncompliance with the holding limit. Section 95920(d)(2)(B) of the 15-Day Changes cures this problem and should assure thereby assure that no such inadvertent violations of the holding limit occur. Calpine appreciates CARB staff's work to close this potential and unintended gap in the limited exemption. (CALPINE 4)

> **Response:** ARB staff appreciates the concern expressed in the comment. The 45-day text did not reflect a change in the planned effective date from October 1, 2014 to July 1, 2014. Staff agrees that the revised 15-day amendment prevents the problem.

H-3.13. Comment: IETA's previous stakeholder comments raised concerns with the definitions of "futures" and "spot" contracts, and extending from those definitions, the reporting requirement to distinguish between futures and spot contracts in section 95921(b)(5)(C). The proposed amendments eliminate "futures" and "spot" contract language completely, thereby assuaging IETA's concerns.

Further, IETA very much appreciates staff adjusting the "Over-The-Counter" definition to: "the trading of carbon compliance instruments, contracts, or other instruments not executed or entered for clearing on any exchange."

IETA supports the change originally appearing in the discussion draft section 95921(b)(1)(B) removing the requirement that the seller of units in a transaction must need to know the "… identification of a primary account representative or alternative account representative for the destination account confirming the transfer request, if confirmation of the transfer request is required."

IETA supports the change in the proposed amendments section 95921(a)(4) that provides added clarity that written or recorded oral agreement may constitute a transaction agreement. (IETA 2)

Response: Thank you for the support.

H-3.14. Comment: IETA appreciates the addition in the proposed amendments allowing for the listing of an expected settlement date in transactions where the settlement date is not fixed and may be subject to floating dates or dates triggered by other events. Additional clarity would be useful pointing out that if an expected settlement date happens to change, ARB will not hold the reporting entity liable. (IETA 2)

Response: ARB staff appreciates the concern and will further address the question in guidance. The dates and other information to be placed in the transfer agreement should be entered into CITSS as they are contained in the transaction agreement at the time the transfer request is submitted. Staff has observed that when agreements are changed, such as for extensions or early terminations, there are usually new agreements that point back to the transaction agreements in effect when the transfer is submitted. These documents usually make it easy for staff to correctly evaluate compliance.

H-3.15. Comment: IETA supports the changes allowing for an expected termination date, however the use of this term is inconsistent within the proposed amendments. The description of what should be entered as the Expected Termination Date set forth in Section 95921(b)(3) contradict the definition of Expected Termination Date. In particular, the definition set forth in Section 95802 carves out contingencies, but 95921(b)(3)(B) inserts contingencies. To harmonize Section 95921(b)(3)(B) with the definition, IETA suggests the following revision:

95921(b)(3)(B) Expected Termination Date of the transaction agreement. If completion of the transfer request process is the last term of the transaction agreement to be completed, the date the transfer request is submitted should be entered as the Expected Termination Date. If there are financial, contingency, or other terms excluding contingencies, to be settled after the transfer request is completed, the date those terms are expected to be settled should be entered as the Expected Termination Date. If the transaction agreement does not specify a date for the settlement of financial, contingency, or other terms that would be completed after the transfer request is completed, the entity may enter the Expected Termination Date as "Not Specified." Similarly to the settlement date issue above, IETA also requests confirmation that if an expected termination date happens to change, that ARB will not hold the reporting entity liable. (IETA 2)

Response: ARB staff appreciates the concerns expressed in the comment. On the question of consistency between the definition and the text, staff believes that in practice there will be no consistency problems because either (1) the terms to be settled after the transfer is completed will have a date that can be used as the Expected Termination Date, or (2) the entity may enter the Date as "Not Specified."

On the question of compliance when dates or other facts change after a transfer is completed, the dates and other information to be placed in the transfer agreement should be entered into CITSS as they are contained in the transaction agreement at the time the transfer request is submitted. Staff has observed that when agreements are changed, such as for extensions or early terminations, there are usually new agreements that point back to the transaction agreements in effect when the transfer is submitted. These documents usually make it easy for staff to correctly evaluate compliance.

H-3.16. Comment: IETA appreciates the clarification within section 95921(b)(4)(D) that adjusts the reporting requirement to simply state whether a transaction agreement involves transfers for other products, and not to identify those other products.
IETA appreciates the additional clarity provided in Section 95920(d)(2)(G) within the proposed amendments as compared to January 2014's discussion draft. (IETA 2)

Response: Thank you for the support.

H-3.17. Comment: The 15-Day Changes present several significant revisions to the provisions of section 95921 regarding Conduct of Trade and includes two new definitions associated with it: section 95802(a)(138) "expected settlement date" and section 95802(a)(139) "expected termination date." The changes also include different rules for transactions through December 31, 2014 (including penalties associated with failure to meet timely transfers) and transactions beginning after January 1, 2015. It is difficult to reconcile the proposed revisions with all of the current practices that are part of the CITSS, and it does not appear that all of these changes have been fully worked through their practical application. To the extent that the proposed changes alter existing CITSS and common business practices, compliance entities and others registered in CITSS should have an opportunity to more thoroughly assess the implications and potential conflicts or shortcomings of the proposed changes prior to adoption by the Board. NCPA is also concerned with the implementation implications of imposing penalties for transactions that are not completed within 3 days, as proposed in section 95921(a)(3). (NCPA 3)

Response: ARB staff does not understand the commenter's portrayal of the requirements. The requirements proposed to be in effect through December 31, 2014 are the existing requirements with some minor additional text that currently exists in guidance documents. The requirement to complete the transfer request process within three days is already contained in the existing regulation. The text proposed to be effective through December 31, 2014 will conform to the existing CITSS transfer forms.

The transfer request procedures to take effect on January 1, 2015 will not be significantly different for most transfers from the current procedure. The requirements to enter quantity, price, and date of transfer agreement in CITSS are retained. Entities will be required to identify the type of transaction agreement, but these are already listed in CITSS currently as optional fields.

Entities with complex transaction agreements, such as those that specify price as some type of index plus a margin, will have to add more detail. However, the basic requirement to enter a price does not change. In cases where previously ARB has provided guidance that allows entities to enter a zero price, the CITSS will allow entities to identify the specific reason they qualify to enter a zero price. ARB currently deals with these cases by having the entities add explanations in CITSS or calling in the transaction agreements. Staff expects this new approach will provide the same information with less effort.

Staff conducted several workshops to develop the new changes, and stakeholders did not identify business practices that would be inhibited by the changes. Staff has called in a number of contracts under authority that has been part of the regulation since it came into effect. The specific changes proposed for section 95921(b) are based on the types of contract terms that staff has observed and discussed with many account representatives. The public process, which included two formal and one informal comment period, was more than adequate to give entities the opportunity to assess the changes.

Bid Guarantees

H-3.18. Comment: ARB has proposed the following language: "A bid guarantee submitted in any form other than cash must be payable within three business days of payment request." While this is an improvement from an earlier requirement of one day, this still seems to be an overly aggressive requirement. Certainly payment and reconciliation must be done promptly, but systems and people do fail and some provision needs to be made for the "normal course of business".
WSPA recommends the period be at least five working days to account for weekends, holidays, etc. (WSPA 5).

Response: After consulting with the Financial Services Administrator, and recognizing that undue delay in settling an auction is not desirable, ARB staff determined that 3 business days is sufficient to ensure an adequate processing of bid guarantees, and declines to modify this to 5 business days.

Intent to Participate

H-3.19. Comment: New Section 95912(f) specifies that an entity that "intends to participate" in an auction must inform the Auction Administrator at least 30 days prior to an auction of its intent to bid in an auction. Similarly, new Section 95913(e) provides that an entity must inform the reserve sale administrator at least 20 days prior to a reserve sale of its "intent to bid." CPEM requests that the ARB clarify that this indication of intent does not represent a binding commitment to participate in such auctions. For example, an entity may, more than 30 days prior to an auction, intend to participate, but prior to such auction find an over-the-counter transaction under which it can purchase the compliance instruments required at a fixed price, thereby avoiding auction risk, and rendering its auction participation unnecessary. CPEM recommends that Section

95912(f) be revised, as set forth below, with a corresponding change to Section 95913(e):

Auction Intent to Bid Notification Requirements. An entity that intends to participate in an auction must inform the Auction Administrator at least 30 days prior to an auction of its intent to bid in an auction, otherwise the entity may not participate in that auction. <u>Informing the Auction Administrator of an intent to bid does not commit the entity to participate in the auction.</u>

In the event ARB declines to make these changes, CPEM respectfully requests that Staff specify in the Final Statement of Reasons that an entity seeking to participate in an auction or reserve sale will not be in violation to the extent it evidences an "intent" to participate, but does not ultimately choose to do so. (CPM 2)

> **Response:** This section of the Regulation merely codifies the procedure for CITSS registered entities to participate in an upcoming auction; that is, an auction application in the auction platform must be completed by the participant no later than 30 days before an auction (this is the date on which auction applications in the auction platform close), and once that date has passed, an application cannot be completed and the entity cannot participate in the auction. There is no binding commitment on entities that complete an auction application should the entity subsequently decide not to participate, either by failing to submit a bid guarantee or by not bidding on the date of the auction. ARB staff therefore declines to accept the recommended change in the regulatory text.

H-4. Public Information Disclosure

Broad Information Requirements

H-4.1. Comment: Powerex appreciates that in its proposed amendment of CTR subsection 95830(c)(1)(I) CARB has narrowed the category of employees that would need to be disclosed in registrations. However, the currently proposed requirement, which would require disclosure of all employees "with knowledge of the entity's market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions)" remains very broad, burdensome, and impractical. This language would require Powerex to disclose all employees involved in trading, scheduling, and the settlement and accounting of power transactions — in sum, a significant percentage of Powerex's total staff. Such a result would dilute and undermine the purpose of subsection 95830(c)(1)(I), while unnecessarily burdening CITSS registered entities.

Powerex understands the need for disclosure of key employees, but urges ARB to take a more pragmatic approach to the disclosure requirement. Powerex supports WPTF's suggested amendment to subsection 95830(c)(1)(I), which would further narrow the category of employees that must be reported to those employees who "are authorized by the entity to initiate or approve compliance instrument transaction agreements or transfer requests." (POWEREX 2)

Response: ARB staff has worked with stakeholders in crafting the language in section 95830(c)(1)(I) to obtain information necessary for market monitoring without placing unwieldy administrative burdens on entities. During the 15-day comment period, staff revised the language in section 95830(c)(1)(I) to assuage stakeholder concerns about overly broad reporting requirements. In the final version of the amendment, section 95830(c)(1)(I) requires entities to report the names and contact information of individuals with access to compliance instrument holdings AND reported emissions, information that together can be used to manipulate the market. Staff believes that identifying individuals with access to both components of this highly sensitive information is imperative to ensuring a well-functioning market. This belief is supported by other agencies involved in market oversight including the U.S. Securities and Exchange Commission, the Federal Energy Regulatory Commission, and the California Independent System Operator. Staff will consider issuing guidance to further assist entities in complying with section 95830(c)(1)(I).

Staff does not agree with the proposed amendment to section 95830(c)(1)(I). Limiting the reporting of individuals who are registered as account representatives in the tracking system would not allow for proper market oversight.

H-4.2. Comment: But we do have some concerns regarding some of the provisions that are designed to prevent market manipulation. To touch on those briefly the 15-day language makes changes to disclosure requirements for employees. We believe those are improved over what was in the original amendment. But we'd like to see some refinement. The term "knowledge" must be limited to information that is not otherwise publicly available or easily discernable in order to avoid reporting that can be onerous. As SCE noted, some of these requirements can be onerous, but not just for large entities, for small entities as well. And we support the recommendation to work with staff and stakeholders to review the provisions and develop solutions that will address these concerns. We also question whether these disclosure requirements are necessary at all if proposed revisions are adopted that impose an absolute prohibition on employees registering as voluntarily associated entities. We thank you very much and support the revisions. (NCPA 4)

Response: Staff has worked with stakeholders in crafting the language in section 95830(c)(1)(I) in order to obtain information necessary for market monitoring without placing unwieldy administrative burdens on entities. During the 15 day comment period, staff revised the language in section 95830(c)(1)(I) to assuage stakeholder concerns about overly broad reporting requirements. In the final version of the amendment, section 95830(c)(1)(I) requires entities to report the names and contact information of individuals with access to compliance instrument holdings AND reported emissions, information that together can be used to manipulate the market. Staff believes that identifying individuals with access to both components of this highly sensitive information is imperative to ensuring a well-functioning market. Staff will consider issuing guidance to further assist entities in complying with section 95830(c)(1)(I).

H-4.3. Comment: PacifiCorp proposes that the California Air Resources Board ("ARB") modify section §95830(c)(I) to remove the requirement to submit names and contact information for all persons employed by the entity with knowledge of the entity's market position. This requirement is inefficient and administratively burdensome, as well as poorly designed to achieve a meaningful objective. In particular, this requirement will be unduly burdensome for large entities such as PacifiCorp, with numerous employees who have or could have knowledge regarding current or expected holdings of compliance instruments and/or expected covered emissions but who have no knowledge of or decision-making role in the auction process. Furthermore, the large volume of information in the form of names of utility back office and accounting personnel that ARB will receive from this requirement is unlikely to provide an effective mechanism for ARB to prevent conflicts of interests from occurring between auction participants, or ((Ven to provide data from which useful information can be obtained. A comprehensive employee list, which will be relatively extensive and dynamic, is likely to be unwieldy and impractical for purposes of preventing or identifying conflicts of interest. Further diminishing the usefulness of such information, employees of one utility often go to work for another utility. This is normal but unlikely to result in the sharing of market participant auction strategies and information; however, the existence of a "list" may give rise to questions and inhibit workers from pursuing their most optimal employment opportunity. If the intent of this requirement is to prevent conflicts of interest among auction participants, ARB should propose language that more directly prohibits conflicts of interest (in all its forms) and then develop auditing tools to enforce this direct prohibition. (PACIFICORP 2)

Response: ARB staff has worked with stakeholders in crafting the language in section 95830(c)(1)(I) in order to obtain information necessary for market monitoring without placing unwieldy administrative burdens on entities. During the 15 day comment period, staff revised the language in section 95830(c)(1)(I) to assuage stakeholder concerns about overly broad reporting requirements. In the final version of the amendment, section 95830(c)(1)(I) requires entities to report the names and contact information of individuals with access to compliance instrument holdings AND reported emissions, information that together can be used to manipulate the market. Staff believes that identifying individuals with access to both components of this highly sensitive information is imperative to ensuring a well-functioning market. This belief is supported by other agencies involved in market oversight including the U.S. Securities and Exchange Commission, the Federal Energy Regulatory Commission, and the California Independent System Operator. Staff will consider issuing guidance to further assist entities in complying with section 95830(c)(1)(I).

H-4.4. Comment: CARB has further revised language in Section 95830 (Registration with CARB) requiring CITSS entities to disclose names and contact information of certain employees. The language now requires disclosure only employees “with knowledge of the entity’s market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions).”

While we appreciate staff’s continuing effort to address stakeholder concerns regarding the breadth of this text, the new revision is several steps backward. As we have previously commented, we do not consider it appropriate for CARB to require disclosure of employees who have knowledge of entity’s holdings of compliance instruments simply because of their administrative and legal duties. Thus we strongly consider that the disclosure obligation should apply only to employees who both have knowledge of the entity’s compliance instrument market position and the ability to influence this market position through decision-making regarding compliance instrument procurement or transfer.

WPTF also considers the addition of new language that would extend the disclosure requirement to employees with knowledge of “current and/or expected covered emissions” to be inappropriate. First, it would cover all employees involved in the internal greenhouse gas inventory and reporting or mitigation efforts, regardless of whether those employees also manage holdings of compliance instruments. Second, for electricity importers, this provision would require disclosure of all employees involved in trading, scheduling, settlement or accounting of power transactions, as these individuals would have some knowledge of the emissions exposure created by those transactions.

We therefore urge that staff to modify section 95830(c)(1)(i) to read:
Names and contact information for all persons employed by the entity with knowledge of the entity’s market position (current and/or expected holdings of compliance instruments) current and/or expected covered emissions) that are authorized by the entity to initiate or approve compliance instrument transaction agreements or transfer requests. (WPTF 3)

> **Response:** ARB staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will address the issue in guidance. Staff does not agree that the proposed modification to section 95830(c)(1)(I) is appropriate as it eliminates the ability of ARB to identify entities that may be coordinating through shared employees with access to compliance account holdings and reported emissions, information that together could be used to manipulate the market.

H-4.5. Comment: WSPA is concerned with a number of complicated reporting rules that could jeopardize the ability of regulated entities to participate in the auction. We understand the agency’s need to identify participants who may have the intent of disrupting the allowance market (i.e., “bad actors”). That intent notwithstanding, rules must be designed so parties with legitimate interests in a market system are able to avoid inadvertent missteps. The agency already has substantial ability to initiate enforcement actions against participants up to, and including, cancelling an auction. Accordingly, the addition of even more restrictive rules will not enhance ARB's ability to deter unwanted behavior.

We appreciate and agree directionally with ARB's proposed revision to Section 95830(c)(1)(I). This change goes a long way to preserve ARB's intent and also recognize the needs of market participants.

ARB should further clarify this section as follows: "…all persons employed by the entity with full knowledge of the entities market position" (WSPA 5)

> **Response:** Thank you for the comment. ARB staff does not agree that the proposed modification to section 95830(c)(1)(I) is appropriate as "full knowledge" is overly subjective and may eliminate the reporting of individuals with access to compliance account holdings and reported emissions that can be used to manipulate the market.

H-4.6. Comment: Brookfield appreciates the most recent modifications to this section that limit the requirement for CITTS entities to disclose names and contact information of employees with access to information on compliance instruments to those employees "with knowledge of the entity's market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions)." However, this requirement is still overly broad and would create an onerous administrative burden that would require the disclosure of a large number of employee information that may have some knowledge but are not the decision makers. As roles and responsibilities change this information would have to be continuously updated. This creates a large administrative challenge for covered entities. Brookfield recommends CARB retain the existing practices in regards to CITTS registration as it is unclear what benefit collecting large quantities of employee information will provide to CARB. If CARB insists on collecting additional information, Brookfield requests this requirement be limited to employees with knowledge of the entity's market position as well as decision making authority over current and expected holdings and/or expected covered emissions. Rather than proposing our own modifications to the language we support WPTF's proposed 15-day modifications to this section. Brookfield also is concerned that such disclosure of the personal information of individual employees who are peripherally involved in an entity's market functions potentially raises privacy concerns. By limiting disclosure to employees with knowledge of an entity's market position, these concerns would be mitigated. (BEM 2)

> **Response:** ARB staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will address the issue in guidance. However, staff does not agree that the proposed modification to section 95830(c)(1)(I) is appropriate as it would eliminate the ability of ARB to identify entities that may be coordinating through shared employees with access to both compliance instrument holdings and reported emissions, information that could be used to manipulate the market. Staff does not agree that requesting the name and

contact information of individuals with access to both compliance holdings and reported emissions raises privacy concerns. Section 95830(c)(1)(I) does not require the disclosure of “employees who are peripherally involved in an entity’s market functions” rather it requires the disclosure of a narrow scope of individuals with knowledge of both compliance instrument holdings and reported emissions. The intent is not to require disclosure of individuals casually aware or associated with issues related to compliance instruments or reported emissions, but to identify employees that are responsible for compliance strategy by knowing information on both an entity’s holdings and emissions.

H-4.7. Comment: SCE appreciates the ARB’s efforts to more specifically address which employee functions and responsibilities would necessitate covered entities to close contact information pursuant to Section 95830(c)(1)(I) of the 15-Day Modifications. However, SCE believes that the proposed language still captures far more employees than the ARB intends to capture, or needs to know about, in order to perform its market monitoring duties. As currently proposed, the ARB would require registering entities to report the names and contact information for employees “with knowledge of the entity’s market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions)”The requirements imposed by this language would result in reporting contact information not only for personnel who execute or oversee transactions involving compliance instruments, but also employees in risk control, settlements, accounting, compliance, legal, and various other job functions who have only tangential involvement in the market for cap-and-trade compliance instruments and no power to influence the entity’s market transactions. As the roles and responsibilities of these employees may change frequently, this requirement would present an onerous administrative challenge for participating entities to maintain and update on a quarterly schedule. SCE proposes the following language changes (in **bold**) to Section 95830(c)(1)(**I**) of the 15-Day Modifications:

“Names and contact information for all persons employed by the entity with **the authority to initiate or approve transactions of compliance instruments** ~~knowledge of the entity’s market position (current and/or expected covered emissions).~~” SCE’s proposed language would relieve some of the administrative burden on participating entities while still allowing the ARB to collect contact information on employees with direct transactional or decision-making involvement in the market for compliance instruments. (SCE 4)

Response: ARB staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will address the issue in guidance. However, staff does not agree that the proposed modification to section 95830(c)(1)(I) is appropriate as it restricts the ability of ARB to identify entities that may be coordinating through shared employees not authorized to transfer compliance instruments, but with access to both compliance instrument holdings and reported emissions, information that could be used to manipulate the market. Information on individuals with the authority to initiate or approve transfers of compliance instruments is collected through the tracking system and this new section is intended to augment, not duplicate, that information for market oversight.

H-4.8. Comment: It is our understanding that staff desires to capture only those individuals who are familiar with the entity's market position. We suggest the following language which would provide that information while minimizing the reporting burden on regulated entities:(I) Names and contact information for all persons employed by the entity in a capacity giving them access to information on compliance instrument transactions or holdings, or involving them in decisions on compliance instrument transactions or holdings who have clearance from the entity to approve, or initiate, or review transaction agreements, transfer requests, or account balances involving compliance instruments in the Cap-and-Trade Program or any External GHG ETS linked pursuant to subarticle 12. (BP 2)

Response: Thank you for the comment. ARB staff appreciates your interpretation of the intent of section 95830(c)(1)(I) and will consider issuing guidance to further assist entities comply with this requirement. The intent is not to require disclosure of individuals casually aware or associated with issues related to compliance instruments or reported emissions but to identify employees that are responsible for compliance strategy by knowing information on both an entity's holdings and emissions. Staff does not agree with the proposed modification to the text as it relies on entity "clearance" to disclose individuals which may vary by entity. This can result in uneven disclosure by entities and will not enable full monitoring of the market.

H-4.9. Comment: The proposed requirement of §95830(c)(1)(I) would involve a significant number of employees at a large entity such as LADWP. Implementation of the requirement would be time consuming, very difficult to keep the information updated even on a quarterly basis, and unnecessary. Thus, LADWP recommends deletion of §95830(c)(1)(I).

As mentioned above, LADWP believes there is no need for inclusion of §95830(c)(1)(I) as individuals who are employed by an entity covered under the MRR or Cap-and-Trade Program would be prohibited from registering as a VAE and participating in the cap-and-trade market. Thus, the following sentence in §95830(f)(1) should be deleted: "Updates of information provided pursuant to section 95830(c)(1)(I) may be updated each calendar quarter instead of within 30 calendar days of the change." (LADWP 3)

Response: ARB staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will consider issuing guidance to further assist entities comply with this requirement. The intent is not to require disclosure of individuals casually aware or associated with issues related to compliance instruments or reported emissions but to identify employees that are responsible for compliance strategy by knowing information on both an entity's compliance instrument holdings and reported emissions. Moreover, section 95830(c)(1)(I) addresses concerns beyond the scope of section 95814(a)(7) and is therefore necessary. Section 95830(c)(1)(I) is intended to assist in market monitoring which is not covered under section 95814(a)(7) and therefore both sections are necessary for effective monitoring of the market.

H-4.10. Comment: ARB has further revised language requiring CITSS entities to disclose names and contact information of employees with knowledge of an entity's "market position" (current and/or expected holdings of compliance instruments and current and/or expected covered emissions). For any organization that produces an energy related commodity, their carbon allowance obligation is directly related to the output of their facilities, and marketing activities. The expansion of the disclosure requirements, as currently written, would encompass the majority of all staff associated with production, generation and marketing. All staff have indirect knowledge of an entity's expected covered emissions attributed to production, and could derive the requisite holding of compliance instruments necessary to hedge daily production and trading. TransAlta feels this language is too broad and would make it very difficult to identify all those employees who need to be disclosed.

TransAlta requests that ARB changes this requirement by specifically narrowing the disclosure requirement to those employees who have knowledge of an entity's current compliance market position and have decision-making capacity regarding holdings, transactions, transfers and retirement, or access to the entity's CITTS account. This modification would remove the need to disclose back office staff that do not have transaction capabilities, and specifically identify those select front office employees who must be disclosed.

We therefore ask that staff alters section 95830(c)(1)(i) to read:
Names and contact information for all persons employed by the entity with knowledge of the entity's market position (current and/or expected holdings of compliance instruments) ~~current and/or expected covered emissions)~~ <u>that are authorized by the entity to initiate or approve compliance instrument transaction agreements or transfer requests</u>. (TA)

Response: ARB staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will consider issuing guidance to further assist entities comply with this requirement. However, if it is the case that "all staff" have knowledge of an entity's reported emissions and compliance instrument holdings, ARB believes disclosing the names and contact information of "all staff" to ensure the integrity of the market is appropriate. Staff does not agree that the proposed modification to the text is appropriate as it eliminates the disclosure of individuals with access to information that can be used to manipulate the market and it duplicates information already collected in the tracking system.

H-4.11. Comment: At Regulations section 95830(c)(I)(I), ARB has further amended the requirement that entities provide information on employees or contractors that are involved with an entity's Greenhouse Gas Cap-and-Trade Program ("Program") compliance. While SGEN understands that ARB needs a record of the individuals responsible for an entity's conduct, as well as those that have delegated authority to enter into transactions on behalf of the entity, the language as amended continues to be overly broad and could be interpreted to require entities to provide information on employees with minor, non-substantive administrative roles in the Program.

The language of section 95830(c)(l)(I), which refers to "... all persons employed by the entity with knowledge of the entity's market position (current and/or expected holding of compliance instruments and current and/or expected covered emissions)...." could be read to include employees that perform solely administrative functions focused, for example, on processing settlement data. These duties are performed by employees not involved in any substantive decisions related to the Program, although they would be exposed to "knowledge" of an entity's "holding of compliance instruments." Indeed, sometimes these types of jobs are performed by contract, temporary, or rotational employees. Presumably, ARB is really concerned with the identity of those individuals developing an entity's compliance instrument procurement strategy, those communicating with other market participants to buy or sell compliance instruments, those establishing an entity's auction bidding strategy, those participating in the quarterly auctions, or those involved in other substantive decision-making for a company registered in the Program.
Thus, SGEN suggests that section 95830(c)(1)(I) be revised to state as follows, in order to focus on employees with substantive decision-making authority for an entity's Program participation:

Names and contact information for all persons employed by the entity involved in decision-making regarding compliance instrument procurement, the transfer of compliance instruments, or the entity's holdings of compliance instruments in the Cap-and-Trade Program or any External GHG ETS linked pursuant to subarticle 12. (SEMPRA 3)

> **Response:** Staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will consider issuing guidance to further assist entities comply with this requirement. The intent is not to require disclosure of individuals casually aware or associated with issues related to compliance instruments or reported emissions but to identify employees that are responsible for compliance strategy by knowing information on both an entity’s holdings and emissions. Disclosing individuals, especially contract, temporary, or rotational employees, with knowledge of both an entity’s compliance instrument holdings and reported emissions is necessary to ensure robust market monitoring and to prevent market manipulation. Staff does not agree that the text proposed by the commenter is appropriate as it eliminates the disclosure of individuals that have knowledge of compliance strategy, but that are not involved in the decision-making regarding procurement of compliance instruments.

H-4.12. Comment: M-S-R supports the language in the 15-Day Changes that revise the scope of responsibilities that an employee must have in order to warrant reporting and disclosures to CARB, but urges the Board to direct that further refinements be added to ensure that employees with access to publicly available information are not included in the definition. Any additional reporting and disclosure requirements must be tempered to ensure that they do impose unduly restrictive and burdensome requirements on registered entities, or mandates that may simply be unenforceable. The proposed language in the 15-Day Changes that requires the reporting of "names and contact information for all persons employed by the entity with knowledge of an entity's market position (current and /or expected holdings of compliance instruments and current and/or expected covered emissions)," narrows the scope of the requested information previously sought, but remains a concern in that information regarding current or expected covered emissions is generally publicly available. M-S-R asks that the Board direct that this definition be further refined to clarify that "knowledge" regarding covered emissions must be coupled with knowledge regarding expected holdings, and that such knowledge is gained during the course of the employee's employment responsibilities, rather than simply having access to publicly available information. Accordingly, section 95830(c)(1)(I) should be revised to read: "names and contact information for all persons employed by the entity with knowledge of both an entity's market position (which includes both current and/or expected holdings of compliance instruments and current and/or expected covered emissions) and tracking system account information that is not publicly available." (MSR 2)

Response: Staff appreciates the concern that section 95830(c)(1)(I) will be overly burdensome on entities and will consider issuing guidance to further assist entities comply with this requirement. The intent is not to require the disclosure of individuals with access solely to publically available data. However, knowledge of compliance strategy and account holdings in concert with knowledge of public data pertaining to reported emissions would necessitate disclosure under section 95830(c)(1)(I). Staff does not agree that the text modification proposed by the commenter is appropriate as it would eliminate the disclosure of individuals that have knowledge of compliance strategy, but that are not involved in the decision-making regarding procurement of compliance instruments.

H-4.13. Comment: CARB has expressed a desire for greater information regarding individuals with knowledge of market strategies. The 45-day Proposed Amendments added Section 95830(c)(1)(I) to define the scope of employment the rule was targeting, and require additional reporting and disclosure rules. Like many stakeholders, NCPA expressed concerns regarding the breadth of the definition set forth in the Proposed Amendments. NCPA appreciates the recognition of these concerns that are reflected in the revisions in the 15-Day Changes that attempt to limit the scope of the employee's responsibilities relevant to the Program and CARB's reporting requirements. However, NCPA urges the Board to direct that further refinements and clarifications be added to the definition. The intent of this section, as described by staff, is to ensure that CARB has a list of employees with control over decisions regarding the disposition and acquisition of compliance instruments. In response to concerns raised by stakeholders, the Board directed staff to refine the definition. As set forth in the 15-Day Changes, the section would require entities to report "names and contact information for all persons employed by the entity with knowledge of an entity's market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions)."

This language is preferable to the language set forth in the 45-day Proposed Amendments because it strikes the vague reference to anybody "in a capacity giving them access to information on compliance instrument transactions or holdings . . . ," and narrows the scope of the request. NCPA remains concerned, however, that defining all of the individuals "with knowledge of an entity's market position" could be problematic without a more detailed definition of "market position," especially as it pertains to "current and/or expected covered emissions." Information regarding current or expected covered emissions is commonly reported publicly by compliance entities and various agencies. Furthermore, it is very easily ascertained from publicly available knowledge. The definition should be carefully crafted to ensure that the employees with "knowledge" is limited to those individuals that have access to tracking system account information, compliance instrument procurement, and emissions obligations. NCPA urges the Board to direct that section 95830(c)(1)(I) be revised to read: "names and contact information for all persons employed by the entity with knowledge of both an entity's market position (which includes both current and/or expected holdings of compliance instruments and current and/or expected covered emissions) and tracking system account information that is not publicly available."

These clarifications would ensure that the definition is not so vague as to cover employees that have knowledge of market information simply by virtue of the fact that the information at issue is publicly available. Furthermore, NCPA believes that CARB should monitor implementation of this provision to ensure that it is not unduly burdensome for registered entities.

Finally, given other proposed revisions to the Regulation, this section may no longer be needed to address CARB's concerns. In light of the fact that the 15-Day Changes includes a proposed new section (95814(a)(7)) that disallows all employees of covered entities from registering as voluntarily associated entities, NCPA believes that the additional reporting relevant to this specific class of employees is unnecessary and should be removed entirely. (NCPA 3)

> **Response:** Staff appreciates the concerns raised by the commenter. The intent is not to require disclosure of individuals casually aware or associated with issues related to compliance instruments or reported emissions but to identify employees that are responsible for compliance strategy by knowing information on both an entity's holdings and emissions. Staff does not agree that the text requires additional amendment and will work to address concerns about the scope of individuals required to disclose name and contact information in guidance.
>
> Section 95830(c)(1)(I) addresses concerns beyond the scope of new section 95814(a)(7) and is therefore necessary. Section 95830(c)(1)(I) is intended to identify employees with access to an entity's market position for market

monitoring to identify relationships between entities and prevent market manipulation. Section 95814(a)(7) prohibits employees from registering as Voluntarily Associated Entities but does not require entities to report employees that have access to information about the entity's market position. Therefore both sections are necessary.

H-4.14. Comment: As we indicated in previous comments, WSPA recognizes the ARB must be notified when details of company registrations change. However, as the registration requirements grow in complexity, it is incumbent upon ARB to grant more time for changes to be fully implemented throughout the companies, up to and including registrations on file with the ARB. Changes in employees, consultants and advisors, and most of all, corporate associations, may not be communicated quickly nor widely within regulated entities. While we appreciate the proposed extension from 10 days to 30 days, this extension still does not provide enough time for information transfer within large entities. The extent of compliance risk to regulated entities for potential violations of this administrative requirement alone justifies additional time.

ARB should revise this requirement to a 60-day notification. However, the language still lacks of clarity which could cause inadvertent non-compliance.
ARB should further clarify this section as follows: "…all persons employed by the entity with <u>full</u> knowledge of the entities market position"

We recognize and appreciate that ARB changed the required frequency to update registration information provided pursuant to section 95830(f)(1) from within 30 days to each calendar quarter of the change. WSPA also supports the proposed clarification to section 95830(c)(1)(H) allowing updated information to be submitted within 30 calendar days provided they are related to entities registered in the C/T program. (WSPA 5)

Response: Staff appreciates the concern that updates to information related to consultants and advisors, employees with knowledge of compliance strategy, and corporate associations may be burdensome. However, staff does not agree that the time for reporting changes in this information should be lengthened from 30 to 60 days. In the proposed amendments, the time line for reporting was lengthened from 10 to 30 days in recognition of the administrative work associated with identifying and reporting changes to information. However, the information related to consultants and advisors, employees with knowledge of compliance strategy, and corporate associations is required in a timely manner to facilitate market oversight. Increasing the allowable time for reporting changes to information will decrease the ability of ARB to ensure the market is well-functioning and therefore is not appropriate.

Staff does not agree with the proposed modification to section 95830(c)(1)(I) as the term 'full knowledge' is overly subjective and would require evaluation on a case by case basic which is unduly burdensome.

H-4.15. Comment: WSPA supports ARB's proposed change in section 95833(e)(3) to require notification of changes to information disclosed on corporate, direct and indirect corporate associations on a quarterly basis in lieu of the prior 30-day time limit. §95833(f)(7). The proposed language appears to clarify that a corporate association exists only if 1) the primary account representative or alternate who is an employee of one registered entity manages compliance instruments both for their employer and another registered entity or 2) the PAR/AAR has access to "market position" information for another registered entity ***and*** the authority to act on such information on behalf of that entity. We agree that these circumstances warrant application of the requirements for corporate associations.

> **Recommendation:** To avoid potential unintended corporate associations between unrelated registered entities who happen to be represented by the same third party PAR/AAR, ARB should further amend the second sentence of this section as follows: "If any primary account representative or alternate account representative of a registered entity*, who is also an employee of that entity,* has access to the market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions) for multiple registered entities …"(WSPA 5)
>
> **Response:** Thank you for the support of the modification proposed in sections 95833(e)(3) and 95833(f)(7). Staff does not agree with the commenter's proposed modification of section 95833(f)(7). The text currently contains language requiring that the primary or alternative account representative with primary responsibility over multiple accounts must be employed by the registered entity.

H-4.16. Comment: The proposed language at section 95833(f)(7), if read literally, could severely limit and will unreasonably complicate the management and advisory services that companies have traditionally provided to participants in existing markets. Proposed section 95833(f)(7) states in part:

If some or all of the primary and alternate account representatives who are employees of a registered entity have primary responsibility for developing and executing procurement, transfer, and surrender of compliance instruments of another registered entity or other registered entities within the tracking system, the entities will be considered to have a direct corporate association and the requirements of section 95833(f) apply.

In its Initial Statement of Reasons issued on September 4, 2013, staff explained that section 95833(f)(7) was added to "require covered entities who share staff for management of their tracking system accounts to be treated like direct corporate associations with a sharing of the purchase or holding limits," since this may lead to "... the potential to coordinate on market related decisions. . ."

While the Cap-and-Trade Program and carbon market are fairly new, the type of energy management and broker services that this proposed language appears to constrain are services that are not uncommon or prohibited in commodity markets generally. Indeed, companies routinely offer and provide services to other market participants which often include management of market positions, providing recommendations on market position valuation, analysis, and strategy, as well as establishing and maintaining various accounts on behalf of a client so the agent can procure and manage Congestion Revenue Rights, bid-in and schedule a client's generation assets in the day-ahead and real-time markets, and buy and sell gas or power. Companies that provide these services implement robust policies, procedures and compliance programs to ensure compliance with, and ensure employees are well educated on, the same conduct that appears to be at the crux of ARB's concern: compliance with antitrust laws, avoidance of conduct that unreasonably restrains competition, conflict of interest, and the obligation to keep any information obtained as part of an advisor-client relationship confidential. The duties performed by one market participant on behalf of another market participant under these arrangements are allowable by market monitors, who are authorized to observe participants' behavior in the market, to ensure that an open and competitive market is maintained and to prevent no one participant from being able to take unfair advantage of the market rules or procedures, to unduly concentrate market power, or to inhibit competition.

If approved, however, the proposed language at section 95833(f)(7) noted above would impose on both entities the requirement to treat each other as if they had a 'direct corporate association' with all of the obligations under the Regulations that this relationship entails, despite the fact that the two entities have only an agent-client relationship and are not, in fact, legally related in any generally accepted corporate entity sense. This is entirely inappropriate and unworkable, as is the requirement to treat two entirely unrelated legal entities as related for the purposes of sharing purchase and holding limits. Section 95833(f)(7) should be removed from the proposed amendments. (SEMPRA 3)

> **Response:** ARB staff does not agree that section 95833(f)(7) should be eliminated as it addresses issues that previously had not been addressed in the Regulation, related to individuals that have primary responsibility for the compliance strategies of more than one entity. Staff believes that section 95833(f)(7) is necessary for proper market oversight, but does not intend for the proposed amendment to impede market functioning and established market services. Staff will consider providing guidance regarding the scope and scale of section 95833(f)(7) to assist entities comply with the requirements for section 95833(f)(7).

Auction Bid Advisor

H-4.17. Comment: Section 95914(c)(3) includes a series of requirements to help ensure that a Cap-and-Trade Consultant or Advisor (“Consultant/Advisor”) does not improperly share auction information. Section 95914(c)(3)(A) specifies that, if an entity participating in an auction has retained the services of a Consultant/Advisor regarding auction bidding strategy, then “the entity must ensure against the Consultant or Advisor transferring information to other participants or coordinating the bidding strategy among other participants.” Section 95914(c)(3)(B) specifies that the entity will inform the Consultant/Advisor of the prohibition against sharing information with other participants, and ensure that the Consultant/Advisor has read and acknowledged the prohibition under penalty of perjury. Section 95914(c)(3)(C) specifies that the Consultant/ Advisor themselves must provide information to the Executive Officer, including “Assurance under penalty of perjury that the advisor is not transferring to or otherwise sharing information with other auction participants.”

CPEM applauds the ARB’s proposal as set forth in Section 95914(c)(3)(C) to place the onus on the Consultant/Advisor to assure that they are not inappropriately sharing information and to be liable for their actions. As part of this change, however, the ARB should also remove Section A, which requires that the participating entity itself must “ensure” against improper action by the Consultant/Advisor. The participating entity itself does not have any ability to “ensure” the actions of the Consultant/Advisor. The participating entity can ensure that the Consultant/Advisor executes a document acknowledging the prohibition, as required by Section 95914(c)(3)(B), and can provide appropriate training, etc. – but the participating entity does not have the ability to “ensure” the actions of a non-employee, and should not be held liable if, despite the participating entity’s diligent efforts, the Consultant/Advisor acts with malfeasance and shares information.

Given the addition of Section 95914(c)(3)(C), which strengthens the ARB’s ability to proceed directly against a Consultant/Advisor in the event such Consultant/Advisor inappropriately shares information, Section 95914(c)(3)(A) is simply not necessary. To the extent the ARB declines to delete this section, CPEM requests that Staff acknowledge in the Final Statement of Reasons that a participating entity will not be liable under Section 95914(c)(3)(A) for acts of a Consultant/Advisor beyond the participating entity’s ability to control. (CPM 2)

> **Response:** Staff respectfully disagrees that section 95914(c)(3)(A) is not necessary or that section 95914(c)(3)(C) places the responsibility for not disclosing confidential information listed in section 95914(c)(1) solely on Cap-and-Trade Consultants and Advisors. The responsibility lies with both the entity and the Consultant/Advisor. Entities can take a variety of steps to minimize the possibility of a release of confidential information by a Consultant/Advisor. For example, the entity can control data security requirements (paper and electronic) it requires of the Consultant/Advisor or the Consultant’s employer. The exact nature of the business arrangement between the entity and the Consultant/Advisor and what requirements entities may put in place to minimize the release of confidential data are business decisions that these parties must decide for themselves. Staff strongly recommends that entities carefully consider those business arrangements in light of the confidential information that

Consultant/Advisors are likely to know. Staff declines to delete section 95914(c)(3)(A).

H-4.18. Comment: The 15-Day Changes clarify an earlier proposal to revise the definition of auction advisor that would have greatly expanded the applicability of the provision to include individuals and companies that provide services to a registered entity totally unrelated to bidding strategies. M-S-R supports the currently proposed definition in Section 95914(c)(3) that limits the scope of advise to Cap-and-Trade Consultants and Advisors that provide advice on "auction bidding strategy," and that likewise limits the required disclosures in section 95914(c)(3)(C) to Cap-and- Trade Consultants and Advisors providing bidding advice. The Regulation properly includes this clarifying term in section 95914(c)(3) regarding the applicability of the section 95923 definition for Cap-and-Trade Consultants and Advisors. (MSR 2)

Response: Staff appreciates the support for the 15-days changes. In the interest of clarity, staff notes that section 95914(c) as a whole prohibits the sharing of information regarding bidding strategy, intent, or no intent, to participate in an auction, bid price, and bid guarantee information. This prohibition applies to registered entities, corporate associations, and Cap-and-Trade Consultants and Advisors (see Section 95923 for references to the services a Consultant/Advisor could perform to meet the regulatory definition). Section 95914(c)(3) requires those Consultants/Advisors providing advice on bidding strategy (which encompasses information essential to bid strategy – such as bid price, bid guarantees, etc.) to disclose the information in subparagraph (C) to ARB. Thus, the reference to "auction bidding strategy" is intended to make entities and Consultant/Advisors engaged in developing bidding strategy for the entity cognizant of the prohibitions on information sharing. Both parties are expected to exercise due diligence and care to avoid sharing highly sensitive auction information with other auction participants.

H-4.19. Comment: Section 95914(c)(3) changes the definition of "auction advisor" to incorporate the broader "Cap-and-Trade Consultant or Advisor, as defined in section 95923." As proposed, this section now reads "if an entity participation in an auction has retained the services of a Cap- and-Trade Consultant or Advisor, as defined in section 95923, regarding auction bidding strategy, then . . ." As set forth in the Discussion Draft, the definition was unduly broad, in that it would have invoked the myriad other consultants and advisors defined in section 95923, rather than just those individuals/companies that are providing advice specific to auction bidding strategies. NCPA fully supports further refining the Cap-and-Trade Consultant and Advisor definition under this section to specifically apply only to those individuals/companies providing bidding advice, and application of the provisions of section 95914(c)(3)(C) to those individuals/companies that are providing bidding advise. (NCPA 3)

Response: Staff appreciates the support for the 15-day changes to this section of the Regulation.

Confidentiality Protections

H-4.20. Comment: NCPA supports the language in new section 95914(c)(2)(C) of the Proposed Amendments recognizing that there are instances under which auction bidding information may be disclosed. This new section correctly authorizes the release of information that would have otherwise been prohibited under 95914(c)(1), and is properly amended to allow for limited exceptions to the restrictions on disclosure of auction-related information consistent with the CARB's existing Regulatory Guidance Document. (NCPA 3)

> **Response:** Staff appreciates the support for the 15-day changes to this section of the Regulation.

H-4.21. Comment: PG&E strongly supports the ARB's regulatory principle of protecting market-sensitive AB 32- related information, including bidding information, from disclosure that could lead to market manipulation or collusion among auction participants. PG&E appreciates that Section 95914(c) of the 15-day proposed regulations attempts to strike a careful balance between maintaining confidentiality and providing for very limited disclosure by order or authorization of the CPUC or other regulatory agency with direct jurisdiction over privately owned California utilities where the CPUC or other regulatory agency determines such disclosure is necessary under its procedural or substantive rules, orders or decisions. With some minor clarifications as follows, PG&E supports the ARB's balanced approach.

First, PG&E assumes that the reference to "auction participation" in Section 95914(c)(1)(A) references future auctions, not historical auction results, where the auction participants and results have previously been publicly disclosed. To confirm this interpretation, PG&E recommends the following clarification to Section 95914(c)(1)(A): (A) Intent to participate, or not participate, at a prospective auction, prospective auction approval status, maintenance of continued auction approval; (PGE 4)

> **Response:** As ARB releases the names of Qualified Bidders after an auction, per section 95912(k)(5)(A), section 95914(c)(1)(A) could only apply to a prospective auction. Staff believes that no further clarification is needed and thus declines to make the suggested change to the regulatory text.

H-4.22. Comment: PG&E does not oppose reverting to language set forth in the draft 15-day amendments released on January 31, 2014, which required IOUs to provide such information upon the request of the Executive Officer. However, PG&E does oppose the requirement to provide ARB with a justification of permitted disclosures to the CPUC within 10 business days of each disclosure. For administrative efficiency and to reduce reporting burdens on the ARB, CPUC, and utilities, PG&E recommends that the Executive Officer reporting requirements for disclosures under Section 95914(c)(1)(D) be periodic and categorical.

Under PG&E's proposal, regulated entities would be required to maintain records of all such disclosures and such records would be available for inspection by the Executive Officer and ARB staff, similar to the language in the draft 15-day amendments released on January 31, 2014. To the extent that the CPUC requires or authorizes utilities to make periodic or recurring disclosures to entities other than the CPUC, such as to non-market participants, record-keeping of the actual disclosures should be sufficient and avoid confusion and unnecessary paperwork.

> **Recommendation:** The following amendment to the draft language would accomplish this burden reduction:
>
> (D) When the release is by an entity regulated by an agency that has regulatory jurisdiction over privately owned utilities in the State of California ~~electric distribution utility~~ of information regarding compliance instrument cost and acquisition strategy and other disclosures specifically required or authorized by the regulatory agency ~~California Public Utilities Commission.~~ pursuant to any of its applicable rules, orders, or decisions. In the event of a disclosure pursuant to this section to entities other than the agency with regulatory jurisdiction, the regulated entity must provide to the Executive Officer the category of information and statutory or regulatory reference or the general order, decision or ruling that requires or authorizes such disclosure within 10 business days . ~~related to bidding strategy~~. The entity shall maintain records of all such disclosures and shall make the records available for inspection by the ARB upon request. (PGE 4)
>
> **Response:** The requirement in section 95914(c)(2)(D) is related strictly to disclosures of information specified in section 95912(c)(1), i.e., auction participation, auction approval status, bidding strategy, bid price or bid quantity information or the bid guarantee provided to the Financial Services Administrator. The commenter implies that it expects to make such disclosures frequently and will therefore be sending a steady stream of notices to ARB providing the regulatory or statutory provision, general order, decision or ruling that required the disclosure. ARB staff respectfully disagrees as there are only eight auctions and/or reserve sales per year where the commenter and similarly situated entities would need to disclose their participation, bidding strategy or bid guarantee under regulatory order or regulatory rules and decisions. ARB staff does not believe that the commenter's (and other regulated entities) normal procurement activities need trigger a disclosure of auction participation or bidding strategy by CPUC regulation, order or decision. Allowances are available from non-auction sources, including the secondary market and via allocation from ARB. Staff is willing work with the commenter and other regulated entities subject to this provision of the Regulation and develop guidance to assist these entities comply with the disclosure requirements in an efficient manner, while still letting ARB know that a disclosure was made. Staff also believes the record-keeping requirements proposed by the commenter would actually be more burdensome than the amended regulatory text. In addition, staff is concerned about the possibility that

such records might be incomplete at the time they are inspected by ARB staff. Staff therefore declines to make the suggested change in the regulatory text.

H-4.23. Comment: Section 95914(c)(2)(D) on non-disclosure of bidding information provides helpful guidance on permissible release of information required by an agency with regulatory jurisdiction over privately owned utilities. SDG&E and SoCalGas have proposed additional clarifying language below. The proposed language clarifies that Section 95914(c)(2)(D) addresses the information identified in Section 95914(c)(1)(A)-(D) for internal consistency. The proposed language also provides for regulatory efficiency by not requiring a notice to the Executive Officer of information that ARB has previously confirmed in writing is permissible for release to the regulatory agency identified in section 95914(c)(1)(A)-(D)specifically required or authorized by the regulatory agency pursuant to any of its applicable rules, orders, or decisions. In the event of a disclosure pursuant to this section, the entity regulated by the agency must provide to the Executive Officer within 10 business days, the statutory or regulatory reference or the general order, decision, or ruling to ARB that requires the disclosure of the specific information, unless ARB has previously confirmed in writing that release of the information is permissible. (SEMPRA 4)

Response: Staff believes that the information referred to in section 95914(c)(2)(D) is clear, per the language in section 95914(c)(2) that states: "Auction participation information listed in section 95914(c)(1) may be released under the following conditions…" Section 95914(c)(2)(D) gives permission to make the information disclosure, and no further written permission by ARB is needed. All that is required is that the entity inform ARB's Executive Officer of the statutory or regulatory provision or general rule, order or decision by another California state regulatory body that required or authorized the disclosure. Staff believes this is needed for each such disclosure so that we know the information has been disclosed and are able to determine that the disclosure was in fact required or authorized by another agency's regulations and rules. Staff therefore declines the opportunity to make the suggested change in the regulatory text.

H-4.24. Comment: The proposed amendments to Section 95914(c)(3)(B) would require covered entities to disclose Consultants and Advisors that provide a broad list of enumerated services relating to the Cap- and-Trade or the Mandatory Reporting Regulation. Beyond the disclosure requirement, covered entities would also be required to ensure that the Consultant or Advisor does not transfer information to other auction participants or coordinate a bidding strategy with other auction participants. Section 95914(c)(3)(B) would specifically require a covered entity to inform its Consultants and Advisors of the prohibition of sharing information to other auction participants and ensure the Consultants and Advisors have read and acknowledged the prohibition under penalty of perjury. It is not clear whether the ARB expects that a covered entity would enforce this prohibition by imposition of an acknowledgement under penalty of perjury or whether the ARB would hold the covered entity responsible for a prohibited disclosure.

The ARB should clarify in revised language, or, in the alternative, in the Final Statement of Reasons that a covered entity's only responsibility is to obtain a signed acknowledgement of the prohibition from its Consultants and Advisors. The covered entity should not be held responsible for a disclosure of their confidential information that is outside of the covered entity's control and outside the scope of work and authority for the Consultant or Advisor. Moreover, the covered entity should not be required to police the activities of its Consultants and Advisors when the Consultants and Advisors are working for other customers or clients**.** (TID 3)

> **Response:** Staff notes that section 95914(c) as a whole prohibits the sharing of information regarding bidding strategy, intent to participate in an auction, bid price, and bid guarantee information. This prohibition applies to registered entities, corporate associations, and Cap-and-Trade Consultants and Advisors (see section 95923 for references to the services a Consultant/Advisor could perform to meet the regulatory definition). Section 95914(c)(3) requires those Consultants/Advisors providing advice on bidding strategy (which encompasses information essential to bid strategy – such as bid price, bid guarantees, etc.) to disclose the information in subparagraph (C) to ARB. Thus, the reference to "auction bidding strategy" is intended to make entities and Consultant/Advisors engaged in developing bidding strategy for the entity cognizant of the prohibitions on information sharing. Both parties are expected to exercise due diligence and care to avoid sharing highly sensitive auction information with other auction participants.
>
> In addition, staff would like to make clear that a signed acknowledgement of the prohibition of information sharing from Consultants and Advisors that are providing auction bidding advice is the first of several steps that entities could take to minimize the release of confidential auction information listed in section 95914(c)(1). Staff leaves it to entities and Consultants and Advisors to determine and implement other reasonable steps that may or may not be part of their contractual arrangements, designed to protect entity confidential information held by Consultant/Advisors. Staff declines to revise the regulatory text as suggested by the commenter.

H-4.25. Comment: SCE supports the ARB's decision to modify Section 95914(c)(2)(D) of the Cap-and- Trade Regulation to allow disclosures of confidential auction information by investor-owned utilities as required by the CPUC. However, it is unnecessarily burdensome to require regulated entities to provide the ARB with a justification for the disclosure within 10 business days of each disclosure. The utilities regularly receive data requests from regulatory agencies relating to their procurement activity. Requiring the utilities to report each auction-related disclosure to the ARB and to provide statutory or regulatory references for each occurrence would be burdensome, impracticable and, in many cases, redundant.

Recommendation: SCE, therefore, suggests the following changes to the second sentence of Section 95914(c)(2)(D) of the 15-Day Modifications, which, in essence, revert to language that the ARB proposed in its January 2014 Informal Discussion Draft on Proposed Amendments to the California Cap-and-Trade Regulation:

In the event of a disclosure pursuant to this section, **upon request of the Executive Officer** the entity regulated by the agency must provide ~~to the Executive Officer within 10 business days,~~ the statutory or regulatory reference or the general order, decision, or ruling to ARB that requires the disclosure of the specific information related to bidding strategy **within 10 business days of such request**.

Moreover, SCE encourages the ARB to continue to work with the CPUC to better understand disclosure requirements for investor-owned utilities. (SCE 4)

Response: Staff believes that the information referred to in section 95914(c)(2)(D) is clear, per the language in Section 95914(c)(2) that states: "Auction participation information listed in section 95914(c)(1) may be released under the following conditions…" Section 95914(c)(2)(D) gives permission to make the information disclosure, and no further written permission by ARB is needed. All that is required is that the entity inform ARB's Executive Officer of the statutory or regulatory provision or general rule, order or decision by another California state regulatory body that required or authorized the disclosure. Staff believes this is needed for each such disclosure so that we know the information has been disclosed and are able to determine that the disclosure was in fact required or authorized by another agency's regulations and rules. The suggested change to the regulatory text would effectively have the same result, as ARB staff would have to routinely issue a request to the commenter and others regarding auction participation and bidding strategy disclosures required under regulatory order, decision or rule. As noted in prior responses, staff is willing to work with entities subject to this section of the Regulation to minimize the work required by reporting while still providing the information that staff believes is important to market oversight. Staff will also be working with the CPUC staff on this and other issues. Staff therefore declines to make the suggested change in the regulatory text.

H-4.26. Comment: Proposed §95914(c)(3)(A) states that "If an entity participating in an auction has retained the services of a Cap-and-Trade Consultant or Advisor, as defined in section 95923, *regarding auction bidding strategy* [emphasis added], then the entity must take specified actions to prevent transfer of bidding strategy to other auction participants or coordinating bidding strategy among participants. LADWP supports this proposed language. (LAWDP 3)

Response: Staff appreciates support for this 15-day change in the text of section 95914(c)(3)(A).

H-4.27. Comment: Section 95914(c)(3)(A) and (B) have been further amended to remove the requirement that any entity that has retained the services of a Cap-and-Trade Consultant or Advisor must inform ARB of the advisor's retention, "and identify the Consultant or Advisor...and provide an attestation by the Primary Account Representative of the entity retaining the advisor..."

SGEN agrees with this modification, but further modification is required. This amendment continues to be duplicative of the requirement that an entity disclose retention of a Consultant or Advisor under section 95923(b) and (c) when registering with ARB, within 30 days of entering into a contract with a Cap-and-Trade Advisor or Consultant, and within 30 days of a change to any previously reported information regarding a Cap-and-Trade Advisor or Consultant. Further, to impose an obligation on a "Consultant or Advisor" who has clients participating in the Cap- and-Trade Program to inform ARB 15 days prior to each carbon auction of the names of its clients and the advisory services being performed, and specify that this information be Section 95914(c)(3) should be removed from the proposed amendments. (SEMPRA 3)

> **Response:** Staff respectfully disagrees that this amendment is duplicative of the entity disclosure required in section 95923(b); the commenter correctly understands, per the first paragraph of its comment, that entity disclosure requirements for Cap-and-Trade Consultants and Advisors have been removed from section 95914(c)(3). Staff also disagrees that it is unduly burdensome to require Consultant/Advisors to inform ARB of their clients, advisory services, etc., prior to each auction. Staff will provide written guidance on this reporting requirement with the intent of clarifying the reporting burden while still satisfying ARB's need for this information as part of our allowance market oversight. Staff declines the request to delete section 95914(c)(3).

Cap-and-Trade Consultants and Advisors

H-4.28. Comment: CARB has slightly modified provisions first introduced in September that would require entities registered in the cap and trade program to disclose the names of individuals or entities providing services related to the cap and trade program. These modifications appear to expand the scope of this provision further, as the provisions is explicitly not limited to consultants providing offset or verification services. WPTF notes that lists provided in section 95979(b)(2) of the regulation and 951333(b)(2) of MRR (which 95923 includes by reference) cover a broad range of services. We consider the breadth of these lists to be appropriate given the need to identify possible conflicts of interest of staff for verification bodies. However, we do not believe that responsibility for identifying conflicts of interest in verification staff should also fall on covered entities. Therefore, we do not consider identification of potential conflicts of interest to be a valid objective for section 95923.

Rather, in keeping with the approach we recommend for disclosure of employees of registered entities in section 95839(I), WPTF considers that the objective of 95923 should be to identify consultants and advisors with the ability to either influence an registered entities transactions of compliance instruments, or who have access to information on these holdings and transactions of compliance (and, because of their status as consultants and advisors, could be in position to share this information with other registered entities).

As with requirements for employee disclosure in section 95839(l), WPTF considers it inappropriate for CARB to require disclosure of consultants and advisors who provide services relating to GHG assessment or auditing, inventory development, internal mitigation projects, reporting, or similar. Such services are a normal and integral part of registered entities' business operations and would be conducted in the absence of the cap and trade program. Further, because information on entity's covered emissions will be made publicly available, a consultant or advisor's access to information related to these emissions will not convey any market advantage.

WPTF recommends that, rather than referencing section 95979(b)(2) of this regulation and 95133(b)(2) of the MRR, that staff modify section 95923 to designate an exclusive list of services, as follows:

95923. (a) A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is providing the services listed in section 95979(b)(2) of the Cap-and- Trade Regulation or section 95133(b)(2) of the Mandatory Reporting Regulation in relation to the Cap-and-Trade Program or MRR <u>below</u> specifically for the entity registered in the Cap-and-Trade Program, regardless if the Consultant or Advisor is acting in the capacity of an offset or MRR verifier.

(1) Services that result in the consultant or advisor having access to information on the entity's holdings or transactions of compliance instruments; and
(2) Services that result in the consultant or advisor having authority to transact compliance instruments on behalf of the entity. (WPTF 3)

> **Response**: Staff assumes the reference to section 95839(l) is meant to refer to section 95830(c)(1)(l). Staff does not agree with the proposed modification to section 95923 to more closely resemble section 95380(c)(1)(l) as this would exclude the disclosure of individuals that have the authority to impact an entity's market position but that do not directly transact compliance instruments. In the 15-day comment period, section 95923 was modified to reduce the administrative burden on entities but still allow for the disclosure of individuals that have access to information related to an entity's compliance strategy, not limited to holdings or transactions of compliance instruments. The disclosure of these individuals is required for market monitoring and to identify any entities that may be linked through a consultant or advisor and thus have the ability to manipulate the market.

H-4.29. Comment: Today, we write on our own behalf to provide comments on Section 95923 of the Proposed 15-Day Amendments to the California Cap on Greenhouse Gas

Emissions and Market- Based Compliance Mechanisms (the “15-Day Proposal”). Proposed Section 95923 deals with consultants and advisors to entities registered in the cap-and-trade program.

As currently worded, the 15-Day Proposal would require any entity “employing” a “Cap-and-Trade Consultant or Advisor” to disclose the name, contact information, physical address and employer of such consultant or advisor to ARB. Section 95923(b). “Cap-and-Trade Consultant or Advisor” is defined as a person or entity that is not an employee of an entity registered with ARB and that provides the services listed in Section 95979(b)(2). Section 95923(a). Section 95979(b)(2) sets forth a long list of services and explicitly includes “legal services”. Although it is possible to interpret the introductory langue in Section 95979(b)(2) as limiting the types of services referenced in Section 95923(b), it is also possible to interpret such reference as one covering all legal services without limitation of the nature or the parties involved in the provision of the services. If the latter interpretation is not ARB’s intent, we urge ARB to clarify the wording of proposed Section 95923(b). If, indeed, ARB is proposing to require cap-and-trade program registrants to disclose the identity of their outside counsel, we would like to object to the proposal, for the reasons set forth below.

We strongly believe that requiring the disclosure of the identity of outside counsel in connection with the cap-and-trade program is both unnecessary and potentially harmful. It is unnecessary because the provision of legal services is already highly regulated, and subject to the laws of each state and the local ethics rules of each state’s bar. It is potentially harmful because confidentiality within the attorney-client relationship, including, in some cases, the existence of the relationship, is a foundational principle of legal ethics designed to encourage clients to seek legal advice. Disclosing the attorney-client relationship to a public agency could affect the privileged nature of our communications in a manner that would be detrimental to our clients.

We are grateful that ARB has already made improvements to Section 95923 by removing the previously-proposed requirement to disclose a brief description of the services provided by the advisors, but even the existence of an attorney-client relationship can be sensitive information. Although providing the name, contact information and work address of a lawyer would in some cases seem innocuous, there are many instances in which the knowledge that a particular lawyer is working for a particular client would allow competitors, regulators, and other observers to infer the purpose of the engagement to the client’s detriment.

Confidential information such as the existence of an attorney-client relationship is protected by privilege, but to maintain that privilege, that information must be kept confidential and not shared with third-parties. While the information required by proposed Section 95923 is not extensive, any information shared with a party outside the attorney-client relationship creates a risk of damaging the privilege protections which are so essential to the functioning of that relationship. Once attorney-client communications have lost their privilege protections, they could be lost not only with respect to the ARB, but also with respect to competitors, other regulatory bodies, and other parties who may become adverse to the client in the future.

Fortunately, the ethical rules governing attorney-client relationships serve the same policy ends as ARB's proposed Section 95923. Typical of these rules is California Civil Code Section 6068(e), which requires an attorney to "maintain inviolate the confidence, and at every peril to himself or herself to preserve the secrets of his or her client." California's Rules of Professional Conduct – like those of other states – also prohibits counsel from advising "the violation of any law, rule or ruling of a tribunal". Rule 3-210, Cal. Rules of Professional Conduct. In short, the attorney-client relationship is already governed by extensive and well- developed regulations created and enforced by the legal profession. Layering disclosure requirements on top of this existing system unnecessarily complicates the attorney-client relationship and creates the potential for a conflict between the cap-and-trade regulations and the existing ethical rules governing the practice of law.

For the foregoing reasons we urge ARB not to require cap-and-trade registrants to disclose the identity of their outside counsel providing legal services in connection with the program. This can be achieved by modifying the 15-Day Proposal in a number ways, including by exempting "legal services" in Section 95979(b)(2)(R) from the types of services referenced in proposed Section 95923(a). (LW)

H-4.30. Comment: ARB has slightly modified provisions first introduced in September that would require entities registered in the Cap-and-Trade Program to disclose the names of individuals or entities providing services related to the Cap-and-Trade Program.

TransAlta considers that the objective of 95923 should be to identify consultants and advisors with the ability to either influence a registered entity's transactions of compliance instruments, or who have access to information on these holdings.

> **Recommendation:** TransAlta recommends that, rather than referencing section 95979(b)(2) of this regulation and 95133(b)(2) of the MRR, ARB modify section 95923 to designate an exclusive list of services, as follows:
>
> 95923. (a) A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is providing the services listed ~~in section 95979(b)(2) of the Cap-and- Trade Regulation or section 95133(b)(2) of the Mandatory Reporting Regulation in relation to the Cap-and-Trade Program or MRR~~ <u>below</u> specifically for the entity registered in the Cap-and-Trade Program, ~~regardless if the Consultant or Advisor is acting in the capacity of an offset or MRR verifier.~~
>
> <u>1. Services that result in the consultant or advisor having access to information on the entity's holdings or transactions of compliance instruments; and</u>

2. Services that result in the consultant or advisor having authority to transact compliance instruments on behalf of the entity (TA)

Response: Staff does not agree with the proposed modification to section 95923 as this would exclude the disclosure of individuals that have the authority to impact an entity's market position but that do not directly transact compliance instruments or have knowledge of compliance instrument holdings. In the 15-day comment period, section 95923 was modified to reduce the administrative burden on entities but still allows for the disclosure of individuals that have access to information related to an entity's compliance strategy, not limited to holdings or transactions of compliance instruments. The disclosure of these individuals is required for market monitoring and to identify any entities that may be linked through a consultant or advisor and thus have the ability to manipulate the market. See also response to 45-day comments H-1.11.

H-4.31. Comment: The need to collect data about individuals consulting and advising registered entities on matters regarding the Program must be balanced with unduly broad reporting and disclosure requirements. Just as the scope of entities reported under 95914(c) should be directly linked and limited by the bidding counsel provided, so should the definition of Cap-and-Trade Consultants and Advisors be limited to "*contractors that have access to tracking system account information, compliance instrument procurement, and emissions obligations.*"3 M-S-R appreciates the additional refinement of the definition set forth in the 15-Day Changes that further limit the disclosure of Cap-and-Trade Consultants and Advisors to those companies and individuals that provide counsel "in relation to the Cap-and-Trade Program or MRR, specifically for the entity registered in the Cap-and-Trade Program . . ." The 15-Day Changes also properly remove the provision in the earlier proposal that would have required registered entities to provide a description of the services being provided by the Consultant or Advisor (section 95923(b)(2)). (MSR 2)

Response: Thank you for the comment and support of the proposed amendments.

H-4.32. Comment: Proposed §95923 requires disclosure of cap-and-trade consultants and advisors that provide services listed in section 95979(b)(2) of the cap-and-trade regulation or section 95133(b)(2) of the MRR. Although Section 95979 is related to conflict of interest requirements for verification bodies and offset verifiers for verification of offset project data reports, the proposed reference to 95979(b)(2) in section 95923 would require an entity to disclose cap-and-trade advisors and consultants that have provided *non-offset verification services over the past five years* and there is a list of *twenty* non-offset verification services that would apply. Per this proposed definition, this could include attorneys and consultants who provide services unrelated to the cap-and-trade program. The provision should only apply to consultants and advisors who are aware of an entity's compliance instrument position or strategy with respect to procurement or sale of compliance instruments similar to §95914(c)(3)(A).

Recommendation: Thus, LADWP recommends that §95923 be clarified as follows:
A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is providing the types of services in relation to the registered entity's Cap-and-Trade Program auction bidding strategy in section 95979(b)(2) of the Cap-and-Trade Regulation or section 95133(b)(2) of the Mandatory Reporting Regulation specifically for the entity registered in the Cap-and-Trade Program. (LADWP 3)

Response: As indicated in the Staff Report, the purpose of section 95923 is broader than simply auction bidding strategy; section 95914 specifically relates to auction bidding strategy. As such, ARB staff declines to make the requested change, which does not align with the section's purpose. See also response to 45-day comments H-1.11.

H-4.33. Comment: H. Section 95923: Definition of Cap-and-Trade Consultant or Advisor IETA objects to the inclusion of legal services within the new disclosure requirement for cap-and- trade consultants and advisors in section 95923. Confidentiality is fundamental to the practice of law, and our members have a legitimate expectation that their relationships with their outside counsel will remain confidential – including, at times, the existence of such a relationship itself. Disclosure of these relationships could operate to waive attorney-client privilege in certain cases, which could create a disincentive to retaining counsel in the first place and hinder program participants' ability and efforts to seek a better understanding of and comply with the program.

Moreover, we do not believe that disclosure is necessary to ensure the integrity of the cap-and- trade program. Attorneys are independently subject to existing legal and ethical rules – rules that prohibit them from advising their clients to disobey the law and require them to maintain client confidences. These existing rules already operate to prevent lawyers from engaging in activities that could compromise the cap-and-trade market.

As a practical solution to this issue, ARB should exempt persons or entities providing legal services from the definition of "Cap-and-Trade Consultant or Advisor" in the proposed Section 95923. (IETA 2)

Response: See response to 45-day comments H-1.11.

H-4.34. Comment: Throughout this rulemaking process, staff has sought to expand the definition and related disclosure requirements associated with individuals and companies providing entities registered in the Compliance Instrument Tracking System Service (CITSS) with guidance regarding the Cap-and-Trade Program. As noted in earlier oral and written comments from several stakeholders, it is important that the ultimate definition adopted by the Board not be so expansive as to create an entire bureaucracy dedicated to tracking these consultants and advisors. As revised in the 15-Day Changes, the definition of Cap-and-Trade Consultants and Advisors properly strikes a requirement to provide a brief description of the work to be done by the consultants and advisors. The definition, however, has also been expanded to invoke the conflict of interest provisions applicable to verification bodies and offset verifiers pursuant to Section 95979(b)(2) of the Regulation and section 95133(b)(2) of the Mandatory Reporting Regulation (MRR).

Section 95923(a) now defines a Cap-and-Trade Consultant and Advisor as a person or entity that is not an employee of an entity registered in the Cap-and-Trade program, but is providing the services listed in section 95979(b)(2) of the Cap-and-Trade Regulation or section 95133(b)(2) of the Mandatory Reporting Regulation in relation to the Cap-and- Trade Program or MRR, specifically for the entity registered in the Cap-and-Trade Program . . ." This language is tempered from what was in the Discussion Draft by the inclusion of "*in relation to the Cap-and-Trade Program or MRR*," but still encompasses a broad range of individuals and companies. NCPA appreciates CARB's recognition that the definition was too far reaching, and supports the qualification that the individuals and companies must be specifically employed to provide those services relevant to the Cap-and-Trade Program or MRR. In Attachment A of Resolution 13-44, staff noted that they would "*coordinate with stakeholders to craft regulatory language to limit this disclosure requirement to contractors that have access to tracking system account information, compliance instrument procurement, and emissions obligations.*" As currently drafted, even with the limiting language, the proposed definition of Cap-and-Trade Consultant and Advisors reaches beyond those individuals and companies that "*have access to tracking system account information, compliance instrument procurement, and emissions obligations.*" Accordingly, NCPA urges staff to continue to monitor this requirement, and in the event that it appears to result in the submission of unnecessary information or disclosures, revisit the requirements in a subsequent review of the Regulations. (NCPA 3)

> **Response:** Thank you for the comment. Staff is committed to monitoring the disclosure of Cap-and-Trade Consultant and Advisors and ensuring that market monitoring does not present an undue administrative burden nor inadvertent violation of the Regulation.

H-4.35. Comment: SGEN agrees that the term "Cap-and-Trade Consultant or Advisor" ("Advisor") should be defined within the Regulations. However, the language in section 95923(a) as proposed inappropriately suggests that the duties listed within section 95979(b)(2) of the Cap-and-Trade Regulation and section 95133(b)(2) of the MRR are to be considered duties that would classify someone as an Advisor. These referenced sections contain lists of duties a consultant may provide to an entity, but the inclusion of these duties in the definition of an Advisor is overly broad and does not provide the clarity needed regarding the functions performed by an Advisor in the context of participation in the Program.

In its 'Initial Statement of Reasons' issued September 4, 2013, staffs rationale for defining the role of an Advisor was to "differentiate between employees of firms and consultants or advisors, and also to clarify that consulting or advisory services are not publication services available to subscribers but specific services for the entity registered in the cap-and-trade program." The proposed amendments to this section remove the reference to "paid for information or advice related to the Cap-and-Trade Program," yet continue to reference the panoply of duties listed within section 95979(b)(2) of the Cap-and-Trade Regulation and section 95133(b)(2) of the MRR, which goes well above and beyond those that should classify one as an Advisor. Section 95923(a) should be revised to state as follows in order to avoid confusion when reporting the formation or termination of an advisor-client relationship:

A "Cap-and-Trade Consultant or Advisor" is a person or entity that is not an employee of an entity registered in the Cap-and-Trade Program, but is retained by the entity to provide information or advice specific to the entity's auction bidding strategy, carbon instrument transactions, or assessment of the entity's holdings of carbon instruments. Section 95914(c)(3) should be removed from the proposed amendments. (SEMPRA 3)

> **Response:** Staff does not agree that section 95914(c)(3) should be removed from the proposed amendments as it is necessary to prevent the disclosure of information related to auction bidding strategy. Staff does not agree with the proposed modification of section 95923(a) as it is overly restrictive and prevents the disclosure of individuals that may have knowledge of an entity's compliance strategy that can be used to collude with other entities and/or manipulate the market. Staff is committed to monitoring the disclosure of Cap-and-Trade Consultant and Advisors and ensuring that market monitoring does not present an undue administrative burden nor inadvertent violation of the Regulation.

H-4.36. Comment: Under proposed section 95923(c)(2), a company: "must disclose the information pursuant to section 95923(b) to the Executive Officer …[w]ithin 30 days of a change to the information disclosed on Consultants or Advisors." Under§ 95923(a), "[a] 'Cap-and-Trade Consultant or Advisor' is a person or entity that is not an employee of an entity … but is providing services listed in § 95979(b)(2)." Section 95979(b)(2)(R) is "any legal services." According to this language, under a circumstance where ARB threatened an enforcement action against an entity, that entity would presumably be required to provide ARB with the name, "contact information," and "physical work address" of any lawyer spoken to within 30 days. ARB's proposed rules would be violated if the entity did not disclose information regarding how it plans to defend against an allegation of violation. Under proposed § 95914(c)(3)(0), "[i]f an entity participating in an auction has retained the services of a Cap-and-Trade Consultant or Advisor, as defined in Section 95923, regarding auction bidding strategy, then … The Consultant or Advisor must provide to the Executive Officer, the following information: … Description of advisory services being performed." These regulations would require an attorney to disclose to ARB information concerning the advice it has given to its client on participating in the Cap-and-Trade program auctions.

Communications between an attorney and his or her client are privileged. California Evidence Code § 954. California Business & Professions Code 6068(e)(1) requires every California lawyer "To maintain inviolate the confidence, and at every peril to himself or herself to preserve the secrets, of his or her client." Accordingly, it would be against the law for an attorney to perform proposed§ 95914(c)(3)(D). Even the potential existence of counsel or counsel's advice is not a proper subject of inquiry by the government. Attorney-client communications are privileged and inviolate and should only be disclosed to ARB at the sole discretion of the entity holding the privilege.

Accordingly, "any legal services" should be specifically *excluded* from the services covered by or listed in§ 95923 and 95979(b)(2). The inclusion of legal services is simply unnecessary because attorneys are held to a separate standard of ethics, enforced by the California State Bar, which prohibits conflicts of interest including the type of which ARB is apparently attempting to prevent through its disclosure requirements. California Business & Professions Code §§6035-6038. In addition to removing "any legal services" from listed services, the regulation should include a specific disclosure exemption for attorney-client privileged communication or attorney work product. (PACIFICORP 2)

> **Response:** See response to 45-day comments H-1.11.

H-4.37. Comment: We also ask that there be little further review of the definition of cap and trade consultants and advisors as we move forward and see this definition implemented. We think that it should be narrowly interpreted. We support and appreciate the bidding strategy language being added to the Section 95914. And we also appreciated very much hearing in staff's presentation that those disclosures are not intended to compromise any attorney-client privileges but believe these sections could be further reviewed and fine-tuned in the context perhaps of the fall rulemaking. (NCPA 4)

> **Response:** Thank you for the comment. Staff is committed to monitoring the disclosure of Cap-and-Trade Consultant and Advisors and ensuring that market monitoring does not present an undue administrative burden nor inadvertent violation of the Regulation in regards to the release of information related to auction bidding strategy.

Jurisdiction

H-4.38. Comment: ARB previously proposed the following language in 96022(c): “A party that has rights and protections under the Foreign Sovereign Immunities Act consents to civil enforcement of the laws, rules and regulations pertaining to this article in California’s courts, subject to the rights and protections afforded to entities subject to the Foreign Sovereign Immunities Act, including removal to federal court.” This language would create cross-jurisdictional double-jeopardy for affected compliance entities by making it possible to legally try them in both California and in the linked jurisdiction. Strike or revise this language to make it clear that an entity that is subject to another jurisdiction linked to the California program cannot be tried in either California or U.S. Federal court (if the entity is a non-US entity). (WSPA 5)

> **Response:** This comment is outside the scope of the proposed amendments, so no response is required. However, since the commenter posed the same comment during the 45-day comment period, ARB staff responded as follows: As stated in the Initial Statement of Reasons, this provision was added to ensure that rights held by entities pursuant to the Foreign Sovereign Immunities Act are not being abrogated by the regulation. Entities participating in the California program are subject to the requirements in California; those participating in a linked jurisdiction would be subject to those requirements. The recommendation by the commenter mistakes the purpose of the regulatory provision and the rights available under the Foreign Sovereign Immunities Act. As such, staff declined to make the requested change.

H-5. Voluntarily Associated Entities

H-5.1. Comment: Newly proposed section 95814(a)(7) provides: "An individual employed by an entity subject to the requirements of MRR or the Cap-and-Trade Program is not eligible to register as a voluntarily associated entity." Since CARB intends to restrict all employees of covered entities from registering as voluntarily associated entities, the need to report additional information regarding employees with knowledge of trading instruments (see Section 95830(c)(1)(I)) appears to be unnecessary, and therefore, should be removed. NCPA also urges the Board to direct that the regulatory language be further refined to apply the restriction to individuals employed by "covered entities or opt-in covered entities," as that language is more certain than "subject to the requirements of MRR or the Cap-and-Trade Program."

The 15-Day Changes create internal inconsistencies in the Regulation relevant to the ability of Cap-and-Trade Consultants and Advisors (CTCAs) to register as voluntarily associated entities. Section 95814(a)(3) includes a list of individuals that can register as voluntarily associated entities if they submit a notarized letter from their employer consenting to the registration. New language in section 95814(a)(3) adds employees of entities "providing consulting services as described in section 95923" to this list. This addition, however, is at odds with language in section 95814(a)(6) that includes cap-and-trade auction advisors in the list of individuals that are *not* eligible to register as voluntarily associated entities, with no reference to the qualifier added to section 95814(a)(3). Prior to adoption, the language must be revised to clarify the extent to which CTCAs may register as voluntarily associated entities, including whether or not the prohibition is intended to apply only to CTCAs who provide advice on bidding strategies, as defined in 95914 (formerly "auction advisors"). (NCPA 3)

> **Response:** Section 95830(c)(1)(I) addresses concerns beyond the scope of new section 95814(a)(7) and is therefore necessary. Section 95830(c)(1)(I) is

intended to identify employees with access to an entity's market position for market monitoring to identify relationships between entities and prevent market manipulation. Section 95814(a)(7) prohibits employees from registering as Voluntarily Associated Entities but does not require entities to report employees that have access to information about the entity's market position. Therefore both sections are necessary.

Staff does not agree with the proposed amendment that would limit the prohibition in section 95814(a)(7) to covered and opt-in covered entities. Staff feels it is important to prevent employees of EDUs and entities required to report production and emission data via MRR from registering as Voluntarily Associated Entities in the Cap-and-Trade Program.

H-5.2. Comment: LADWP supports CARB's action to strengthen the VAE provisions. LADWP believes that the proposed requirement prohibiting individuals employed by a covered entity from registering as a VAE would address CARB's concern that individuals with access to potential market-related data would use that information for personal gain. Since proposed §95814(a)(7) prohibits any individual employed by an entity subject to the MRR or the Cap-and-Trade Program from registering as a VAE, LADWP believes that there is no need for §95830(c)(1)(I) which requires covered entities to provide a list of names and contact information for all persons employed by the entity with knowledge of the entity's market position (current and/or expected holdings of compliance instruments and current and/or expected covered emissions). (LADWP 3)

Response: Section 95830(c)(1)(I) addresses concerns beyond the scope of section 95814(a)(7) and is therefore necessary. Section 95830(c)(1)(I) is intended to assist in market monitoring and the identification of corporate associations. This is not covered in section 95814(a)(7) and therefore both sections are necessary.

I. COST CONTAINMENT

I-1. Proposed Additional Cost Containment Mechanisms

I-1.1. Comment: We also support the cost containment provisions, but we ask that CARB further explore a suite of measures that can be adopted and that the Board direct that further work on transitioning to a post-2020 cap and trade begin sooner rather than later. We also support the clarification of permissible disclosures of auction-related information under limited conditions and the inclusion of the resource shuffling provisions that incorporate the current guidance language and remove the attestation requirements. These changes are necessary to take into account the interaction between the Cap and Trade Program and the State's other GHG objectives, including SB 1368, and believe incorporating the guidance language that was drafted by staff and worked On by a lot of diverse stakeholders is the right route to take. (NCPA 4)

> **Response:** These comments are outside the scope of the proposed amendments, so no response is required. See also response to 45-day comment I-1.2.

I-1.2. Comment: ARB previously proposed the following language: “The allowances defined in section 95870(j)(1) will be sold beginning with the latest vintage and then the preceding vintages, from latest to most recent, until all accepted bids at the highest price tier are filled or until all the allowances defined in section 95870(j)(1) have been sold.” In the interest of cost containment, it appears ARB has agreed to provide “additional” allowances, by taking from later vintage years and making them available earlier, without replacing the later vintage years’ allowances. We remain concerned that this approach does not provide “additional” allowances. Rather, it merely creates the potential for a shortage of allowances in later years and possible price volatility.

WSPA recommends ARB delete this requirement. In lieu of the proposed language ARB should evaluate whether and to what extent longer-term potential imbalances exist between allowance supply and demand. WSPA suggests that ARB’s evaluation include economic and legislative reports and that ARB establish a mechanism by which it could provide new, additional allowances to the market to prevent prices from exceeding the highest price in the APCR. ARB should further study other means of increasing the supply of compliance instruments, such as offset carryover across compliance periods, the redistribution of unused offsets, and expanding the offset market geographically and temporally. (WSPA 5)

> **Response:** These comments are outside the scope of the proposed amendments, so no response is required. See also response to 45-day comment I-1.5.

I-1.3. Comment: As stated in IETA’s previous January 2014 submission, IETA supports ARB’s proposal (as an initial first step) to make available 10% of future allowance budgets, as needed, at reserve sales once per year starting in 2015 at the highest price tier of the Allowance Price Containment Reserve (APCR). This provision may provide some short-term relief in the case that prices rise unexpectedly. However, IETA does not believe that this provision adequately satisfies the Board Directive to prevent allowance prices from rising beyond the APCR, particularly in the case of an extended period of high demand due to unforeseen market dynamics or economic imbalances. Ultimately, it is in ARB and IETA's interest alike to ensure that prices do not rise so high that the Governor feels pressure to step in and exercise his/her right to suspend the cap-and-trade program.

IETA encourages ARB to re-visit the proposals originally discussed at the 25 June 2013 Public Workshop (including those by ARB, EMAC, and the Joint Utilities Group2), which explored a number of innovative options that would serve to keep prices below the highest-tier APCR price, while at the same time maintain environmental integrity.

In particular, IETA considers two options presented at the 25 June 2013 workshop to be worth further consideration:

Expanding offset supply would be an effective means of containing the cost of the cap-and-trade program, while also ensuring environmental integrity of the program.

Additional low-cost compliance options could be introduced into the system through offsets in a variety of ways, but first and foremost is ensuring that offset supply meets demand. That can be done through the timely development and adoption of additional compliance offset protocols such as the Mine Methane Capture protocol (more on this below).

Aside from the adoption of additional protocols, two relatively simple options to increase the effectiveness of offsets as a cost containment mechanism are: 1) expand entity compliance limits beyond 8%; or 2) allow entities to carry over unused offset limits from one compliance period to the next.

If faced with an extreme case where keeping prices below the highest tier of the APCR was proving difficult, ARB could have a provision ready to kick in that allowed the creation of additional allowances to be sold at the highest tier price, providing crucial cost relief.

In order to maintain environmental integrity, the state of California could use revenue from the sale of these additional allowances to buy and then retire quantifiable and certified allowances from third party greenhouse gas reduction programs (such as the Regional Greenhouse Gas Initiative (RGGI)). Meaning that for each additional California Carbon Allowance (CCA) that ARB created and sold, a corresponding RGGI allowance would be retired. California could even choose to implement a quota system where for each additional CCA it created it would retire (for example) three RGGI allowances.

Not only would such a system provide cost relief and maintain environmental integrity, it would also serve to indirectly link its market to other markets – a goal outlined in AB32 to build regional and international markets. IETA would be pleased to work with ARB moving forward in this pursuit. (IETA 2)

> **Response:** These comments are outside the scope of the proposed amendments, so no response is required. However, see also response to 45-day comment I-1.10.

I-1.4. Comment: The 15-Day Changes do not further refine the proposed amendments regarding ways in which to control the price of allowances for covered entities in the event that the price of allowances exceeds the highest tier of the Allowance Price Containment Reserve. NCPA concurs with the many and diverse interests that support the cost containment provisions of section 95913(f)(5), and also urges Staff to begin looking at further cost containment matters prior to the third compliance period. (NCPA 3)

> **Response:** The comment is outside the scope of the proposed amendments, so no response is required. However, see also response to 45-day comment I-1.18.

J. MINE METHANE CAPTURE COMPLIANCE OFFSET PROTOCOL

General Support for Protocol

J-1.1. Multiple Comments: We appreciate the opportunity to comment upon the California Air Resources Board's (ARB) Compliance Offset Protocol for Mine Methane Capture (MMC) projects. We believe that the MMC Protocol meets two key criteria that are important to a successful carbon market: the MMC Protocol is both scientifically credible and commercially viable. CVP strongly supports the proposed California Air Resources Board's (ARB) Compliance Offset Protocol for Mine Methane Capture (MMC) projects. (EVANS)

Comment: ARB has constructed a protocol that is scientifically sound, technically robust and practical in its workability and application, which should all result in measurable, real and permanent reductions in greenhouse gas emissions. (BLUESOURCE 2)

Comment: SCI supports ARB's efforts to reduce global greenhouse gas emissions through a healthy and proactive cap and trade system. SCI further believes that methane is a potent greenhouse gas and the MMC protocol will reduce these emissions from US mines. (SOLVAY 2)

Comment: There are currently no incentives to avoid methane emissions and regulations to reduce emissions are not likely in the near term. Regulations will never be as effective as an economic incentive and not implemented as quickly.
Experts are now reporting that methane emissions are the most important greenhouse gas emissions to reduce. Methane is now considered to have a Global Warming Potential twenty five times that of carbon dioxide (CO_2). Methane also is an energy source that if used conserves energy from other sources while reducing greenhouse gas emissions.

The World Bank estimates that 7,500,000,000 metric tons of CO_2 equivalent per year of methane is emitted annually around the world from human related activity. That methane if used for electricity generation for example could produce 250,000,000 Mega Watt Hours per year. Mines in the US typically are pressured to sign electricity agreements prohibiting them from generating any electricity from the naturally occurring methane in their mines. (VESSELS 3)

Comment: This MMC protocol will enable and encourage mines to voluntarily reduce GHG emissions that would otherwise be vented, a requirement by law to ensure miner safety, to the atmosphere. Mitigating these emissions is expensive and would not be achieved without financial compensation. (ECC)

Comment: Biothermica Technologies Inc. (“Biothermica”) would like to thank the California Air Resources Board (ARB) for this opportunity to support the approval of the proposed Mine Methane Capture (MMC) Protocol.

Our support is provided from the perspective of a ventilation air methane (VAM) project developer and technology owner, having developed and implemented the first VAM destruction project at an active mine in the U.S.

Mine ventilation air methane (VAM) emissions are one of the largest sources of non-regulated greenhouse gas emissions in the U.S. Based on the nature of these emissions – high volume but very low methane concentrations – carbon offsets are the most effective way to support the development of VAM abatement technologies. Thanks to the carbon price signal finally provided by the Protocol's adoption, project developers will be able to deploy their innovative methane abatement projects at several U.S. mine sites. This price signal is a crucial factor, considering these projects rely on carbon offsets as a source of revenues. (BIOTHERMICA 2)

Comment: I strongly support implementing protocols to reduce methane from abandoned and active coal mines. I had the opportunity to study about methane flow within coal seams under the guidance of Professor Lynn Orr (nominated by President Obama to be the next Under Secretary of Science at the DOE) at Stanford University as a Ph.D. student in Petroleum Engineering.

During my career at Stanford, we conclusively measured methane seepage through coal seams to the atmosphere as a result of anthropogenic activities. We suspected at the time that such seepage was prevalent all throughout the U.S.

Since graduating from my program, I have made several high-order measurements of methane seeps from coal seams in Colorado, New Mexico, and on Indian Reservations. Our results confirmed that methane seepages from coal seams occur in many states, and at many active and abandoned coal mines. Reducing such emissions would be a positive step towards preventing further increases in GHG concentrations in the atmosphere.

The California Air Resource Board's compliance offset protocol for mine methane projects provides key economic driver that allows methane to be destroyed from leaky coal mines. I fully support the mine methane protocol. (IDE)

Comment: While there is more work to be done, our group of experts recognizes that the California Air Resource Board will be taking a valuable step towards sustainable development of coalmine methane resources by adopting the Compliance Offset Protocol for Mine Methane Capture Projects. This is not only an important step for California; it is important for many countries in the world. Methane is a well-mixed gas in the atmosphere and therefore what is done to reduce emissions of this powerful greenhouse gas in one country undeniably benefits other countries. California, by virtue of its ranking as one of the top ten economies in the world, and its location on the coast of the United States, is inextricably connected to the global economy. Even if California's carbon trading scheme is never directly linked to others throughout the world, it will become a positive environmental, economic, and social influence.

Moreover, providing economic incentives to capture and use coal mine methane saves lives. All coal mining nations have suffered the loss of miners to methane related accidents. These accidents are not inevitable -they are preventable. Lack of investment in effective management of coal mine methane at coal mines is the cause of methane emissions to the atmosphere, waste and destruction of important natural resources, and tragically, accidents that lead to the needless loss of life. These accidents occur not only in developing nations, but also in developed nations such as those that occurred in 2010 in the United States and New Zealand.

Members of the Group of Experts on Coal Mine Methane authored a document entitled "Best Practice Guidance for Effective Methane Drainage and Use in Coal Mines" http://www.unece.org/fileadmin/DAM/energy/se/pdfs/cmm/pub/BestPractGuide_MethDrain_es31.pdf. This document is designed to provide regulators and decision makers a background for principled based actions that if taken, can lead to sustainable development of a resource that is a clean burning fuel if used, or a powerful greenhouse gas if it is vented to the atmosphere. Its capture and utilization positively affects the global environment and that of local communities.

We urge the California Air Resources Board to adopt the proposed protocol which will surely encourage the reduction of emissions of coal mine methane to the atmosphere and contribute to best practices for sustainable energy production (UNECE)

Comment: Where there is coal there is methane. Methane seeps from coal deposits whether the coal is mined or not. Methane from coal is a natural resource that can be hard to capture too. Historically, methane was viewed as a waste product of mining valuable coal. Of the known methane emissions, EPA estimates that less than 25% are being captured and beneficially used.

The proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects encourages use of a natural resource that is being wasted. (TOOLE ONEIL 2)

Comment: The Mine Methane Capture Protocol targets a sector that can contribute a significant US supply of greenhouse gas (GHG) reductions that would otherwise not be controlled. Offset protocols provide the business community and the agency with the assurance that there is a sound technical basis used to create real and permanent emission reductions. (CHEVRON 6)

Comment: WSPA strongly supports the adoption of the new protocols for Coal Mine Methane. (WSPA 5)

Comment: We strongly support the adoption of new methane proposals for coal mine methane. (WSPA 6)

Response: Thank you for the support.

***J-1.2. Multiple C*omments:** Experts are now reporting that Methane is a greenhouse gas with a Global Warming Potential twenty five times that of Carbon Dioxide. Methane also is an energy source that if used conserves energy from other sources and reduces greenhouse gas emissions. The World Bank estimates that 7,500,000,000 Metric Tons of CO2 equivalent per year of methane is emitted annually around the world. That methane if used for electricity generation for example could produce 250,000,000 Megawatt hours per year. There is currently no incentive to avoid methane emissions and rules to reduce emissions are likely to take years and never be as effective as an economic incentive. We have no verifiable estimate of methane emissions over all from active or abandoned mines as the cost of performing detailed surveys is prohibitive. This protocol will encourage the generation of new and accurate data of methane emissions from mines. This could encourage more research and measurement of methane emissions from all sources.

Holy Cross Energy encourages the Board to approve the Mine Methane Capture protocol. (HCE 2)

Comment: This protocol will encourage the generation of new and accurate data of methane emissions from mines. This could encourage more research and measurement of methane emissions from all sources. (WSCC, ENCORE)

Comment: Projects based on this protocol could incentivize mines to use a valuable resource and not purchase electricity at additional expense. In locations where such energy conversion is not economical or practical the MMC protocol will encourage feasibility studies to reduce the emissions by combustion. (VESSELS 3)

Comment: We have no rigorous verifiable estimate of overall methane emissions including emissions from active or abandoned mines as the cost of performing detailed surveys is prohibitive. This protocol will encourage the generation of new and accurate data of methane emissions from mines because the potential value of using and eliminating those emissions. This could encourage more research and measurement of methane emissions from all sources. (TOOLE ONEIL 2)

Comment: The truth is that without action by small companies like ours, millions of tonnes of methane will continue to be vented into the earth's atmosphere. Without an MMC protocol soon, many of these projects we hope to develop will cease to be viable, and you'll be short of offsets. Madam Chairman, distinguished Board members, California is and has always been a leader in environmental issues. And we recognize that being a leader has tremendous challenges. (GREEN 2)

Comment: I want to give you all an example of the effect that the Mine Methane Capture Protocol could have. A few months ago, I was hunting methane seeps and a truck with a specialist with a special methane detector. We were driving along a public paved road. We knew underneath off to the side of the road off one location there was a mine complex more than 200 feet deep. We got out, and the methane detector, we took it over. It's just a narrow wand. You just hold it out and just bring it as close as you can to the earth. We didn't find anything above ambient atmosphere except at one point. For information out here in the west, the methane content -- the ambient methane content is about two parts per million. So we were walking along the bottom of the hillside next to the road, and suddenly, we hit over 3,000 parts per million. And a band about this wide, and it went straight up the hill, further than we cared to climb at the moment.

Now, we think it's unreasonable to assume that that was an isolated seep. This was in an area of historic mining, over thousands of acres. But we also don't think it's possible to go -- we think the technology exists. We certainly found it. And we think we know how to remediate seeps of this nature. But we can't do that without an economic incentive. So we think that your mine methane protocol is going to do a lot both to focus on methane generically and giving us the ability to have an incentive to find those seeps and remediate. (VESSELS 4)

> **Response:** Thank you for the input on how the proposed MMC protocol is likely to assist the collection of data and impact the development of projects and related technologies. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, staff agrees that adoption of the MMC protocol will lead to technological advancements in mine methane capture and destruction that would not occur without the financial incentive provided by the compliance offset protocol.

J-1.3. Multiple Comments: Offset credits represent a crucial cost containment mechanism to help the California cap-and-trade program achieve GHG emission reductions in an economically efficient manner. (ESI, HCE 2, ENCORE, CLIMECO, VESSELS 3)

Comment: Offset credits represent a crucial cost containment mechanism to help support the California cap-and-trade program to achieve GHG emission reductions in an economically efficient manner. (EVANS)

Comment: Furthermore, the offset credits to be generated from the MMC protocol will represent a material contribution to the California cap-and-trade program’s ability to achieve GHG emission reductions in an economically efficient manner. (BLUESOURCE 2)

Comment: Offset credits represent a crucial cost containment mechanism to help the California cap-and-trade program achieve GHG emission reductions in an economically efficient manner. (WREA).

Comment: ClimeCo Corporation strongly supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects. (CLIMECO)

Comment: PG&E Supports the Adoption of Additional Protocols. PG&E would like to reiterate its support for the adoption of additional protocols to provide an adequate supply of offset credits to the cap-and-trade market. The use of high-quality offset credits is an effective cost-containment tool and an essential component of a successful cap-and- trade program. However, as previously stated in PG&E's comments, without adequate supply, the cost-containment benefit of offset credits will not be fully realized. Approval of the MMC protocol is important because it can facilitate the generation of a significant supply of offset credits. While estimates vary, MMC projects have the potential to reduce tens of millions of tons of CO2e from mines whose methane would otherwise be released to the atmosphere. Because U.S. MMC projects can reduce methane emissions without increasing mining, and in doing so generate a significant supply of offset credits to help contain costs for California businesses, PG&E strongly supports the approval of the MMC protocol. (PGE 4)

Comment: Chevron is pleased that ARB is considering adoption of the following policies which represent improvements in the cap and trade program: Mine Methane Capture Protocol and Offsets – Offsets afford California a critical opportunity to meet the AB 32 environmental goals in the most efficient and low cost means possible in sectors that are not regulated. Chevron supports the Mine Methane Capture Protocol as a substantial step towards increasing the supply of offsets. (CHEVRON 6)

Comment: IETA strongly supports the proposed compliance offset protocol for mine methane capture (MMC) projects. Offset credits represent a crucial cost containment mechanism to help the California cap- and-trade program achieve GHG emission reductions in an economically efficient manner. IETA encourages officials to approve and make effective the protocol as soon as possible.

Generally, IETA supports ARB's efforts to develop new protocols that can provide offset credits to supply the market. In addition, we encourage ARB to update and expand existing protocols that can increase supply of already-proven, high-quality offset credits in the near-term. (IETA 2)

Comment: First of all, a few points on offsets. Southern California Edison feels strongly that mine methane protocol is a great thing for you guys to include here. I think ARB staff has proposed a protocol that can provide two clear benefits to us. One is significant supply of offsets to the California Cap and Trade Program, while two, we're incentivizing here the reduction of emissions currently being neglected. As SCE has stated before, a study supply of offsets in the California Cap and Trade Program will help keep allowance prices down in the long run. And this will help moderate compliance costs for California electricity customers. Southern California Edison encourages ARB staff to continue investigating additional protocols for approval, both national and international. (SCE 5)

Comment: This protocol is critical to ensure adequate offset supply to the market for cost containment purposes and to demonstrate California's leadership in reducing greenhouse gas emissions. We strongly encourage the Board to adopt the mine methane capture protocol today. (PGE 5)

Comment: We support the mine methane protocol. We believe offsets are important to keep the cost down, and we don't think we have enough offsets even with the mine methane protocol. (CHEVRON 7)

> **Response:** Thank you for the support. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, we do note that the MMC protocol is the fifth compliance offset protocol approved by the Board and will result in an increased supply of offset credits. The proposed protocol is consistent with the requirements of the Cap-and-Trade Regulation and AB 32 including the objective of achieving cost-effective emission reductions. Staff has estimated that if every entity used their allowable eight percent offsets, approximately 26 million metric tons of offsets would be needed in the first compliance period. Based on the five offset protocols the Board has adopted—livestock digesters, forestry, urban forestry, destruction of ozone depleting substances, and the newly adopted mine methane protocol—ARB believes there will be enough offsets in the program to the supply demand for the first compliance period. Staff is committed to evaluating additional offset types to ensure sufficient offset supply.

General Opposition to Protocol

J-1.4. Multiple Comments: Please cancel the proposed Mine Methane Capture Protocol. Offsets and carbon trading are a false solution to climate change and must be excluded from California's Global Warming Solutions Act AB32. (GLASS, NORRGARD, PERKINS, WATERS, LOURENCO, BARNARD, CUNNINGHAM, LMORRISON, WONG, CMORRISON, SAEGER, MAES, BULLA, THERULES, APEN 2)

Comment: Offsets and carbon trading are a false solution to climate change and must be excluded from California's Global Warming Solutions Act AB32. (ZHOU, WOOD)

Comment: The people of CALIFORNIA and the UNITED STATES DO NOT CONSENT to the proposed Mine Methane Capture Protocol. Offsets and carbon trading are a false solution to climate change and must be excluded from California's Global Warming Solutions Act AB32. (SOPHINA).

Comment. I urge you to cancel the proposed Mine Methane Capture Protocol. Offsets and carbon trading are a false solution to climate change and must be excluded from California's Global Warming Solutions Act AB32. The only thing that can save this planet is conservation. (CHUNG)

Comment. On behalf of Americans against Offsets, I cordially request that you immediately cancel the proposed Mine Methane Capture Protocol. Offsets and carbon trading are a false solution to climate change and must be excluded from California's Global Warming Solutions Act AB32. (AAO)

Comment: Carbon credits and methane flaring are false solutions to the real problem of climate change. (DESENZE)

Comment: California must immediately cancel methane offsets. Climate change is an immediate threat to all of us. (RUBY)

Comment: Cancel methane offsets immediately! (SIGLER)

Comment: We want clean, renewable, sustainable energy now—immediately cancel methane offsets. (GARLENA)

Comment: Please stop California's Global Warming Solutions Act's (AB32) proposed Mine Methane Capture Protocol (MMCP). This is not the kind of environmental solution we need. (BURLEY)

Comment: Irresponsible solutions like offsets and carbon trading not realistic and will damage the environment further. Please cancel your the proposed Mine Methane Capture Protocol.

You all have a responsibility to the environment, animals and future generations. This is your chance to make a difference instead of making your pockets fat. (SOLIZ)

Comment: The clear historical evidence from EU and elsewhere is that offsets reward polluters, fail to reduce emissions at source and frequently fail to be additional. Both the methane mine capture and forestry protocol are particularly ripe for abuse with mining and forestry executives pushing for them in order to expand their industries. California's Global Warming Solutions Act AB32 will turn from a flagship legislation to a laughing stock if these flaws are not addressed. (BUXTON)

Comment: The Protocol represents the advent of a trading commodity – methane offsets. Furthermore, the Protocol stands to be a dangerous prototype for the future development of other methane offsets from the full gamut of fossil fuels and even agriculture. (SAEGER)

Comment: we all have a duty to the ground we walk on to the air we breath an to the water we all need, this goes for us humans too, it's up to us how well we leave it for the next generations to come, there's no room left on earth for "OFFSETS",, To all we should be gratefull that the water, air, and the ground are still here for us all stop methane offsets and any others that can damage mother earth. Da-nay-to Haiwagai:I (EDWARDS)

Comment: The Mine Methane Capture Protocol is actually a trojan horse designed to deceive the public and those legislators not already in on the scam. Kill it. (WHEELOCK)

Comment: To call this nonsense spurious logic would be an understatement ...the ENTIRE 'carbon credits' program is spurious nonsense, and the PEOPLE are not fooled by it. Appealing to the ethics of a politician is an exercise in wasting breath, so instead I'll appeal to your vanity instead and ask, How do you want to be remembered? .. a champion ... or just another vile piece of flotsam? (BRAY)

Comment: If we don't switch to green energy all the money in the world will not help us as we deal with climate change. (JARSOCRAK)

Comment: The Protocol represents the advent of a trading commodity – methane offsets. Furthermore, the Protocol stands to be a dangerous prototype for the future development of other methane offsets from the full gamut of fossil fuels and even agriculture. (A proposed rice methane capture protocol is also currently under development for future inclusion in AB32.)

NO TO A832!!!!!!!!!!!!!!!!!!! (MARTINEZ)

Comment: Stop mining fossile fuels!!! To continue to use them is Planetary & Social Suicide!!! Thank You for your vital compliance! (DRZARRO)

Comment: This concept is ridiculous. You have an obligation to your people to be true protectors of the humanity by protecting the environment. Get your act together. (STOCK)

Comment: The offset is moot. No allowances will be necessary. The offset will be in population transfers, and the demand for commodity will adjust. (YYEW)

> **Response:** Thank you for the comments. The Cap-and-Trade Regulation and the original four carbon offset protocols were approved by the Board in 2011. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB does note that the limited use of offsets serves as an important cost-containment feature in the Cap-and-Trade Program, which reduces emissions and works in conjunction with other AB 32 measures that shift California's energy consumption toward renewable sources.
>
> A rice cultivation protocol is not included in this rulemaking and any comments related to this protocol would be considered and addressed during the public process associated with the evaluation of that protocol and any potential future rulemaking to add the protocol to the Cap-and-Trade Regulation.

J-1.5. Multiple Comments: I do not believe that Methane burn off is helping the environment and deserves rewards. I request that you stop rewarding burn off of Methane with Offsets. (SIMON)

Comment: Converting methane to carbon dioxide does nothing to reduce the amount of carbon in the atmosphere. Please cut out the proposed Mine Methane Capture Protocol from California's Global Warming Solutions Act AB32. Thank you for your time. (DUBE)

Comment: I'm writing to ask that flaring of methane emissions from coal extraction be excluded as a carbon abatement strategy considered in California's greenhouse gas regulations. (DENHERDER)

Comment: As a father, this sort of lack of thinking scares me. I know that as someone who thinks about the future of my children I am in the minority, but for heaven's sake, lets be real! Burning off methane in no way contributes to our children's chance of survival. Let's try and solve the problem of polluted water, polluted air, and polluted soil, instead of giving more ways for the rich to get richer. We need problem solving, not problem creation. (WOOD)

> **Response:** Thank you for the comments. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB does note that CO_2, a greenhouse gas, is released when methane is destroyed via a flare or other destruction method as allowed for in the MMC protocol. Methane has a much higher global warming potential than carbon dioxide so the CO_2 emissions resulting from the destruction of methane still represent a reduction in the terms of the net climate impact. Nonetheless, the MMC protocol takes into consideration the release of CO_2 from the destruction of methane, regardless of the destruction method or employed, and accounts for the impact of these emissions in the quantification methodologies. It is only the real, net emission reductions that are credited.

J-1.6. Multiple Comments: The Asian Pacific Environmental Network (APEN) is a strong supporter of AB32, but oppose the offsets program being developed by California. We need direct emissions reductions from GHG pollution, not market schemes for polluters to avoid their responsibility to emissions reduction. We work with hundreds of families living next to oil refineries and other big polluters and want to see those emissions reduced to improve the ailing health of our communities and to combat climate change. We see no benefits for offsets. We are also raising this opposition to offsets under the AB32 Environmental Justice Advisory Committee. (APEN 2)

Comment: There is no anticipated substantial net effect on pollution in California by applying foreign (subnational, national, or international) offset credits for greenhouse gas emissions in California. (MARKS)

> **Response:** Thank you for the comments. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, we do note that the MMC protocol does not obviate any existing local or regional air quality regulations or control programs related to the management of criteria or toxic air pollutants in California.

J-1.7. Multiple Comments: Please do not proceed with the proposed Mine Methane Capture Protocol (MMCP) in California's Global Warming Solutions Act AB32. The National Resources Defense Council has said it well:

"Adoption will help keep [Cap and Trade] allowance prices low by adding tens of millions of tons of potential emissions reductions to the carbon market. But there is no need right now for further cost containment. ARB has proposed an additional safeguard to ensure allowance prices stay within a reasonable range and recent forecasts suggest that, if anything, the concern may be in the other direction, as allowances are projected to stay near the floor price for the foreseeable future." (http://switchboard.nrdc.org/blogs/pmiller/coal_mine_methane_offsets_a_ba.html) (MILLER)

Comment: The MMCP's implementation is scheduled to coincide with the participation of the transportation fuels industry in California Cap-and-Trade, which was delayed until 2015; it has been pushed in its development because of a stated need in the fossil fuel industry for more carbon offsets. This is not a viable argument for pushing its implementation. (MARKS)

> **Response:** Thank you for the comments. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB notes the MMC protocol is consistent with the requirements of the Cap-and-Trade Regulation and AB 32 including the objective of achieving cost-effective emission reductions.

J-1.8. Comment: MMCP requires that for offset project to be situated on tribal lands, tribes would have to issue a "waiver of sovereign immunity." This demand is obviously for liability purposes; no such demand of waiver of immunity for liability is demanded of the fossil fuel corporations involved. (MARKS)

> **Response:** Thank you for the comment. Since this comment is outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB notes the provision related to the waiver of immunity is to ensure equitable enforceability of all offset projects, regardless of where they are located. A limited waiver of sovereign immunity by the Tribe helps to ensure the ability of the State to enforce its interest in the proper functioning of the Cap-and-Trade Regulation with respect to project operation within the external borders of Indian lands. ARB believes that the requirement of entering into a limited waiver of sovereign immunity, as well as the requirement that this waiver include a consent to suit, are sufficiently clear to provide the public and Tribes with an understanding of what is required under these provisions of the regulation. Each Tribe that wishes to participate in the Cap-and-Trade Regulation would be required to enter into an individual limited waiver of sovereign immunity with ARB in accordance with the Tribe's Constitution or other organic laws, by-laws and ordinances, and applicable federal laws.

J-1.9. Multiple Comments: Coal is a major contributor to climate change, regardless of other sources of energy. (GLASS)

Comment: Methane escaping from coal extraction is extra emissions that mining operations should have to count as part of their GHG burden. It's unfair to count the flaring of such gas, as a reduction in their impact, especially when it comes from an activity (coal mining) that is central to causing the problem in the first place. (DENHERDER)

Comment: This is absolute craziness you bringing in laws to accommodate the likes of oil and mining and oil industries need for money over the well being of the planet as global warming is the number one thing that will change tip our climate beyond repair. I think that you should start making laws that will protect your citizens not the interests of the corporates people before profits. (SLADE)

Comment: Don't be fooled. Fossil fuels are not sustainable. Please do not even consider giving carbon credits to a company or corporation involved in fossil fuel extraction. There is no such thing as Ethical Oil. Please dont be fooled that there is such thing as ethical coal now too. Think for yourself. Ask a scientist. Oh, I mean a citizen scientist. Ask the people. Listen to the people. We want to go Solar! We want to use bio-fuel for vehicles, machines, etc. Carbon tax is the only way that you can help to get the mining companies and the word environmentally friendly on the same page, not the other way around. Please dont let them fool you. We the people that are awake are not that stupid.

Thank you for your time. You are a very important part of saving the planet...or not. (CMORRISON)

Comment: Mine Methane Capture should be REQUIRED BY LAW, and any violation severely penalized, instead of being optional and rewarded with incentives like offset credits. Methane is such a potent greenhouse gas that in fact the entire mining industry should face stringent regulations and strong DISINCENTIVES from mining for any fossil fuels at all, and for all emissions throughout the entire process. (ZHOU)

Comment: Do not let the coal industry continue to pollute the planet. (DESENZE)

Comment: absolutely disgusting and abhorrent. these coal and oil tycoons will singlehandedly run the environment into the ground, leaving nothing but toxic wastelands to our future generations. i think theyve hoarded enough money to support themselves modestly for several lifetimes. (NES)

Comment: If CO2 ppm were at 360, and we had a couple of decades to deal with our destruction of our possibilities on this planet, I would applaud these efforts. Given where we are now - where even the careful IPCC is allowing itself to raise an anguished alarm - these proposed rules are sad. And criminal. We cannot afford to continue using coal.

We cannot afford to release one molecule of methane that we can stop. Otherwise, the permafrost giant up north (holding about 5 times as much carbon as humanity has released since 1750) will rouse itself with a roar. (BUCKLEY)

Comment: Mine Methane Capture Protocol (MMCP) Comment Summary

- The MMCP stands to be create a negative prototype for the future development of other carbon offsets because of its encouragement of unsustainable industry.
- The MMCP's anticipated "capture and destruction" technologies (both euphemisms) are undefined and unlimited. Mentioned are drilling bore holes and new wells, oxidation, flaring (burning), refineries for conversions to compressed or liquefied natural gas, electric or thermal generating plants, gas pipeline systems, roads, and other infrastructure.
- In fact, the carbon offset protocol trading mechanisms are a lucrative avenue for corporations to buy their way out of liability for their industry's pollution. (MARKS)

Comment: NO CONSENT TO CONTINUED SUPPORT OR EXPANSION FOR FOSSIL FUELS. WE WANT WIND AND SOLAR POWER EMPOWERED AT THE INDIVIDUAL LEVEL TO SUPPORT THE GRID WITH DISTRIBUTED GENERATION WITH A FAIR PRICE PAID TO CONSUMER WHO ALSO ACT AS SUPPLIERS. California and its people have endured enough damage from the fossil-fuel paradigm. We as agent and principal withdraw our consent (SOPHINA).

> **Response:** Thank you for the comments. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB notes that the MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. No action that ARB takes in execution of California's Cap-and-Trade Program precludes federal action on regulation of greenhouse gas emissions.

Public Process and Protocol Development

J-1.10. Multiple Comments: We commend the excellent efforts of ARB staff and the quality work that was involved in bringing this Protocol forward. We commend ARB for their work to bring this Protocol successfully forward. This will be the first offset protocol written entirely by ARB through the public protocol development process. CVP encourages the ARB Board members to approve and render this protocol effective as soon as possible. (EVANS)

Comment: ESI strongly supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects. This will be the first protocol written entirely by ARB through the public protocol development process. ESI encourages officials to approve and make effective the protocol as soon as possible. (ESI)

Comment: Holy Cross Energy supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects. This will be the first protocol written entirely by ARB through the public protocol development process. (HCE 2)

Comment: The Conservation Center encourages the California Air Resources Board to approve and make effective the protocol as soon as possible. (WSCC)

Comment: Blue Source strongly supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects, and commends ARB for its hard work in developing a protocol that will economically enable the destruction of waste mine methane previously vented to the atmosphere. Blue Source encourages ARB to approve and make effective the protocol as soon as possible. (BLUESOURCE 2)

Comment. WREA Inc strongly supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects. This will be the first protocol written entirely by ARB through the public protocol development process. WREA Inc encourages officials to approve and make effective the protocol as soon as possible. (WREA)

Comment: Encore BioRenewables strongly supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects. This will be the first protocol written entirely by ARB through the public protocol development process. Encore BioRenewables encourages officials to approve and make effective the protocol as soon as possible. (ENCORE)

Comment: Anticipated to be the first protocol written entirely by ARB through the public protocol development process, ClimeCo encourages officials to approve and make effective the compliance offset protocol for mine methane capture (MMC) projects as soon as possible (CLIMECO).

Comment: Vessels strongly supports the proposed California Air Resources Board (ARB) compliance offset protocol for mine methane capture (MMC) projects. This will be the first protocol written entirely by ARB through the public protocol development process. Vessels encourages the Board to approve the Mine Methane Capture Protocol and make effective date of the protocol as soon as possible (VESSELS 3).

Comment: I commend the ARB staff for producing a well-designed and effective MMC protocol. The quality and relevance of the work indicates that the staff successfully learned critical intricacies of mining operations and understands the economics of the industry to ensure incentives created by the Protocol are fairly applied and distributed. (ECC)

Comment: We understand the actual implementation of the Protocol will take place only after its approval by the Office of Administrative Law (OAL) and the training of accredited verifiers. While we understand and respect ARB's administrative constraints, we do wish to underline the importance of not delaying the implementation schedule in order to ensure MMC projects will start delivering offsets as soon as possible. (BIOTHERMICA 2)

Comment: Please approve the Mine Methane Capture Protocol and the make effective date of the protocol as soon as possible. (TOOLE ONEIL 2)

Comment: PG&E also appreciates the incorporation of stakeholder feedback into the offset-related sections of the amended regulation and the latest draft of the Mine Methane Capture (MMC) protocol. (PGE 4)

Comment: IETA encourages officials to approve and make effective the protocol as soon as possible. (IETA)

Comment: I'm here to express the Reserve's support for the Board's adoption of the Reg amendments before it today, including the Mine Methane Capture Protocol. We're proud that the mine methane protocol is based in large part on work the Reserve has undertaken which is embodied in the Mine Methane Capture Protocol. We appreciate staff's hard work and willingness to consider comments we've submitted on the draft, and we look forward to continued collaboration on future protocols we hope and ongoing OPR work. (CAR 3)

Comment: Thank you, Chairman Nichols and the Board for allowing me to testify in favor of the amendment, specifically the Mine Methane Capture Protocol. I want to thank the staff for allowing me to participate in the stakeholders process. It was very thorough and rewarding. (VESSELS 4)

Comment: I wanted to promote the adoption of the mine methane protocol. I think it's one of the unique things right now is that this is one of the first protocols ARB staff have developed themselves. I think the process has gone exceptionally well. I want to commend the staff on that protocol. (CE2CAPITAL 5)

Response: Thank you for the support.

J-1.11. Multiple Comments: We know that the State of California asked a mining executive to write the Mine Methane Capture Protocol (THERULES)

Comment: Why are you allowing the mining companies to write the regulations. Don't you work for the people not the coal industry. (JARSOCRAK)

Comment. Furthermore, the fact that a mining executive drafted the protocol smacks of a conflict of interest and does not reflect well on CARB. (AAO)

Comment: Representatives of the mining and fossil fuel industries have contributed heavily to the protocol’s drafting, dictating its terms. Carbon traders have also participated in its development. (MARTINEZ, SAEGER)

Comment: Representatives of the mining and fossil fuel industries have contributed heavily to its development and have dictated its terms. Participants in the carbon trade industry have also participated in its development; the MMCP represents a valuable trading commodity as written. (MARKS)

> **Response:** Contrary to these comments, the proposed MMC protocol was not written by mining companies nor mining executives. Staff undertook an extensive public process, consistent with the requirements of the Administrative Procedure Act, in the development of the MMC protocol. As evidenced by this process, the development of a new compliance offset protocol takes considerable time as staff seeks to engage with a diverse set of stakeholders and put forward the best possible protocol that meets the rigorous standards of the Cap-and-Trade Regulation. As in the past, staff started the protocol development process by evaluating existing offset protocols and evaluating their best design features through a public process to develop ARB’s version.

Perceived Perverse Incentive to Flare Methane

J-1.12. Multiple Comments: There is no reason to flare methane! It can be captured and converted for use! You plan to PAY to WASTE a resource?! Are you INSANE? (MARCINIAK)

Comment: I can think of no more counterproductive and hypocritical regulatory measure than to allow offsets for flaring methane. Methane capture and use for fuel in a productive manner is what California should be requiring - NOT flaring. Please know that you have full support from the American people for strict regulation. The planet and we, its inhabitants, cannot afford to ignore any unproductive release of carbon to the atmosphere. (MOORE)

Comment: Do not capture and burn off methane gas. It is wasteful and creates global warming. It is one thing to use a resource, another to waste it. (BARNES)

Comment: We continue to believe that there are additional opportunities to strengthen the Protocol. Our first three recommendations, listed below, involve excluding certain sub-sets of projects from participating in the Protocol to avoid specific adverse effects from the incentives the Protocol would otherwise create. We believe that the exclusion of these sub-sets of project types would not in any way diminish the policy-effectiveness of the Protocol as a compliance instrument under the cap-and-trade program. These three recommendations focus on drainage methane from active underground mines. Our recommendations are:

(3) Furthermore, incentives for mines to flare methane that would otherwise have been injected into a pipeline is a second reason to specifically eliminate eligibility of drainage methane flaring at new underground mines.

Allowing offset credits from the flaring of drainage methane is of particular concern at new mines. At recent natural gas and offset credit prices a mine operator could earn more income from selling offset credits than from selling natural gas. While the Protocol largely prevents mines that already inject drainage methane into a pipeline from switching to flaring to sell offset credits, this protection does not extend to new mines. A mine operator could list a flaring project under the Protocol even if they would have chosen to inject that methane into a pipeline absent the incentive created by the Protocol.

At recent natural gas and carbon allowance prices, a mine operator would receive greater income from offsets for flaring methane from drainage wells than from selling that methane into a natural gas pipeline. This is true even when the greater costs of implementing a pipeline injection system compared with a flaring system are ignored. The Board has largely avoided incentivizing mines that already pipeline inject to switch to flaring by making drainage methane ineligible for crediting if a well has captured methane for pipeline injection within the previous year. But the incentive to flare instead of pipeline inject is not avoided for new mines. Operators of new underground gassy mines that may have otherwise chosen to sell their methane into a pipeline in the absence of the Protocol can choose to flare this methane to earn carbon credits. This would not only result in substantial non-additional crediting (methane destruction would be credited that would have happened through pipeline injection without the offset protocol); it would also have the added impact of flaring methane that would otherwise have been put to productive use. While we recognize that new mine wells are not expected to be a major source of projects under the Protocol, given current market conditions, this specific exclusion would avoid non-additional crediting and the broader effects of causing methane to be flared that otherwise would have been used productively. We emphasize that the Protocol should be robust to changes in global fossil fuel markets as they have a long history of volatility. (See Figure 1 from our comments from 1 July 2013 for a more detailed discussion of this concern.)
(STANFORD 5)

Comment: So we appreciate the careful considerations that ARB staff has made in the design of the Mine Methane Capture Protocol, but we believe that two possible effects of the protocol still need to be considered and addressed by the Board.
First, we ask the Board exclude projects which flare drainage methane from active underground mines, at least until sufficient analysis has been done of the issues that we raised. My colleague, Emily Grubert, will discuss the second issue in her comments related to the conflict between the protocol and federal legislation.
Underlying both sets of comments is this: Placing a price on carbon, whether through cap and trade or carbon tax, is economically sound. It internalizes an externality, but carbon offsets function differently. They incentivize reductions. When an offsets protocol chooses to credit certain activities and not others, it risks creating the distortionary

incentives that could have outcomes contrary to the goals of AB 32. Our underlining concern is that the full range of incentives created by the protocol must be carefully and conservatively considered when protocols are developed.

So regarding flaring from drainage wells at active underground mines, as context, only ten active underground mines in the country are able to install drainage wells for flaring projects because only ten currently vent methane from drainage wells rather than capture the methane for injection into a pipeline. These are among the gassiest mines in the country with very large releases of methane.

Second, we believe ARB has opportunity to allow offset revenues to incentivize the capture of drainage methane for use, such as electricity generation, rather than incentivizing the waste of that natural resource through flaring. Since flaring technology is less expensive to implement than systems that use methane, we're concerned that the protocol might result in the flaring of methane that would be put to use if flaring were not included in the protocol.

We believe that these potential effects of the protocol need to be avoided and monitored. A substantial portion of these effects can be avoided by immediately excluding the flaring of drainage methane at active underground mines from crediting the protocol. (STANFORD 6)

> **Response:** Thank you for the comments. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB notes that staff considered the impact of incentives created by the MMC protocol and determined that the MMC protocol is unlikely to incentivize the flaring of methane that would otherwise be put to productive use. During the technical working group meetings, staff and stakeholders discussed the application of eligibility thresholds for various destruction activities. It became evident to staff, given the constraint of limited data and the variability of methane content and flow rates at mines, that any attempt to develop standardized eligibility thresholds would result in arbitrary restrictions and problematic project implementation.
>
> Commenters suggest that if thresholds are not applied, that new mines and those undergoing major modifications should be excluded outright from the MMC protocol based on the assumption that such mines would inject into pipeline without the existence of the MMC protocol. Staff does not agree with those assumptions for the same reasons that establishing eligibility thresholds is not practical. Staff cannot predict if a mine would or would not send gas to a natural gas pipeline and as such the MMC protocol only assesses past actions. The same commenters also suggested that flaring should not be an eligible destruction method at any underground mine. Staff again disagrees with this proposal as it would unnecessarily limit the greenhouse gas reductions that can be achieved under the protocol.

Staff also disagrees with the comment suggesting that the MMC protocol incentivizes “unproductive” use via flaring over “productive” use such as pipeline injection. The assertion is based on the belief that the flaring of captured methane as allowed for under the MMC protocol would be a more profitable venture than selling the mine methane via injection into a natural gas pipeline. Staff conducted an analysis as part of the 15-day changes comparing the revenues generated from pipeline injection and offset sales and found that, under plausible pricing scenarios, the difference between the revenue streams to be slight and variable.

Staff would also prefer to see captured mine methane used productively rather than flared. In fact, multiple productive end-uses other than pipeline injection are eligible destruction methods under the MMC protocol. Nonetheless, the primary goal of the MMC protocol is to incentivize the destruction of mine methane that would otherwise flow unabated into the atmosphere. Depending upon the quality or quantity of the gas or the terrain where the mine is situated, flaring is the only feasible destruction option and flaring is certainly preferable to methane being freely emitted. As previously mentioned, developing eligibility thresholds for flaring proved impractical.

It should be noted that, as part of their 15-day comments, Stanford students resubmitted some of their 45-day comments. As these written comments are duplicative, responses to comments contained within both comments can be found in response to 45-day comment J-1.8 in Chapter IV of this Final Statement of Reasons document.

No Perverse Incentive to Flare Methane

J-1.13. Multiple Comments: Project developers recognize the value of energy in mine methane and endeavor to utilize this resource where possible. Unfortunately, the extreme terrain and remote and often isolated locations of many mines prohibit the utilization of this energy. Recognizing flares as qualifying destruction devices is essential to maximize GHG emission reductions driven by this protocol as the alternative would be to vent this gas. (ECC)

Comment: People keep saying why must you flare, which brings me to my third and final point. If we flare, it's because it's the only viable option. In most cases, we don't -- if we didn't have to flare, we wouldn't. Most projects would likely be located far from existing gas pipelines or points where we could connect to the local grid where we would put the methane gas to beneficial use and generate additional revenue for our projects and diversify our risk. (GREEN 2)

Response: Thank you for the support. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB staff agrees with the commenters about the importance of including in the MMC protocol the option to flare methane that would otherwise be vented into the atmosphere.

Perceived Conflicts with Federal Regulations

J-1.14. Multiple Comments: Please do not proceed with the proposed Mine Methane Capture Protocol (MMCP) in California's Global Warming Solutions Act AB32. The National Resources Defense Council has said it well:
"The environmental law clinic at Stanford Law School has pointed out potential conflicts with future federal regulation under the Clean Air Act. In particular, the opportunity for coal mines to be paid to reduce emissions may make it more difficult to adopt regulations that require them to reduce emissions…"
(http://switchboard.nrdc.org/blogs/pmiller/coal_mine_methane_offsets_a_ba.html)
(MILLER)

Comment: I'm speaking in opposition to the adoption of the Mine Methane Capture Protocol in its current form, because of two situations where the protocol could have an outsized impact on future federal regulation if it precedes action by the Bureau of Land Management and under the Clean Air Act.

First, concerning the BLM, I'd like to alert the Board to yesterday's press release announcing an advanced proposed rulemaking on mine methane. In the BLM's words in that press release and the ANPR, "The BLM is considering establishing a system for the capture, use, sale, or destruction of waste mine methane liberated from federally leased lands by active underground mines." This is significant because some of the country's gaseous underground mines are located on federally leased lands. One area where BLM is actually requesting comments is whether it should control methane through mandates versus incentives. We believe as an existing structures that offers incentives for methane control, if adopted, the protocol has high potential to influence the design in favor of incentives rather than mandates at this time.

Secondly, concerning the Clean Air Act, which my colleague, Barbara Haya, alluded to earlier, we are concerned if the protocol allows new mines and major mine expansions to generate offsets, it could impact Clean Air Act methane regulation in the future. As detailed in written comments, we recommend excluding new mines and major mine expansion gassy enough to trigger Clean Air Act permitting from the protocol.
Clean Air Act rulings on pollutants rely heavily on precedents established by rulings at similar sites. And to date, no precedent has been established for methane control from new mines and major expansions, which are relatively unusual but can be very high emitters. It's clear methane capture and/or destruction is the best available control technology in most, if not all, cases based often EPA cost forecasts and earlier rulings at landfills, which are quite similar to mines from a methane control perspective.
Our concern is that if California offset credits are available, states might not follow clear EPA guidance and might choose to preserve offset revenues for mines rather than require methane control under the Clean Air Act. Thus, the inclusion of new mines in major expansions gassy enough to require Clean Air Act permits under this protocol

could change the course of the precedent from requiring methane control to not requiring methane control.

We recommend excluding these permit requiring mines from the protocol for two years to allow opportunity for precedents to be set. These two cases illustrate our concern that the offset protocol has a high potential to weaken developing federal regulations on mine methane. And specifically the value of an offset will impose an additional financial barrier to federal regulation as regulators will have to consider the cost of removing the opportunity for offset revenue. (STANFORD 7)

> **Response:** Thank you for the comments. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB notes that staff considered the concerns raised in these comments and others similar to them and provided a detailed response in Attachment A of this document: Response to Comments on the Environmental Assessment Prepared for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms.

No Conflicts with Federal Regulations

J-1.15. Multiple Comments: My name is Michael Cote, President of Ruby Canyon Engineering. We've been working as a subcontractor to U.S. EPA's Coalbed Methane Outreach Program for the past 16 years. And the Coalbed Methane Outreach Program is a voluntary program under the Climate Change Division to encourage coal mines to economically find ways to methane mitigation. And I can say unequivocally these projects that are included in the mine methane protocol do need incentives in order to see them deployed.

I'd also like to comment on federal regulation that the Clean Air Act does not -- regulation does not apply to fugitive methane from surface mines or to abandoned underground coal mines. In two of the three section of the Mine Methane Protocol do not come under any kind of federal regulation or will come under any federal regulation. That leaves underground coal mines where there is a vehicle in place called the tailoring rule, which is expected to address the reviews of ways of mitigating methane at coal mines. The process will involve PSD reviews and BACT determination. And if you look at the lion's share of coal mine methane is coming from the ventilation fans, these thermal oxidation projects, there's only seven or eight of these that have been deployed worldwide over the past decade. We consider that the technology is still -- while not in its infancy, is not ready for prime time to be considered for BACT. And only through the incentives of carbon financing and other types of incentives will we see these rolled out in a larger scale and maybe eventually become BACT decades away.

And then finally, I'd like to comment on the BLM's advanced notice of public rulemaking that recent eligibility criteria just came out. We were in discussions with the BLM earlier this year and really what we believe they're looking for are voluntary cost-effective ways of addressing this issue. We don't believe there will be mandates.

And also, just so you know, that only ten percent of the coal mine methane emissions in the U.S. come from public lands. So even if they do mandate something, it will represent a very small piece of the solution. So I encourage the Board to adopt the mine methane protocol today. (RCE 4)

Comment: And second is just the federal and national action. I very much think that your actions today on this protocol can show that there needs to be some type of national regulations to reduce emissions from mines. I think this is a great signal that something needs to be done and a great incentive in order to push that forward. I urge your adoption. (CE2CAPITAL 5)

> **Response:** Thank you for the support. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB staff agrees with the commenters that there is no conflict between the MMC protocol and the Clean Air Act (CAA). Further, no action that ARB takes in execution of California's Cap-and-Trade Program precludes federal action on regulation of greenhouse gas emissions.

Legal Requirement Test

J-1.16. Comment: Second, we support the clarification that the Legal Requirement Test for additionality must be met throughout the life of the project, and not just at the time of project listing (section 3.4.1(a)). This change avoids another potential source of non-additional credits. Again, we believe that this change will substantially strengthen the final version of the Protocol. (STANFORD 5)

> **Response:** The commenter misinterprets the modification to section 3.4.1 of the MMC protocol. Through the 15-day amendments, ARB staff removed previous language specifying that the Legal Requirement Test must be applied at the time of offset project commencement to avoid redundancy with the Regulation. The protocol now cites sections 95973(a)(2)(A) and 95975(n) which require that the Legal Requirement Test be applied at the time of offset project commencement and again at the time of crediting period renewal. The legal requirements test is applied to potential MMC projects in the same fashion as other ARB offset project types. Like other non-sequestration compliance offset protocols, the crediting period for the proposed MMC protocol is ten years. Staff believes that this is sufficient time needed to make an investment attractive for most MMC projects.
>
> The concept of a crediting period is found in several regulatory and voluntary offset programs around the world. The crediting period refers to the period that an offset project is allowed to be issued compliance offset credits. Offset project developers need a guarantee of return on their investment. The most efficient way to do this is to establish a crediting period in which the emission reductions or removals from their projects will be eligible for offset credits. Without certainty

about a project's life span, there may be too much risk for a project to attract investors. Therefore, staff understands there must be some guarantee that the emissions reductions achieved according to a protocol will be eligible to generate offset credits for a given period. However, some types of offset projects could no longer be valid for generating offset credits in the future. ARB's offset program is designed to balance between guaranteeing investment certainty and allowing ARB to update methods and quantification, as well as to reevaluate and readjust baseline and additionality requirements in protocols in the future. Offset projects may only qualify for renewed crediting periods if they continue to meet the requirements for additionality.

It should be noted that, as part of their 15-day comments, Stanford students resubmitted some of their 45-day comments. As these written comments are duplicative, responses to comments contained within both comments can be found in response to 45-day comment J-1.11 in Chapter IV of this Final Statement of Reasons document.

Additionality of Surface Mine Projects

J-1.17. Comment: The current draft of the Protocol notes that "a destruction device that is operational at the mine prior to offset project commencement is considered a non-qualifying destruction device even if retrofitted thereafter," (Section 1.2(a)(32) under the definition of "Non-Qualifying Destruction Device"), an addition that we appreciate and agree with as critical for ensuring additionality of offsets from surface mine methane. We understand this to mean that a coalbed methane (CBM) well with operable pipeline injection infrastructure would not be eligible for crediting under the Protocol. Such a restriction is important because it is common for methane from CBM wells that come within the plan boundaries of an expanding surface mine to continue to capture methane for pipeline injection even after well ownership shifts from the gas well owner to the coal mine owner if the wells remain economic. Ruby Canyon Engineering estimates that approximately 15% of CBM wells that were drilled in areas that are now within the boundaries of surface mine Conflict Administration Zones (CAZ) remained open in 2007 (vs 59% of wells drilled in areas that are outside a CAZ).[246] This is a significant proportion, particularly given that the wells that remain active are likely to be the most economic, which generally corresponds to those with the highest methane production.

We suggest that the Board amend the language of the Protocol to clarify this requirement. In particular, Section 3.4.2(b)(3)(A) should be revised to read (additions underlined):

[246] Ruby Canton Engineering, Inc. 2013. Abandoned Coal Mine Methane Offsets Protocol: Background Information on Performance Standard and Additionality

“Destruction of extracted mine methane via any qualifying end-use management option automatically satisfies the performance standard evaluation because it is not common practice nor considered business as usual.”

Additionally, Section 2.3(b) should be be further amended to read:
“In order to be considered a qualifying device for the purpose of this protocol, a methane destruction device for an active surface mine methane drainage activity must not have been operational at the mine, whether before or after acquisition by the mine, prior to offset project commencement.”

Such clarification to the surface mine methane eligibility provision would parallel the clarification that the Board has already made to the eligibility of methane capture at abandoned mines – pipeline injection infrastructure implemented at active underground mines, which are considered non-qualifying under the Protocol, remain non-qualifying after mine status has changed. We urge the Board to make this important revision to clarify that pipeline injection infrastructure built to capture CBM is considered a non-qualifying device. (STANFORD 5)

> **Response:** The definition of a non-qualifying destruction device was modified through 15-day revisions to add language stating that “a destruction device that is operational at the mine prior to offset project commencement is considered a non-qualifying destruction device even if retrofitted thereafter.” This should be interpreted to mean that if pipeline injection occurred prior to project commencement that the pipeline is deemed to be a non-qualifying device. This addition does not have bearing on the eligibility of any methane source such as a coal bed methane well that would otherwise be shut-in and abandoned as a result of encroaching mining. The eligibility of this methane source was unchanged in the protocol and therefore the comments are outside of the scope of the 15-day changes to the MMC protocol and no response is necessary. Nevertheless, ARB notes that if a well was connected to a non-qualifying device at the time of offset project commencement or within one year prior to offset project commencement that methane from that well is not eligible for destruction under the protocol. Staff does not believe that the suggested additions to sections 3.4.2(b)(3)(A) and 2.3(b) are necessary for the MMC protocol to be implemented as intended.

Additionality of Abandoned Mines

J-1.18. Multiple Comments: Please do not proceed with the proposed Mine Methane Capture Protocol (MMCP) in California’s Global Warming Solutions Act AB32. The National Resources Defense Council has said it well:

"The environmental law clinic at Stanford Law School has pointed out problems with the analysis of how much methane will be captured from abandoned mines without the protocol…”

(http://switchboard.nrdc.org/blogs/pmiller/coal_mine_methane_offsets_a_ba.html) (MILLER)

Comment: We thank the Board for clarifying that it is considered common practice for mines that captured methane for pipeline injection when they were active to continue capturing methane once abandoned, meaning that such continued methane capture at abandoned mines is non- additional and, therefore, ineligible for crediting (Section 3.4.2(b)(4)(B)).

We sincerely appreciate two clarifications included in the informal draft that we believe will substantially strengthen the additionality of projects eligible for crediting under the MMC protocol. First, we thank you for clarifying in section 2.4(b) that abandoned mines that injected methane into a pipeline while active are not eligible to generate credits from pipeline injection once abandoned. This practice is very common – we understand that every mine abandoned since 1996 that had injected methane into a pipeline when active has continued to do so once abandoned. This restriction thus avoids the potential generation of a large quantity of non-additional credits from the abandoned mine portion of the Protocol (reductions that would not be caused by the Protocol and would have happened anyway), while maintaining eligibility for truly additional projects at abandoned mines. We believe this clarification will substantially strengthen the final Protocol.

The Board should clarify in its additionality assessment of mine methane capture at abandoned mines (section 3.4.2(b)(4)) that methane capture by pipeline injection systems installed when mines were active is either common practice or is excluded from the evaluation in this section.

We recommend that the language in section 3.4.2(b)(4) be clarified in the following way so that it more clearly reflects the additionality of methane capture at abandoned mines. 3.4.2(b)

(4) Abandoned Mine Methane Recovery Activities

- (A) Destruction of extracted mine methane via any end-use management option other than injection into a natural gas pipeline for off-site consumption with a pipeline injection system installed when the mine was active automatically meets the performance standard evaluation because it is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this protocol.
- (B) Pipeline injection of mine methane at abandoned mines that injected drainage methane into a natural gas pipeline for off-site consumption when the mine was active is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

This change reflects that it is common practice for pipeline injection at active mines to continue after mine closure. This clarification does not affect project eligibility under the Protocol. Section 2.4(b) already states that pipeline injection systems installed by active underground mines cannot be considered eligible offset projects after mines have been abandoned. Still, we recommend that section 3.4.2(b)(4) be amended to reflect that the capture of abandoned mine methane by pipeline injection systems installed when mines were active is common practice. Alternatively, ARB could make the same correction by stating explicitly in that section that this methane capture is excluded from the evaluation of abandoned mine methane.

The arguments we make below (1) support the need for this clarification, (2) support the exclusion of pipeline injection at abandoned mines by mines that captured methane for pipeline injection when they were active as per section 2.4(b), (3) provide supporting evidence for the additionality of the abandoned mine portion of the Protocol with this exclusion, and (4) demonstrate the steps we recommend the Board use to conduct a full additionality assessment of any project type being considered for offset crediting under a new or revised protocol.

A simple common practice assessment

The Board's common practice assessment of MMC at active underground mines found that a subset of possible MMC projects – projects injecting methane into a pipeline – is common practice. These projects were excluded from the draft protocol. Similarly, for abandoned mines, it is very common practice for mines that captured drainage methane for pipeline injection when active to continue pipeline injection once abandoned. Every mine that pipeline injected when it was active that was closed since 1996 continued to pipeline inject when it was abandoned.[247]

This assessment holds, even though three of these mines participated in a voluntary offset program making their additionality uncertain.[248] The majority of these mines – five out of eight – did not participate in a voluntary offset program and so are clearly business-as-usual (did not require offsets to be built). Further, all eight abandoned mines have characteristics that point to the cost effectiveness of methane capture without the need for offset credits, including the three that participated in the voluntary offset market. They each have large releases of methane, and already had pipeline injection infrastructure in place when the mine was abandoned.

A simple common practice assessment as described herein, similar to that used by the Board to assess the additionality of active underground mines, should lead to the conclusion that this one subset of abandoned mine methane capture is common practice. This should be clarified in section 3.4.2(b)(4).

[247] We listed all active underground mines that captured methane in 1996 and 2006 from two reports: Environmental Protection Agency. 1997. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines*, and Environmental Protection Agency. 2009. *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006.* EPA 430-K-04-003. We examined whether each of these mines is currently active or closed using three methods: (1) the listing of abandoned mines capturing methane in a personal letter from Ronald C. Collings, V. P., Ruby Canyon Engineering, Inc. RE: California Air Resources Board: Proposed Compliance Offset Protocol Mine Methane Capture Projects, dated August 19, 2013. to Jessica Bede, California Air Resources Board. Dated October 22, 2013, (2) Mines dataset from the Mine Safety and Health Administration (MSHA) listing all mines in the country by type and status, and (3) internet searches for articles on each of the mines.

[248] Aberdeen mine is listed under the Verified Carbon Standard, and Blue Creek No 3 and No 5 mines are listed under the Chicago Climate Exchange.

A full additionality assessment

The importance of excluding pipeline injection systems installed when mines were active from crediting under the Protocol becomes clearer and even more compelling with a focus on credits rather than on projects. Generally, we recommend that the Board conduct the following additionality test on any project type being considered for offset crediting. Using this test, any project type would be considered to meet AB 32's additionality requirement if, focusing just on that project type:

1. the expected effects of the Protocol on new project development substantially exceeds the crediting of activities that would have be built on their own, and
2. conservative methods of estimating emissions reductions is estimated to under-credit emissions reductions by at least the amount of over-crediting expected to result from non-additional projects participating in the Protocol.

Since such an assessment is based on uncertain predictions of the future, we do not recommend a single cut-off value as a passing mark for this test. Instead, this is a reasonableness test. The purpose is to assess if it is reasonable to claim that the inclusion of a certain project type under a Protocol is not likely to credit more reductions than actually enabled, by quantitative assessment of a conservative business-as-usual scenario. We apply this test to abandoned mine methane capture.

Over the last ten years, three gassy underground mines that captured methane from drainage wells were abandoned. These abandoned mines currently capture methane approximating 2.2 million tonnes of CO2-equivalent per year (MTCO2e/y).[249] A similar magnitude of emissions were released by mines abandoned in the previous decade. From 1994 to 2003, five mines were abandoned that continued pipeline injection with systems installed when the mines were active. While we do not have emissions data from these mines, they are in similar coal seams to the mines abandoned in the last ten years, and so can be expected to have captured similar amounts of methane in the first ten years after abandonment. Therefore, this magnitude of business-as-usual methane capture seems like an amount of methane that could reasonably be captured without the help of offset credits from mines with drainage systems that will be abandoned over the next ten years. Based on data from the past two decades, we estimate that over the next ten years around 2.2 MTCO2e/y of non-additional credits could reasonably be generated by the Protocol if mines that captured methane for pipeline injection when they were active are allowed to generate credits from those systems once the mines are abandoned.

Ruby Canyon Engineering estimates that the total potential methane capture from mines have already been abandoned but are not already capturing methane is

[249] personal letter from Ronald C. Collings, V. P., Ruby Canyon Engineering, Inc. RE: California Air Resources Board: Proposed Compliance Offset Protocol Mine Methane Capture Projects, dated August 19, 2013. to Jessica Bede, California Air Resources Board. Dated October 22, 2013

approximately 2.3 MTCO2e/y.[250] This means that in the best case, if *all* abandoned mines with the potential to capture methane with the help of California's offsets program were to install methane capture devices over the next ten years, around half of all methane captured from new projects would still be non-additional.

It can reasonably be expected that only some fraction of the maximum potential methane capture from existing abandoned mines will be built. It can therefore be expected that without the exclusion in 2.4(b), the quantity of non-additional credits from pipeline injection systems installed by active mines would overwhelm methane captured by truly additional development at abandoned mines. This discussion strongly supports the exclusion of continued pipeline injection after mine closure from crediting under the Protocol as specified in section 2.4(b).

With the exclusion in section 2.4(b), the additionality of the abandoned mine section of the Protocol is reasonably solid. We now examine the common practice of new methane capture systems at abandoned mines (i.e. those that continue to be eligible under the current draft of the Protocol). Over the last ten years, seven new methane capture systems were built at fifteen abandoned mines.[251] These projects captured a total of 0.15 MTCO2e/y of methane. Of this, 0.03 to 0.15 MTCO2e/y would have been built without the help of an offset program. 0.03 MTCO2e/y was captured without voluntary offset credits. It is unclear how much of the methane captured under a voluntary offset program is truly additional (would not have been built without the offset program). The two voluntary offsets programs with MMC projects at abandoned mines – Verified Carbon Standard (VCS) and the Chicago Climate Exchange (CCX) – use a project-by-project approach to additionality testing, which has been proven to be inaccurate at testing additionality.[252] The additionality of one of the projects listed under a voluntary offset program is questionable.[253] Over the last ten years, 0.03 to 0.15 MTCO2e/y of methane was captured by new systems installed at abandoned mines that were possibly viable on their own without carbon credits. We are unaware of reasons why new methane capture installations at existing abandoned mines would increase substantially over the next decade. Continued rates of non-additional methane capture at abandoned mines - 0.03 to 0.15 MTCO2e/y – is relatively small compared to the 2.3 MTCO2e/y potential for methane capture with the help off offsets revenues estimated by Ruby Canyon Engineering.

The magnitude of this non-additional crediting (0.03 to 0.15 MTCO2e/y) could easily be compensated for by the amount that the Protocol underestimates reductions from truly additional projects expected to be developed using the Protocol. The abandoned mine portion of the Protocol applies a 20% uncertainty deduction for baseline emissions. That

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[250] Ruby Canton Engineering, Inc. 2013. Abandoned Coal Mine Methane Offsets Protocol: Background Information on Performance Standard and Additionality

[251] personal letter from Ronald C. Collings, V. P., Ruby Canyon Engineering, Inc. RE: California Air Resources Board: Proposed Compliance Offset Protocol Mine Methane Capture Projects, dated August 19, 2013. to Jessica Bede, California Air Resources Board. Dated October 22, 2013

[252] Barbara Haya. 2009. *Measuring emissions against an alternative future: fundamental flaws in the Kyoto Protocol's Clean Development Mechanism.* Energy and Resources Group Working Paper, University of California, Berkeley

[253] See description of Grayson Hill Farms abandoned mine methane capture project in Baker, T. & R. E. Nelson (2005) Creating Something from Nothing: Resource Construction through Entrepreneurial Bricolage. *Administrative Science Quarterly,* 50.

is, actual crediting is 20% lower than best estimates of these reductions. If the Protocol were to effectively enable 0.75 MTCO2e/y of additional methane capture over the next ten years (around one third of the total potential), the underestimation of reductions from these projects due to the 20% discount factor would compensate for 0.15 MTCO2e/y of non-additional crediting. This is assuming that similar quantities of non-additional methane capture occur in the next ten years as the last ten years. Given that some of this methane will be captured for use, displacing other emissions, the underestimation of emissions reductions from truly additional projects will be even greater.

Over time, the Board should monitor the MMC offset projects at abandoned mines. If there is no clear indication of increased abandoned mine methane capture due to the Protocol, in terms of scale or characteristics of the projects, with reductions sufficient to compensate for the risk of non-additional crediting estimated here, the Board should consider amending the Protocol to further restrict potentially non-additional projects from crediting.(STANFORD 5)

Response: The comment misinterprets 15-day modifications to protocol section 2.4(b). Language added to section 2.4(b) does not exclude continued pipeline injection after mine closure from crediting under the protocol. The earlier language of this section, specific to abandoned mines, deemed any destruction device that was operational prior to project commencement a non-qualifying device for the purpose of the protocol. The language added to section 2.4(b) made an exception for abandoned underground mine methane recovery activities at mines that previously engaged in active underground drainage activities and the destruction device was considered a qualifying device for those activities. For example, if an active underground mine began generating electricity from mine methane under the MMC protocol that mine may continue to use the same equipment to generate electricity and earn emission reduction credits after abandonment.

ARB staff modified section 3.4.2(b)(4) of the MMC protocol through 15-day amendments using language similar to the text suggested by a commenter. The portion of the comment attempting to describe ARB's assessment of common practice for abandoned mines is incorrect. The modification serves to exclude pipeline injection as an eligible end-use management option at abandoned underground mines that injected mine methane into a natural gas pipeline while active, an activity already deemed to be common practice and therefore ineligible for the purpose of this protocol. The rationale for evaluating a subset of active underground mines was included in the Initial Statement of Reasons which states that common practice for active underground mine methane drainage activities was assessed by examining the smaller population of active underground mines with existing methane drainage systems because the installation of methane drainage systems is considered a response to regulation requiring that methane levels be kept below one percent in mine working places and intake air courses.[254] There is no such regulatory requirement for abandoned mines and thus examining subsets of abandoned mines is not warranted except for the fact that the subset of active underground mines would eventually become abandoned underground mines, and staff believed that it was inconsistent to crediting emission reductions at an abandoned underground mine for an action considered common practice for an active underground mine.

The assessment of additionality of abandoned underground mine methane recovery activities was done in accordance with the published ARB process for the review and approval of compliance offset protocols.[255] Staff evaluated the deployment of mine methane recovery technologies in the context of coal and trona mines that are currently emitting methane and eligible under the proposed protocol. Only 30 abandoned mine methane capture projects exist, about 10 of which are continuations of pipeline injection from active mines and thus ineligible under the protocol, so there are approximately 20 protocol eligible projects at over 400 mines that have closed since 1972 which were considered "gassy" at time of closure. This is the population from which mine methane emissions are estimated for the U.S. EPA's Greenhouse Gas Inventory Report. The U.S. EPA's Coalbed Methane Outreach Program has identified this population of 400+ mines as having potential for projects and manages a database of abandoned mines as a resource for project developers for the explicit purpose of identifying potential project sites.

Upon further analysis of abandoned mine methane project data provided by stakeholders, ARB staff concluded that continuing pipeline injection activities after abandonment is common practice and considered business-as-usual. The intent of this change is to exclude the crediting of methane destruction that would have otherwise been sent to a pipeline in the absence of the protocol. Similar to active underground mines, this would require that all abandoned mine methane from any methane sources connected to a natural gas pipeline while active be made ineligible for offset crediting. To realize the intent of this exclusion, abandoned mine methane recovery activities at mines that injected into a natural gas pipeline must not capture and destroy mine methane from newly drilled wells as it is assumed that methane from this source would have otherwise been injected into a pipeline. This ensures that the MMC protocol is incentivizing mine methane capture that would not otherwise take place in a conservative business-as-usual scenario therefore resulting in real, additional offset credits.

A commenter proposes evaluating additionality based on the number of credits issued that would be issued under the protocol. ARB staff assesses additionality on the potential projects that can be implemented and not on the percent of

[254] Title 30, Code of Federal Regulation, 75.323, 2006 , (as cited in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 3, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf.

[255] California Air Resources Board (2013) California Air Resources Board's Process for the Review and Approval of Compliance Offset Protocols in Support of the Cap-and-Trade Regulation. *available at* http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf (as referenced in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 1, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf).

greenhouse gas reductions at existing projects. This process to assess additionality is consistent with the evaluation of the four existing adopted compliance offset protocols. Regardless, ARB staff modified section 3.4.2(b)(4) of the MMC protocol through 15-day revisions to exclude pipeline injection as an eligible end-use management option at abandoned underground mines that injected mine methane into a natural gas pipeline while active, an activity already deemed to be common practice and therefore ineligible for the purpose of this protocol.

ARB staff disagrees with the comment asserting that the existence of abandoned mine methane capture projects without carbon finance is evidence that the protocol will generate non-additional emission reductions. The comment states that seven abandoned mines had active projects not affiliated with carbon finance when in fact there are only five such mines. 25 of 30 abandoned mines that had projects beginning after 2000 were registered in the voluntary carbon market. The comment also quotes an unnamed industry expert who suggests that 5-10 abandoned mine methane recovery projects would be implemented as a result of the MMC protocol. Based on discussions with technical working group members, staff expects approximately 5-10 projects to emerge within just the first few years of protocol adoption, and disagree with the commenter's stated facts and the conclusions reached therefrom. Moreover, staff recognizes that various forms of utilization of methane that results in energy production, can, in some circumstances, be financially viable without carbon finance. This does not conflict with the Cap-and-Trade Regulation as a financial additionality test is not required. In developing the Cap-and-Trade Program, ARB instead opted to pursue the performance standard approach. This approach streamlines the calculation of project baselines and determination of the additionality of projects by using standard eligibility criteria that ensure projects are additional. By establishing the standardized criteria in the Compliance Offset Protocol, there is less subjectivity by verifiers or offset project developers as to whether a project may be additional and this supports consistent quantification rigor in the offset program.

Please note that a more detailed response to the specific issue of additionality policy, as it relates to the proposed MMC protocol, can be found in responses to 15-day comment J-1.19 in this chapter and 45-day comment J-1.15 in Chapter IV of this Final Statement of Reasons document.

It should be noted that, as part of their 15-day comments, Stanford students resubmitted some of their 45-day comments. As these written comments are duplicative, responses to comments contained within both comments can be found in response to 45-day comment J-1.16 in Chapter IV of this Final Statement of Reasons document.

Additionality Policy

J-1.19. Comment: We request that the Board release the basis, and supportive data, on which it has made its performance standard evaluations.

In its descriptions of what project types meet the Performance Standard Test, the Protocol refers several times to a particular project type not being "common practice." Because such an assessment is critical to the additionality of the emissions reductions credited under the Protocol, the basis, including criteria and supporting data, on which these assessments were made should be made available for public review and comment. (STANFORD 5)

> **Response:** See response to 45-day comment J-1.16. Moreover, ARB staff determined that pipeline injection at active underground mines was common practice by reviewing an assessment by SAIC during the development of the Climate Action Reserve's Coal Mine Methane Project Protocol. This document, available at http://www.climateactionreserve.org/wp-content/uploads/2009/10/Reserve-CMM-Performance-Standard-Analysis-Report.pdf, was made available to the Technical Working Group and a link to the report is available from ARB's mine methane capture website in addition to being included in the Initial Statement of Reasons. An assessment of existing methane capture and destruction activities at abandoned mines was based on data provided by Ruby Canyon Engineering which was added to the rulemaking record on March 21, 2014 and available at: http://www.arb.ca.gov/regact/2013/capandtrade13/5rcecomm.pdf. The content of this document can also be found in response to 45-day comment J.1.13 .
>
> *It should be noted that, as part of their 15-day comments, Stanford students resubmitted some of their 45-day comments. As these written comments are duplicative, responses to comments contained within both comments can be found in response to 45-day comment J-1.16 in Chapter IV of this Final Statement of Reasons document.*

Incentivizing Coal

J-1.20. Multiple Comments: Coal is the biggest contributor to climate change but nonetheless the mining industry wants to get carbon credits from "capturing and destroying methane," which includes flaring offsets, and incentivizes more coal mining and fossil fuel extraction and infrastructure like pipelines.

We must stop this insanity and immediately cancel methane offsets. (THERULES)

Comment: Please cancel the proposed Mine Methane Capture Protocol. This protocol undermines the intent and effectiveness of AB32. Incentivizing dirty fossil fuel extraction with subsidies for marginally better performance is not how we transition to a high tech clean energy economy. California is already a world leader in this space - resources and offsets from AB32 must go to building a clean energy economy, protecting and regenerating farmland and rangelands, and creating jobs and infrastructure in urban communities. This does none of the above. (SHATTUCK)

Comment: Please do not proceed with the proposed Mine Methane Capture Protocol (MMCP) in California's Global Warming Solutions Act AB32. The National Resources Defense Council has said it well:
"And the Sierra Club has raised concerns about the potential that increased revenues for coal mine owners from offset sales could increase coal production, a point that was also raised by the Stanford clinic."
(http://switchboard.nrdc.org/blogs/pmiller/coal_mine_methane_offsets_a_ba.html)
(MILLER)

Comment: Promoting coal mining through mine methane capture offset projects? How does subsidizing coal mining count against global warming? Much less count against global warming enough to be used to exempt mining in a SECOND location on the ground its emissions are being compensated for? This is lunacy. (LOHMANN)

Comment: We are particularly concerned that offsets will fuel further mining and fossil fuel expansion, which are completely contrary to addressing climate change. (AAO)

Comment: On the one hand, capturing this methane has large climate benefits at very low cost, which can be captured by offset an offset protocol, but we raise two concerns that we believe need to be addressed. First, ARB staff's economic analysis has not yet assessed the specific effects we expressed concerns about. That is the increase on mining profits specifically from offsets projects which destroy drainage methane at active underground mines. ARB has done a case study analysis of three projects, but they haven't done case study analysis of specifically drainage methane from active underground mines. We understand these profits to be substantial and large enough to keep some mines operating longer than they otherwise would have. (STANFORD 6)

Response: See response to 45-day comment J-1.17.

Not Incentivizing Coal

J-1.21. Multiple Comments: As to the ARB staff economic analysis, SCI finds it clearly and logically demonstrates that the MMC protocol will not be a factor in any future increase in US coal production. Coal production is driven entirely by demand. As much coal will be mined in the US as there is a demand for the product and no more. Economic incentives to reduce coal mine methane emissions will have no effect on this relationship and will not increase domestic coal mining activity. To the contrary, the opposite is likely to be true since capital invested by coal companies to reduce methane emissions will not be available for investments to increase coal production capacity or improve mining productivity. (SOLVAY 2)

Comment: The "Mine Methane Capture Protocol and Mining Economics" analysis is very conservative and yet still demonstrates that MMC projects will not impact the financial standing of coal mines. It will not encourage development of new mines, nor will it prolong the life of operating mines. Coal mining will continue as it did before the MMC protocol, however mines that would otherwise vent methane will now have a means to recover some of the costs of reducing their GHG emissions. (ECC)

Comment: We are cognizant that some are concerned that the protocol may encourage additional coal production through economic incentives that will be enjoyed by those that reduce emissions of coal mine methane: this is wrongheaded. Any actions that are taken to reduce emissions of coal mine methane in any of its forms provide local and global environmental benefits. Worldwide, coal mine methane is a source of clean burning fuel and contributes to the health and welfare of people that would otherwise not have access to clean energy. (UNECE)

Comment: With regard to whether MMC projects would enable more coal mining than would otherwise occur, PG&E concurs with ARB that MMC projects would not contribute to additional mining because of the small returns on MMC projects and because coal is an increasingly global commodity whose production is predominately influenced by market fundamentals. (PGE 4)

Comment: The additional economic analysis provided by ARB staff that assesses the MMC protocol's potential affect on future mining projects is a welcome addition to the rule-making record. The report provides further concrete rationale in favour of the approval of the protocol, and should serve to alleviate the concerns of critics that claim the protocol could incentivize increased coal mining. (IETA 2)

Comment: I'd like to thank the staff for their economic analyses and wading through some very complex and often passionate issue.

I just want to make a few points. There's been a lot of discussion so far about this Mine Methane Capture Protocol would be a boon to coal miners. I would point out to the Board that at least to this point and to my knowledge there have been no coal mine operators that have testified at any of these hearings. And there have been no coal mine operators that have submitted any comments. I would suspect if this were such a boon to the coal miners and their industry, they would be lining up in support of this protocol. And yet, they don't seem to be found anywhere in this process.
We agree with the staff's conclusion that the Mine Methane Capture Protocol is not a boon to the coal miners. This is actually an insignificant part of their mine operations. And in fact, it's actually difficult to get them to pay attention to these projects because it's not core to their business, and it's not an economically important part of what they do. It's not regulated by the federal government. It's not important to their bottom line. They don't have the expertise to develop these projects. In fact, they rely on companies like ours and other California-based organizations to develop these types of projects. With respect to the models that have been presented in opposition to this, I would just point the Board's attention to the fact that, in our view, and I think the view of others, these models don't present an accurate picture upon which either a coal mine operator or an investor would make a financial decision. Their analyses, which don't consider the

initial capital costs of the project, the ongoing capital costs of the project, the ongoing operating costs of the project, and basically they just take revenues and apply it to the bottom line of a coal mine and distort the actual economics of these projects with respect to a mine's operations.

I would point out that the coal mine industry is under enormous pressure. And the tail is not wagging the dog here. These projects are not what will incent new coal mining. Coal mining is under pressure from a lot of different places. But most specifically, it's the impact of cheap and abundant natural gas that's putting pressure on the coal mining industry. If you look at quarter on quarter tonnes mined in the United States, as of Q4 2014 tonnes mined were down 6.8 percent. It shows if you look at coal tonnes mined over time, it's actually an industry that's already in steep decline.
In the end, this is really about funding environmental controls that would otherwise not be funded because these emissions are not regulated. And with that, I urge to Board to approve the Mine Methane Capture Protocol. (CE2CAPITAL 4)

Comment: Finally, PG&E would like to add to the course of support on the mine methane capture protocol. We agree with staff's analysis that this will remove a potent greenhouse gas from the atmosphere, with the negligible impact on coal mine revenues. (PGE 5)

Comment: My name is Jerry Gureghian. I'm the Chief Executive Officer of Green Holdings, a Los Angeles based developer of mine methane capture projects. And I spoke to you last October. Thank you for providing me with the opportunity to speak before you again. Along with Biothermica and Verdeo Sindicatum, we develop most of the mine methane capture projects. And over the past years, we've been hearing the same erroneous arguments surrounding economic benefits of this offset protocol, including the one that's being presented by the Stanford Law Group.

I'd like to clarify once and for all some points on this argument. First of all, a model that shows a windfall to coal mine operators is flawed, because first and foremost, the argument "does not use a model which is economic analysis." And number two, why? Because it doesn't take into account any up-front capital cost which the EPA placed conservatively at $10 million per project. It overstates capture of the mine. And last but not least, it doesn't take into account the cost of keeping these projects going, which is quite costly.

Let me provide you with a sense of how costly. In the past five years, my colleagues and I have met with all the major and many smaller coal mining companies. And for the sum total of our efforts has resulted in convincing three coal mines to implement two projects. Just two projects.

Which brings me to my second point, which I think was covered by Greg Arnold from CE2 Capital earlier. When was the last time a representative of the coal industry bothered to call you, make a public comment, or show up at a hearing? You'd think if the MMC protocol was going to generate an additional $600 million, at least one of them would be up here advocating for the protocol or singing the Board's praises. No. Why? Because, on average, in a coal mine the generates about a billion dollars a year in revenue, electrical power costs account for about $20 million. Whereas, the annual revenue from an MMC project is going to be about $2 million. That's not even ten percent of a mine's electrical utility bill. After we deduct our operating costs and capital costs and our share of the project, the mine only receives a fraction of that revenue. (GREEN 2)

Comment: I'm here to speak to support the Coal Mine Methane Protocol. I just want to restate a couple things. First to restate again what Greg Arnold said. Coal industry is declining. Production is declining. Six percent might not sound like something big, but in the coal industry, that's very, very important and a very large number in terms of tonnes. Mine expansion isn't happening. New mines aren't opening. But methane will continue to be emitted. It is a natural product. It comes along with any coal. (TOOLE ONEIL 3)

> **Response:** Thank you for the support. Since these comments are outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. This topic was explored in detail during the MMC protocol development process to ensure the proposed MMC protocol met the regulatory requirements to account for market shifting leakage resulting from projects implemented under the MMC protocol. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study as part of the 15-day revisions. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis was added to the administrative record of this rulemaking along with the 15-day notice, and is available in electronic form on the ARB rulemaking webpage at:
> http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

Regulatory Compliance

J-1.22. Comment: 3.8 Regulatory Compliance and Figure 4.2

- We interpret the Regulatory Compliance requirement to mean that any regulatory or other legal enforcement actions on the methane drainage system operated by the mine, including enforcement actions resulting from MSHA health and safety inspections, could cause the offset project, operated by the developer, to be ineligible for a full crediting period. This is because the methane drainage system is included within the project boundary according to Figure 4.2.

- By including the gas drainage system in the physical offset project boundary, ARB is not recognizing the fact that the methane drainage system (below ground) and methane utilization project (above ground) are usually controlled and operated by two different entities, the mining company and offset project operator respectively.
- Inclusion of the methane drainage system in the project boundary may make sense from an emissions standpoint, but when you add the regulatory compliance provision it can have unintended negative consequences for offset project viability.
- With the exception of some U.S.-based CMM-gas pipeline injection projects and most international CMM-fired on-site boiler projects, the typical business model worldwide is for an independent 3rd party to be the CMM project developer, and, in many cases, the project operator.
- Project developers or investors may be wary of the ARB regulatory compliance provision without further clarification from ARB. It adds substantial risk since the developer/investor would have absolutely no control over anything below the surface, including the methane drainage system. The mine could be cited for violations followed by an enforcement action with respect to the drainage system, and this would make the offset project ineligible for credits during an entire reporting period up to a year. (EPA 2)

> **Response:** The MMC protocol requires that projects meet the regulatory compliance requirements set forth in section 95973(b) of the Regulation. Pertaining to the comment, the Regulation states that a project is out of regulatory compliance if the project activities were subject to enforcement by a regulatory oversight body during the Reporting Period. As that language suggests, regulatory compliance is specific to the offset project activities, not the mine as a whole. The commenter's example of enforcement action by MSHA against the mine's methane drainage system would not represent nonconformance with the regulatory compliance requirement on the part of the project because the operation of the methane drainage system is not considered part of the offset project activities. The methane drainage system is in fact not represented in the offset project boundary in figure 4.2 as staff recognizes that this is often outside of the control of the Offset Project Operator or Authorized Project Designee. Rather it is the mine gas collection and destruction equipment, under the control of the project, which is included. This constitutes equipment that would capture and destroy mine methane otherwise emitted from a methane drainage system.

Definition of Offset Project Operator (OPO)

J-1.23. Multiple Comments: We also support the expansion of the definition of "Offset Project Developer" within the proposed MMC protocol to include not just the mine operator but also the entity that owns or leases the equipment used to capture or destroy mine methane (section 3.3(d)(2)). (IETA 2)

> **Response:** Thank you for the feedback. Staff recognizes that requiring a mine operator to be the OPO is overly restrictive and has revised this section of the proposed MMC protocol to also allow for owners and operators of the equipment used to capture and destroy methane to be OPOs.

Hyperbolic Emission Rate Decline Curve

J-1.24. Comment: We note that the Protocol now includes provisions for OPO's to use mine-specific measurements, including measurements of methane leaking from natural gas seeps at abandoned mines, rather than default average values, when calculating the hyperbolic decline curve used to establish baseline emissions for abandoned mines methane (AMM) projects. We appreciate that the Protocol text includes a provision for the Executive Officer to approve of any calculations of hyperbolic decline curve values based on mine-specific measurements. What we do not see is any clarification of provisions for how individual measurements made at natural gas seeps would be extrapolated to represent all methane emissions from an abandoned mine. In particular, would extrapolation spatially across a mine area be allowed from single point measurements? If so, we are concerned about the possibility that such measurements could inaccurately inflate the total estimated quantity of methane leaking from an abandoned mine. Clarifying text that specifies more precisely how the Executive Officer will evaluate measurements from natural gas seeps would help avoid the potential for overestimating baseline emissions. Inaccurately high baseline emissions are a concern because the hyperbolic decline curve estimate sets the total amount of methane that can be credited for being destroyed. Because the hyperbolic decline curve is an estimate of the total methane that would otherwise have leaked to the atmosphere, determining how to combine measurements at multiple seeps is essential to ensuring the integrity of the Protocol. (STANFORD 5)

> **Response:** Thank you for the comment. Staff agrees with the commenter that baseline emissions must be reflective of accurate and conservative estimates. Offset Project Operators or Authorized Project Designees may elect to use either default hyperbolic emission rate decline curve coefficients or hyperbolic emission rate decline curve coefficients derived from measured data at the mine. For projects that elect to derive mine-specific decline curve coefficients, text was added to the MMC protocol allowing measurements to be taken from natural gas seeps in addition to the pre-existing wells or boreholes open to the atmosphere. By incorporating natural gas seeps, baseline emission estimates will be more reflective of the emissions expected from the mine in the absence of the project. The flow of mine gas from pre-existing wells and boreholes and natural gas seeps must be measured and used to calculate the mine-specific hyperbolic emission rate decline curve coefficients per the instructions in section 5.4.1(u)(1)-(4). Offset Project Operators or Authorized Project Designees must incorporate the measured data into the decline curve, which is itself a conservative model of

emissions, per section 5.4.1(u)(5)(6). If an Offset Project Operator or Authorized Project Designee elects to use mine-specific decline curve coefficients, they must demonstrate to the satisfaction of the Executive Officer that the coefficients derived from the measurement of pre-existing wells and boreholes open to the atmosphere and natural gas seeps are equally or more accurate than the default coefficients.

ARB staff may release guidance in the future related to the construction of hyperbolic emission rate decline curves. The MMC protocol employs conservative baseline scenarios; the principle of conservativeness will not be jeopardized by the additional language pertaining to the measurement of natural gas seeps.

Business-As-Usual

Comment: The State of California's Global Warming Solutions Act's proposed Mine Methane Capture Protocol has extremely strong potential to become a major driver of national and international coal mining and fossil fuel extraction in Indigenous Peoples' and non-Indigenous lands, as well as profiteering and increased environmental degradation. The Protocol purports to be about the environmentally motivated capture and destruction of methane for offsets. However, it actually incentivizes and subsidizes the development of additional and potentially major coal mining and natural gas extraction operations, including flaring and burning, in existing and future coal and trona[2] mine areas. It represents not just business-as-usual for the fossil fuel industries, but a future increase in fossil fuel extraction, with expansions in extent, production, output, and infrastructure, including refineries and pipelines, together with permits to pollute even more. (BULLA)

Comment: The State of California's Global Warming Solutions Act's (AB32) proposed Mine Methane Capture Protocol (MMCP) [1] has extremely strong potential to become a major driver of national and international coal mining and fossil fuel extraction in Indigenous Peoples' and non-Indigenous lands, as well as profiteering and increased environmental degradation. The Protocol purports to be about the environmentally motivated capture and destruction of methane for offsets. However, it actually incentivizes and subsidizes the development of additional and potentially major coal mining and natural gas extraction operations, including flaring and burning, in existing and future coal and trona[2] mine areas. It represents not just business-as-usual for the fossil fuel industries, but a future increase in fossil fuel extraction, with expansions in extent, production, output, and infrastructure, including refineries and pipelines, together with permits to pollute even more. (MARTINEZ)

Comment: State of California's Global Warming Solutions Act's (AB32) has the very strong potent potential to become a major driver of national and international coal mining and fossil fuel extraction in Indigenous Peoples' and non-Indigenous lands, as well as profiteering and increased environmental degradation. The Protocol is said to be about environmentally motivated methane capture and destruction for methane offsets. However it actually incentivizes and subsidizes the development of additional and potentially major coal mining and natural gas extraction operations, including flaring and burning, in existing and future in coal and trona mine areas. It represents not just business-as-usual for fossil fuel industries, but a future increase in fossil fuel extraction, with expansions in extent, production, output, and infrastructure including refineries and pipelines, together with permits to pollute more. (GILLESPIE)

> **Response:** Staff disagrees that the MMC protocol represents business-as-usual for the mining industry. The assessment of additionality for the MMC protocol was done in accordance with the published ARB process for the review and approval of compliance offset protocols.
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> > The GHG emissions reduction must be additional, or beyond any reduction required through regulation or action that would have otherwise occurred in a conservative[256] business-as-usual scenario.[257] In order for ARB to ensure offset credits are additional, ARB would not adopt a protocol for a project type that includes technology or GHG abatement practices that are already widely used.[258]
>
> This ensures that the MMC protocol is incentivizing mine methane capture that would not otherwise take place in a conservative business-as-usual scenario therefore resulting in real, additional offset credits.
>
> A detailed response to the other concerns raised in these comments is provided in Attachment A of this document: Response to Comments on the Environmental Assessment Prepared for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms.

Offset Project Commencement

J-1.25. Comment: The term "offset project commencement" is used in contradictory ways in the Protocol. We recommend that the Board resolve this contradictory language to avoid confusion about project eligibility, and in a way that preserves the restriction that destruction devices not installed as an offset project are ineligible for crediting. Section 3.6 provides the definition of "offset project commencement" as "the date at which the offset project's mine methane capture and destruction equipment becomes operational." But a "qualifying device" is defined in the definitions section as "a

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256 "Conservative," in the context of offsets, means "utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements." Title 17, California Code of Regulations, section 95802(a).

257 "Business-as-usual scenario" means "the set of conditions reasonably expected to occur within the offset project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends." Title 17, California Code of Regulations, section 95802(a).

258 California Air Resources Board (2013) California Air Resources Board's Process for the Review and Approval of Compliance Offset Protocols in Support of the Cap-and-Trade Regulation. *available at* http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf (as referenced in the Staff Report and Proposed Compliance Offset Protocol Mine Methane Capture Projects (2013) at p. 1, *available at* http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf).

destruction device that was not operational at the mine prior to offset project commencement. . . .” This part of the definition of qualifying device is meaningless because offset project commencement is defined as the date at which the offset project’s mine methane capture and destruction equipment becomes operational in Section 3.6. That is, a qualifying device is defined in the Protocol as a destruction device that wasn’t operational before it was operational.

It seems that the Board actually intended that the Protocol should not credit mine methane captured by destruction devices that were installed prior to being an offset project. This could mean prior to project listing, or following the terms of the implementing cap-and-trade regulations themselves, it could mean prior to one year before project listing. The regulations specify that any technology for which construction began earlier than one year prior to project listing is not eligible for offset crediting, specifying that this requirement applies to projects that start construction after January 1, 2015. (Cal. Code of Reg., tit. 17, section 95975(h).)

We note that the regulation contains the following definition of “Offset Project Commencement” in the definitions section: “the date of the beginning of construction, work, or installation for an offset project involving physical construction, other work at an offset project site, or installation of equipment or materials.” Preserving this meaning of “offset project commencement” from the applicable regulation, we recommend that the Board replace the phrase “offset project commencement” with “offset project listing” or “one year before offset project listing” throughout the Protocol, except in Section 3.6, where “offset project commencement” is defined for this Protocol. We believe that this change reflects the intended meaning of “offset project commencement” used throughout the Protocol and also is in line with Section 95975(h) of the regulations. Preserving this meaning is important in keeping with the intention of the Board’s offset program, and the requirements of AB 32, that the program support new activities that would not otherwise have occurred on their own and avoid crediting “business as usual” activities that were already happening or going to happen without the offset program. We recommend the following clarification: The Protocol’s definition of “non-qualifying destruction device” as “a destruction device that is. . . operational at the mine prior to offset project commencement. . .” is meaningless because “offset project commencement is *defined* as the date at which the offset project’s mine methane capture and destruction equipment becomes operational.” (Section 3.6). In resolving this language, the Board should make sure the following provisions are preserved:
1. Devices that were installed prior to the date of project listing, or more than one year prior to project listing, should be considered ineligible for crediting, and
2. Any active underground mine that injected drainage methane into a pipeline should not be able to do so as an offset project after abandonment.

We believe that the following changes to the Protocol language retain the Board’s intended meaning which we understand as including the two bulleted points just above.

We first note that the definition of Offset Project Commencement in the Protocol matches the definition of Offset Project Commencement of in the cap-and-trade regulation. We believe that this definition should not be changed in the process of resolving the contradictory language in the Protocol:

Section of the Protocol: § 3.6. Offset Project Commencement.
(a) For this protocol, offset project commencement is defined as the date at which the offset project's mine methane capture and destruction equipment becomes operational. Equipment is considered ~~*operational*~~ operational on the date at which the system begins capturing and destroying methane gas upon completion of an initial start-up period.

Another reason not to change definition of "offset project commencement" in the Protocol is to preserve the meaning of section 95975 of the cap-and-trade regulation for this Protocol This section of the regulation mandates that an offset project must be listed within one year of "offset project commencement," where "offset project commencement" is defined in the regulation as the beginning of construction work or of installation of equipment or materials.

We suggest that the definition of "non-qualifying device" from the Protocol be changed in the following manner (our suggested changes are double underlined and double cross out):

DEFINITIONS:
(33) "Non-Qualifying Destruction Device" or "Non-Qualifying Device" means a destruction device that is either operational at the mine prior to offset project ~~commencement~~ listing or used to combust mine methane via an ineligible end-use management option per section 3.4. A destruction device that is operational at the mine prior to offset project ~~commencement~~ listing is considered a non-qualifying destruction device even if retrofitted thereafter. Methane destroyed by a non-qualifying device must be monitored for quantification of both the baseline and project scenarios.

It is important that devices that were installed prior to the date of project listing (this seems to be what is meant by Protocol's definition of non-qualifying device), or more than one year prior to project listing (specified in new changes to section § 95975(h) in the cap-and-trade regulation), remain ineligible in order to prevent the participation of non-additional projects in the Protocol. If a project is additional, project developers should be motivated to comply with Protocol requirements in a timely manner. A project developer that realizes the restriction months or years after the project is operational most likely did not need the offsets income to implement their project.

We suggest the same change (replacing the word "commencement" with "listing") in the following sections: Definition of "qualifying device", 2.1(b), 2.2(b), 2.3(b), 2.4(b)
We note, that in resolving this language, it is also important not to change the meaning of section 2.4(b) of the Protocol which specifies that an active mine that pipeline injects cannot then generate offset credits from that same capture system once the mine is abandoned. We provide a detailed defense of this restriction in Section #4 above. (STANFORD 5)

Response: Thank you for the comment. Since this comment is outside of the scope of the 15-day changes to the MMC protocol, no response is necessary. Nevertheless, ARB staff does not believe that there is a conflict with the offset project commencement date language in the protocol. Staff does not believe that the suggested changes are necessary for the MMC protocol to be implemented as intended. In fact, given that offset projects are regularly listed after project commencement, the proposed change would weaken the intention of the protocol to disqualify destruction devices that were in operation prior to offset project commencement.

General

J-1.26. Comment: SCI does want to clarify one aspect of the MMC Compliance Offset Protocol. Pages 21 -22 of the Protocol state, with respect to underground mine methane, "[p]ipeline injection of mine methane extracted from mine drainage systems at active underground mines is common practice and considered business as usual." Given that captured mine methane at an active mine must necessarily be transported by on-site pipelines to on-site facilities in order to destroy the methane at a central location or to combust the methane in on-site appliances, SCI assumes that the deletion of "off-site consumption" found in early versions of the Protocol was in error. SCI also notes that the Summary of Proposed Modifications on pages 26-27 talks about this change with respect to pipeline injection "after abandonment" – an inconsistency with the language in the protocol that refers to "active underground mines." (SOLVAY 2)

Response: For the purposes of the MMC protocol pipeline injection is considered the injection of mine methane into a pipeline for off-site consumption. Transport of mine gas or mine methane for on-site destruction is not considered pipeline injection and is eligible for all project types. The change to section 3.4.2(b)(2)(A) was simply a matter of eliminating redundancy in the protocol. The removal of the words "off-site consumption" was not intended to imply that on-site transport is prohibited.

The language cited from the Notice of Public Availability of Modified Text refers to the change to section 3.4.2(b)(4) that now excludes pipeline injection as an eligible end-use management option at abandoned underground mines that injected mine methane into a natural gas pipeline while active. This change was based on a re-evaluation of common practice at abandoned mines.
Please note that a more detailed response to the specific issue of additionality of abandoned mines, as it relates to the proposed MMC protocol, can be found in response to 15-day comments J-1.18 in this chapter and 45-day comment J-1.14 in Chapter IV of this Final Statement of Reasons document.

J-1.27. Comment: MMC projects require large capital expenditures that are difficult to securitize and are risky, both operationally and economically. Recognizing the full crediting period of a project is necessary to attract investments and achieve the goals of the Program. (ECC)

Response: Additionality of potential MMC projects is assessed in the same fashion as other ARB offset project types, at the time of project commencement and again at time of crediting period renewal. Like other non-sequestration compliance offset protocols, the crediting period for the proposed MMC protocol is ten years. Staff believes that this is sufficient time needed to make an investment attractive for most MMC projects.

K. SUPPORT FOR CAP-AND-TRADE AMENDMENTS

General Support for Amendments

K-1. Multiple Comments: We would also like to thank you and your staff for being open and accessible to our membership as this program develops (CCEEB 2).

Comment: As an initial matter, SDG&E and SoCalGas support most of the 45-day changes proposed last fall as well as the 15-day changes issued on March 21, 2014. Specifically, we strongly support the addition of a section on Natural Gas Suppliers and the provision for allocating allowances to natural gas suppliers for the benefit of their customers. The 15-day changes include additional improvements, including changes to clarify some of the registration and reporting requirements. SDG&E and SoCalGas appreciate the changes made to improve and refine the regulation (SEMPRA 4).

Comment: Powerex appreciates ARB's efforts to create and implement a comprehensive greenhouse gas ("GHG") cap-and-trade program. (POWEREX 2)

Comment: CARB staff has continued to work to resolve remaining issues from the 45-Day Proposed Amendments to the Cap-and-Trade Regulation ("45-Day Proposed Amendments"), as directed by the Board in Resolution 13-44. Calpine appreciates staff's efforts in this respect and, in particular, its efforts to address a number of concerns identified in our comments on both the 45- Day Proposed Amendments5 and the January 2014 Discussion Draft for the 15-Day Proposed Amendments ("Discussion Draft"). Some of these concerns addressed significant policy issues, such as the situation faced by legacy contract generators who have not been able to renegotiate their contracts to address GHG costs, while others involved details on auction participation and compliance instrument holding that, although seemingly narrow in focus, are critical to ensure a functional and robust market. In our view, the resolution to each of these concerns provided by the 15-Day Changes should support the development of a functional and robust market. Accordingly, we strongly support the 15-Day Changes and urge that staff proceed to finalize them as soon as possible. (CALPINE 4)

Comment: PEC is appreciative of the staff proposal and supports its adoption. (PANOCHE 2)

Comment: CPEM greatly appreciates the efforts of the ARB and its Staff in continuing to work with industry participants to create consistent and fair regulations that allow for a well-functioning market. (CPM 2)

Comment: CCEEB appreciates the work the California Air Resources Board (ARB) has completed since the adoption of the California Cap-and-Trade Program (Cap- and-Trade). We would also like to thank you and your staff for being open and accessible to our membership as this program develops.

CCEEB supports the adoption of the 15-day language due to some necessary programmatic changes that are time sensitive, supporting increased industry assistance and adoption of the mine methane control offset protocol.

We would also like to thank you and your staff for being open and accessible to our membership as this program develops. (CCEEB 4)

Comment: I want to echo the Chairman's statement that, from at least my perspective, cap and trade is working. It's working smoothly. And the efforts that you've been undertaking for the last year are going to make it work better. I've been working mostly on the issue of legacy contracts with staff and Board members. I want to thank both Board members and staff, specifically Steve Cliff and Rajinder Sahota and Richard Corey, for not only having public workshops, but really following through and meeting with stakeholders and listening to their concerns. We didn't get everything we wanted, but it's been a very good process. And we believe that the results are worth adopting.

We urge you to adopt the final regulation order today. And the reason I'm here is not only to thank you, but to explain that I also want to echo what Chairman Nichols said about the narrow window for adoption. With compliance instruments needed to be surrendered in November of 2014, it is urgent at least to the energy sector that these amendments be adopted today. And this starts at the plant level when people are wondering whether they have enough money to expand on capital for maintenance, for improvements. There are investments going on right now that are possible that will create more flexible capacity in this state so that energy gas plants can ramp up and down more frequently and better, which is good for the grid, and for reduction of greenhouse gases as well. All of these are dependent on certainty. This goes upstream from the plant to investors and lenders and credit rating. So from our point of view, it is imperative that this order be adopted today. And we urge your aye vote. Thank you very much. (PH 4)

Comment: Let me reiterate what Peter started off today with was sort of a thank you and a comment on all the work that staff has put into the proposal today. It's obviously been a long process since the initial set of recommendations for revisions came out. It has been very open and has been a remarkable process, especially on such a large rule, large set of amendments, and so many important issues on the table.

The rule today -- I stand up in front of you in had support of adopting the regulatory changes. You know, in our context, we evaluate it as an environmental group through the environmental integrity lens, and we think these changes -- they preserve the environmental integrity of the regulation, which for us is of utmost importance, is the paramount concern. At the same time, they recognize some important issues and expand the role and ability of the staff and the Board to look at things such as market oversight, improve some clarity around the rules and the regulatory provisions, and also do recognize some important cost considerations associated with how various businesses are treated in the program. (EDF 3)

Comment: In closing, I'd like to thank you, again, the ARB staff for all their dedicated work on this and for the opportunity to comment here. You know, we look forward to working together to find solutions that will protect the integrity of this market. (SCE 5)

Comment: Tesoro supports adoption of the proposed amendment today as there are important provisions in this package. We appreciate staff's hard work in bringing these proposals to you today. (TESORO 5)

Comment: The last three and a half years have required long hours and hard work from ARB staff and the stakeholder community, but I think we can all look back proudly. With five auctions completed, stable allowance prices, and linkage with Quebec underway, California is leading the nation and the world towards a cleaner future. (PGE 5)

Comment: I'd also like to thank the accessibility provided by the staff and the willingness to talk with us on a variety of issues over the entire time frame of the development of where we are today. It's been quite impressive from our perspective of the willingness of themselves to go out of their way at times to help us better understand some of their positions at times and to listen to our concerns. We support the adoption of the 15-day language. There are some very important elements in there, programmatic changes that are time sensitive supporting the increased industry assistance and the adoption of mine methane control offset protocol. (CCEEB 3)

Comment: Thank you for the opportunity to comment on the proposed amendments to the California cap on greenhouse gas emissions and market-based compliance mechanisms. We provided comments in April to the 15-day changes issued by the agency on March 21st. As indicated in that letter, we are in support of most of the proposed changes put forward last fall and on March 21st and want to thank staff for all the hard work they put into improving and refining these amendments. (SCGE 2)

Comment: I want to recognize at the outset the outreach process that the ARB staff used to arrive where we are at this rulemaking. We appreciate and recognize the continuing effort ARB exerted to communicate with and understand the issues identified by the stakeholders who are affected by the Cap and Trade Program. And while unresolved issues remain, the process recognized the dynamic and important balance between the transparent process and the need to protect confidential business information. (WSPA 6)

Comment: We support the efforts of staff and the Board to implement revisions to the cap and trade regulation to help us move forward with the ongoing success of the program. And we do urge that the revisions be adopted. (NCPA 4)

Comment: I appreciate -- first I wanted to say we appreciate very much all of the hard work and all of the effort of the Board and the staff for all of these regulatory updates. And I appreciate especially the very long days you've put in in the last two days. (TOOLE ONEIL 3)

Response: Thank you for the support.

Continued Administration

K-2. Comment: ARB Should Clarify the Effective Date of Regulatory Changes. Due to the extensive number of changes and new reporting requirements that may be required of entities subject to the Cap-and-Trade Regulation, many of which pertain to auction participation, ARB should clarify the effective date of the new regulation and clearly communicate to stakeholders which auction will be subject to the new requirements. Clarification of this information will provide covered entities and other market participants regulatory certainty and will facilitate compliance with the amended regulation (CCEEB 2).

Response: ARB staff anticipates the proposed amendments will take effect on July 1, 2014. Therefore, the first auction that will be subject to the new requirements will be the August 19, 2014 quarterly auction.

K-2. Comment: NCPA and its member agencies have been active participants in CARB's rulemaking to develop and implement the Cap-and-Trade Program (Program). NCPA appreciates CARB's ongoing efforts to work with stakeholders to refine the regulatory language and address issues that have arisen during the implementation of the Program. As noted in comments on the Proposed Amendments, it is important that the Program continue to be administered and operated in a manner that will allow the State to meet its greenhouse gas (GHG) emission reduction goals, while ensuring that electrical distribution utilities (EDU) complying with the Regulation are able to continue to provide safe, reliable, and reasonably priced electricity to California residents and businesses, and not impede their ability to comply with other State and Federal mandates. (NCPA 3)

Response: Staff agrees with the commenter and thanks the commenter for the support.

L. OPPOSITION AGAINST CAP-AND-TRADE AMENDMENTS

L-1. Comment: Cap and trade is a terrible idea. Don't do it. (KISSAM)

> **Response:** This comment is outside of the scope of the proposed 15-day amendments to the Cap-and-Trade Regulation so no response is required.

M. COMMENTS UNRELATED TO THE PROPOSED AMENDMENTS

Public Process

M-1. Comment: Outreach Process. It is important to recognize the continuing effort by ARB to communicate with, and understand, the issues identified by the many stakeholders who are affected by the C/T program. While unresolved issues remain, the process used by staff to develop the final proposal recognized the important and dynamic balance between a transparent process and the need to protect confidential business information associated with a market-based system to reduce GHG emissions. We appreciate the efforts by staff who went to great lengths to explore issues and identify possible solutions. (WSPA 5)

> **Response:** Thank you for the support of our public process for the proposed amendments.

Other Unrelated Comments

M-3. Comment: *[Note: This comment has been redacted due to the inappropriate nature of some of its contents.]* I come from Alberta and am very aware of Fracking and the damage it poses to Water tables. Look up Maskwacis AB. Used to be Hobbema AB. Economy will not save your sorry a****. Oil and Gas kills all fresh water. What are your grandchildren going to drink in the near future. Hmm. (ERMINESKIN)

> **Response:** This comment is outside of the scope of the proposed 15-day amendments to the Cap-and-Trade Regulation so no response is required.

N. DEFINITIONS

Tomato Processing

Comment. III. Typo in definitions for Aseptic tomato paste definition. The proposed definition covering Aseptic Tomato Paste reads:

> (16) “Aseptic tomato paste” means tomato paste packaged using ~~a system in which the product is sterilized before filling into pre-sterilized packs under~~ aseptic preparation ~~conditions.~~ Asceptic paste is normalized to 31% tomato soluble solids (TSS). Asceptic paste normalized to 31% TSS = (%TSS - 5.28_/(31 - 5.28).
>
> **Recommendation:** The last line “Asceptic paste normalized to 31% TSS = (%TSS - 5.28 / (31 - 5.28) should be corrected to read as follows:
>
> Aseptic paste normalized to 31% NTSS = (%NTSS – 5.28 / (31 – 5.28). (CLFP 3)
>
> **Response:** Thank you for the recommendation. These changes will be considered in a future regulatory amendment.

VI. PEER REVIEW

Health and Safety Code section 57004 sets forth the requirements of peer review of identified portions of rulemakings proposed by entities within the California Environmental Protection Agency, including ARB. Specifically, the scientific basis or scientific portion of a proposed rule may be subject to this peer review process. Here, ARB determined that the rulemaking at issue does not contain scientific basis or a scientific portion subject to peer review, and thus no peer review as set for in section 57004 was or needed to be performed.

ATTACHMENT A: FINAL STATEMENT OF REASONS

Response to Comments on the Environmental Assessment Prepared for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms

California Environmental Protection Agency

Air Resources Board

Released April 15, 2014
to be considered at the
April 25, 2014 Board Hearing

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Introduction

To meet the requirements of the California Environmental Quality Act (CEQA) under the California Air Resources Board's (ARB) certified regulatory program, ARB staff prepared an environmental analysis (EA) as part of the Initial Statement of Reasons (ISOR) for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Instruments. The ISOR was released for public review on September 6, 2013 for a 45-day public review and comment period that concluded on October 25, 2013 at the Board Hearing. There was one 15-Day change notice for the modified regulatory text, following the initial 45-day comment period. The 15-day changes were largely administrative and did not affect the environmental analysis in the ISOR and no revision or recirculation of the environmental analysis was required.

This document represents verbatim a subset of all the comments received during the 45-day comment period, the 15-day comment period, and at the October 2013 Board Hearing that raise significant environmental issues and ARB's written responses to those comments. Substantive responses are limited to comments that "raise significant environmental issues associated with the proposed action," as required California Code of Regulations, title 17, section 60007(a). ARB conservatively included comments and responses in this document if the comment raises an environmental issue area even if the comment does not directly pertain to the adequacy of the environmental analysis. This document includes environmental comments received outside of the 45-day review and comment period required by CEQA, namely environmental comments received during the 15-day comment period even though the EA was not recirculated or reopened for public review during that time. In accordance with the ARB certified regulatory program, the Board will consider the written responses to these environmental comments for approval prior to taking final action on the proposed amendments.

Staff will prepare written responses to all public comments, not just the environmental comments, for purposes of the Administrative Procedure Act. The complete written responses to all comments will be included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

For the purposes of this document, comments and responses have been separated between those relating to the proposed amendments, and those relating to the Compliance Offset Protocol Mine Methane Capture Projects (MMC Protocol). In this document, the individual comments are presented under the correspondence within which they were received, ordered alphabetically by COMMENT ID, and identified as shown in the example below:

COMMENT ID: *This is the abbreviation used to identify the comment correspondence in which the individual comments are contained.*

Name: *Person(s) submitting the comment*

Affiliation: *Affiliation of the commenter(s)*

Written/Oral Testimony: MM/DD/YYYY *Type of comment and date received*

45-day/15-day Comment #: 123 *Comment period and unique comment number. The unique ID number corresponds to the numbering in the FSOR.*

Comment: Comments received under the COMMENT ID are presented individually as shown in this example, beginning with "**Comment"** on the first line.

> **Response:** Responses are presented following each comment. Responses are indented from the left margin.

Commenters

The list below identifies the commenters that submitted comments related to the Environmental Analysis, and includes commenter information. This list is alphabetically ordered with an identification on when the comment was submitted to ARB.

ALA	Will Barrett, American Lung Association Oral Testimony: 10/25/2013
ANGELL	J. Angell, Private Individual Written Testimony: 04/02/2014
BARNES	Kathryn Barnes, Private Individual Written Testimony: 04/02/2014
BULLA	Jeanne Bulla, Private Individual Written Testimony: 03/31/2014
CCA	Bill Magavern, Coalition for Clean Air Oral Testimony: 10/25/2013
COVANTA 2	Ellie Booth, Covanta Energy Written Testimony: 04/04/2014
CULLENWARD 3	Danny Cullenward, Private Individual Written Testimony: 4/4/2014
EDF 2	Derrik Walker, Environmental Defense Fund Oral Testimony: 10/25/2013
FWW	Wenonah Hauter, Food & Water Watch Written Testimony: 9/26/2013
GILLESPIE	Sherri Gillespie, Private Individual Written Testimony: 04/03/2014
HAYES	Linda Hayes, Private Individual Written Testimony: 03/31/2014
HO	Kit Ho, Private Individual Written Testimony: 04/03/2014
MAES	Linda Maes, Private Individual Written Testimony: 03/31/2014
MARKS	Luan Marks, Private Individual Written Testimony: 04/04/2014
MARTINEZ	Juan Martinez, Private Individual Written Testimony: 04/02/2014
MOTL	Julie Motl, Private Individual Written Testimony: 03/31/2014
ROSENTHAL	Richard Rosenthal, Private Individual Written Testimony: 10/23/2013
SKINNER	Nancy Skinner, Assemblymember, Fifteenth District Written Testimony: 10/17/2013

STANFORD 4	Aaron Strong, Stanford University Oral Testimony: 10/25/2013
STANFORD 5	Barbara Haya, Stanford Law School Written Testimony: 04/05/2014
TAYLORR	Jeremy Taylorr, Private Individual Written Testimony: 03/31/2014
THORNBURGH	Jack Thornburgh, Private Individual Written Testimony: 04/02/2014

COMMENTS RELATED TO THE PROPOSED AMENDMENTS TO THE CAP AND TRADE REGULATION

COVANTA 2

Name:	Ellie Booth
Affiliation:	Covanta Energy
Written Testimony:	04/04/2014
15-Day Comment #:	113

Comment: New data show that the methane emitted by landfills and other sources is even more damaging than previously thought. Since the October 2012 Board Resolution and the CalRecycle study, the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report has updated the 100 year global warming potential of methane to 34 times as potent as CO_2 when climate-carbon feedbacks are included. Over a 20-year timeframe, identified in the February 10, 2014 proposed update to the Scoping Plan as a better reflection of what can be achieved in the near term by mitigation, methane is 86 times as potent as CO_2. This new data, and the shorter term perspective on methane, further demonstrates the positive characterization of EfW versus landfill from a GHG perspective and provides a sound basis to exclude the three EfW facilities moving forward.

> **Response:** As discussed in the Draft Proposed First Update to the AB 32 Scoping Plan (Scoping Plan Update)[259], ARB approved two resolutions to work with CalRecycle and other stakeholders to characterize emission reduction opportunities for handling solid waste, waste-to-energy, and landfilling, among other waste sectors. In light of these recommendations, ARB and CalRecycle are currently preparing a joint study to analyze maximum GHG emission reduction opportunities for these and other solid waste streams in the State. ARB will continue to work with CalRecycle and other State agencies to determine the most appropriate treatment of the waste sector under the Cap-and-Trade Program, and will make any necessary modifications to the Regulation pending the results of this ongoing study.
>
> In addition, the Scoping Plan Update also recommends that ARB develop a comprehensive strategy for mitigation of short-lived climate pollutants, including methane, by 2015. This will help ARB to continue to develop strategies that address methane emissions from the waste sector, identify opportunities for additional methane control at new and existing landfills, and identify important complements to ARBs efforts to reduce emissions of CO_2.

CULLENWARD 3

[259] California Air Resources Board. “Proposed First Update to the Climate Change Scoping Plan: Building on the Framework.” Released February 10, 2014. Available at: http://www.arb.ca.gov/cc/scopingplan/2013_update/draft_proposed_first_update.pdf.

Name: Danny Cullenward
Affiliation: Private Individual
Written Testimony: 04/04/2014
15-Day Comment #: 89

Comment: ARB's environmental analysis is legally insufficient because it fails to acknowledge the significant environmental harms caused by the safe harbors.

Although the proposed amendments are problematic enough on their own, ARB's failure to acknowledge the expected—and quite likely intended—consequences of its actions is all the more troubling. ARB's September 2013 Staff Report on the current proposed regulations contains an environmental analysis for the proposed regulations.[260] This analysis brazenly relies on misleading comparisons to avoid assessing the environmental impacts of the proposed regulatory changes. It must be updated to serve the most basic purposes of the California Environmental Quality Act ("CEQA"), which are to:

(1) Inform governmental decision makers and the public about the potential, significant environmental effects of proposed activities.

(2) Identify ways that environmental damage can be avoided or significantly reduced.

(3) Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.

(4) Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.[261]

Even as it implements major reforms that undermine the economic and environmental integrity of the carbon market, ARB nevertheless manages to stay silent on the expected environmental impacts. ARB's 2013 Staff Report falsely construes the proposed safe harbors as mere "clarifying language" that "would not affect the compliance responses available to [covered] entities from what was analyzed in the 2010 FED."[262] That reliance is misplaced because the 2010 FED analyzed a rulemaking that produced the original prohibition on resource shuffling, which did not include any safe harbors. In other words, ARB falsely claims that the current proposed safe harbors do not affect its prohibition on resource shuffling.

This is simply incorrect. The current regulation says only that "[r]esource shuffling is prohibited and is a violation of [Article 5 of the Cap-and-Trade Regulations]";[263] it says

[260] California Air Resources Board, Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Staff Report: Initial Statement of Reasons 1, 44 (Sept. 4, 2013).
[261] Cal. Code Regs. tit.14, §§ 15002(a)(1)-(4).
[262] California Air Resources Board, supra note 24 at 51 (citing California Air Resources Board, 2010 Cap and Trade Regulation, Appendix O: Functional Equivalent Document 1, 1 (Oct. 28, 2010)). ARB concludes its 2013 Staff Report analysis by stating that: "Resource shuffling was disclosed as a prohibited activity in the 2010 Regulation as analyzed in the 2010 FED. Therefore, the potential for adverse impacts associated with the proposed clarifications to this definition fall within the scope and scale of those previously analyzed." Id. at 59.
[263] Cal. Code Regs. tit. 17, § 95852(b)(2).

nothing about thirteen broad exemptions to this supposedly-preserved rule. As a result of the proposed safe harbor provisions, ARB's prohibition on resource shuffling will become an unenforceable formality. Between 30 and 60 million tons of CO2 have leaked or are imminently leaking as a result, exceeding any reasonable threshold for significance under CEQA.[264] Because the proposed safe harbors would radically modify the carbon market regulations as they currently exist, CEQA requires ARB to conduct an analysis of the environmental impacts.[265]

By claiming that it is not, in fact, changing its market rules, ARB suggests that adding multiple loopholes that undermine a critical market rule will have no environmental effect on the performance of its cap-and-trade market. Yet as my previous comment letter, ARB's own economic advisers (EMAC), and the observed resource shuffling transactions described in this letter show, the proposed regulatory changes have caused and will continue to cause significant leakage. In turn, this will lead to significant environmental consequences, as ARB put it when addressing leakage in its 2010 FED:

"If leakage occurs, the reductions in GHGs achieved by sources in California may be undone by a corresponding increase in emissions outside of California …. [Leakage] would likely lead to increased adverse environmental impacts outside of California, and would have negative effects on California's economy."[266]

Because the resource shuffling safe harbors have caused and will continue to cause significant environmental consequences—impacts ARB has never acknowledged or analyzed—ARB has not satisfied the basic requirements of CEQA. To comply, ARB must assess the environmental consequences of its proposed safe harbor regulations and evaluate the feasibility of alternative approaches.

> **Response:** The commenter suggests that the environmental analysis (EA) contained in Chapter III of the ISOR is inadequate because it classifies the amendments related to resources shuffling as "clarifying language." The commenter argues that this characterization is incorrect because the 2010 FED analyzed a rulemaking that produced a single prohibition on resource shuffling, which did not include any safe harbors.
>
> Staff disagrees that the proposed amendments related to resource shuffling are not clarifying in nature. Under the existing Cap-and-Trade Regulation (Regulation), resource shuffling is explicitly prohibited and was disclosed as a prohibited activity in the 2010 Regulation, as analyzed in the 2010 FED. Pursuant to Board Resolution 12-33, staff was directed to provide additional clarity relating

[264] See Cal. Code Regs. tit. 14, § 15064.4 (providing guidelines for determining the significance of impacts from greenhouse gases for the purposes of CEQA analysis).
[265] ARB could argue that the current regulatory proposal will have no significant changes to the status quo, but only if it acknowledges that the safe harbor regime is already in effect due to the November 2012 regulatory guidance document. Yet that admission would raise serious questions as to whether introduction of the regulatory guidance document constituted impermissible underground regulation that avoided the basic requirements of California administrative law, such as offering the public with formal notice and an opportunity to comment.
[266] California Air Resources Board, 2010 Cap and Trade Regulation FED, supra note 26 at 378 (discussing leakage in the context of a CEQA evaluation of an alternative policy design that would employ border adjustments to goods and services imported to California).

to the existing definition of resource shuffling, to provide guidance to in-state electricity generators and out-of-state electricity importers on actions that are already prohibited under the program. In Resolution 12-51, the Board directed staff to further refine the definition of resource shuffling and to identify situations that ARB would not consider resource shuffling based on Attachment A of Resolution 12-51. In consultation with State Utilities, ARB staff developed this clarifying language via an open public process, and released a public draft of this clarifying language in November 2012. Pursuant to board direction, the activities identified as “safe harbors” are not exemptions from the current prohibition, but rather serve to clarify it.

The commenter suggests that the EA is inadequate because it states that clarifying language related to resource shuffling would not affect the compliance responses available to entities from what was analyzed in the 2010 FED. Staff does not agree. The 2010 FED indicated the following four compliance responses are available to covered entities: (1) upgrade equipment; (2) decarbonization (fuel switching); (3) implement process changes; and (4) surrender compliance instruments. These compliance responses have not changed for in-state generators or out-of-state importers as a result of the proposed clarifying language related to resource shuffling.

Finally, the commenter argues that the EA must be updated in order to serve the purposes of CEQA, which are to inform decision makers, identify ways to avoid or mitigate impacts, provide alternatives if feasible, and disclose the reason for project approval in the case that significant projects are identified. Staff disagrees with the commenter. As discussed in the ISOR, the focus of the EA is to assess the potential for adverse impacts associated with incremental changes to the previously adopted program, as analyzed 2010 FED. The EA concluded that the proposed regulatory amendments to the Regulation would not result in any new significant adverse impacts or an increase in the severity of any significant impacts as previously identified in the 2010 FED, and may provide air emissions benefits as compared to current practices. Because the impacts of the proposed amendments fall within the scope and scale of those already analyzed in the 2010 FED, and the amendments do not result in any additional or more severe impacts than previously analyzed in the prior certified environmental documents, the EA concluded that no additional alternatives analysis for the amendments was required. (See Public Resources Code, section 21166.)

An alternative analysis for the MMC Protocol which identified impact identified in its environmental analysis was included in Appendix A to the ISOR. ARB's CRP requires that prior to adoption of an action for which significant adverse environmental impacts have been identified during the review process, that ARB consider all feasible mitigation measures and alternatives available which could substantially reduce such adverse impacts (California Code of Regulations, title 17, section 60006.). While an agency may approve a project with unavoidable adverse environmental impacts, CEQA requires the agency to make a statement in the record of its views on the ultimate balancing of the merits of approving the project despite the environmental impacts. As a result of this requirement, staff prepared a Findings and Statement of Overriding Considerations to be considered by the Board at April 25, 2014 public hearing.

Staff notes that this comment was received outside the 45-day comment period provided for the environmental analysis for purposes of CEQA. The following 15-Day change notice for the modified regulatory text was limited to review on those limited changes and did not reopen the CEQA comment period. Non-CEQA related aspects of this comment, such as enforcement of the resource shuffling prohibition, will be addressed in the FSOR prepared for the Regulation in accordance with APA requirements

EDF 2

Name: Derrik Walker
Affiliation: Environmental Defense Fund
Oral Testimony: 10/25/2013
Board Hearing speaker #: 44

Comment: There is, however, one element of today's package that creates tremendous concern for us. That is the extension of transition assistance to the refining sector. We believe that this decision is premature as research has not been finalized to demonstrate its necessity. In fact, WSPA's own analysis found that 100 percent transition assistance is unnecessary, not to mention that it won't make much of a difference to these very large petroleum companies.

We have excerpted WSPA's analysis in our written comments that we filed to the Board. What's more, the extension of this transition assistance amounts to between a $550 million and $750 million give away, money that could be invested to improve the environment and public health in communities that have suffered for decades from the effects of air pollution from refineries. We urge the Board to reject this extension of transition assistance.

> **Response:** The commenter argues that the additional transition assistance provided to the petroleum refining sector should not be approved, and suggests that the monetary value of these additional allowances should be invested to improve the environment and public health in communities which have increased air quality impacts as a result of refineries.
>
> The Regulation requires GHG reductions on a statewide level, but does not stipulate specific improvements or compliance actions by individual regulated entities. Moreover, the Regulation does not obviate any existing local or regional air quality regulations or control programs related to the management of toxic air pollutants in California. Local air pollution control districts and/or air quality management Districts (air districts) have primary responsibility for adoption and implementation of stationary and area-wide source emission control measures. The 2010 FED accurately reflects that local governments, notably cities and counties, have land use and permitting authorities (CEQA lead agency authority, zoning Ordinances and regulations, building codes, construction permits, etc.) that are applicable to facility-specific projects. Such projects may be undertaken as compliance responses and would be local improvements subject to project-level CEQA analysis and local permitting.
>
> In addition, the 2010 FED, to which the EA for the current amendments provides an addendum, also identified ARB’s commitment to an adaptive management approach to assess the effectiveness of the Regulation, and identify data trends that could indicate unanticipated or undesirable results. This monitoring and feedback approach lays out a framework to monitor the potential for adverse impacts that could result from action taken to comply with the Regulation,

including the proposed amendment to shift the first reduction in transition assistance for refineries.

Finally, staff would like to point out that in 2012, the Legislature passed and Governor Brown signed into law three related bills (i.e., AB 1532, SB 535, and SB 1018) providing direction on the establishment of the Greenhouse Gas Fund (created pursuant to Government Code section 16428.8), and the process for the allocation of auction proceeds to further the goals of AB 32. In enacting the implementing legislation, the Legislature stated its intent to direct resources to the State's most impacted and disadvantaged communities, in order to provide economic benefits as well as health benefits through additional emission reductions. A requirement of these statutes is that at least 25 percent of program funding must be allocated to projects that benefit disadvantaged communities and at least 10 percent of program funding must be allocated to projects located in disadvantaged communities. CalEPA is responsible for identifying disadvantaged communities outlined the investment plan to the Legislature. Identification criteria may include, but are not limited to, areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure or environmental degradation. ARB directs the commenter to the Cap-and-Trade Auction Proceeds Investment Plan: Fiscal Years 2013-14 through 2015-16[267], for additional information on the use of auction proceeds.

[267] California Air Resources Board. Cap-and-Trade Auction Proceeds Investment Plan: Fiscal Years 2013-14 through 2015-16. Released May 14, 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/auctionproceeds/final_investment_plan.pdf

ROSENTHAL

Name: Richard Rosenthal
Affiliation: Private Individual
Written Testimony: 10/23/2013
45-Day Comment #: 74

Comment: Prior to consideration of proposed amendment, an EIR should be undertaken to assess the environmental impacts of the proposed amendment. [This comment was provided in response to the proposed amendments related to clarifications on resource shuffling.]

> **Response:** In accordance with Public Resources Code section 21080.5 of CEQA, public agencies with certified regulatory programs are exempt from certain CEQA requirements, including, but not limited to, preparing environmental impact reports, negative declarations, and initial studies (14 CCR 15250). Staff prepared a substitute environmental document, referred to as an environmental analysis (EA) for the proposed amendments in Chapter III of the ISOR, pursuant to ARB's regulatory program certified by the Secretary of the Natural Resources Agency (14 CCR 15251(d); 17 CCR 60005-60007). The EA, as part of the ISOR, was released for public review on September 6, 2013 for a 45-day public review and comment period that concluded on October 25, 2013..[268] ARB also prepared a separate EA specific to the MMR Protocol in the ISOR for that proposed protocol in Appendix A to the ISOR for the proposed amendments.[269]
>
> In the EA for the proposed amendments, staff specifically analyzed the proposed amendments relating to the definition of resource shuffling, and the identification actions that ARB does not consider resource shuffling. In the EA, staff concluded that the intent of the proposed language relating to resource shuffling is to provide further clarification to electricity generators and importers regarding both prohibited and non-prohibited activities under the Regulation, and that the potential for adverse impacts associated with the proposed clarifications to this definition falls within the scope and scale of those previously analyzed in the environmental analysis certified for the Regulation in 2010 (referred to as the 2010 Functional Equivalent Document included as Appendix O to the 2010 ISOR). Staff concluded that the clarity provided to the definition and other administrative changes to the Regulation do not trigger any additional environmental review because these were not substantial changes to the regulation, substantial changes to the circumstances, or new information of substantial information that alters the analysis or conclusion discussed in the certified environmental analysis prepared for the Regulation in 2010. (See Public Resources Code section 21166.)

[268] http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf
[269] http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf

COMMENTS RELATED TO THE PROPOSED COMPLIANCE OFFSET PROTOCOL MINE METHANE CAPTURE PROJECTS

ALA

Name:	Will Barrett
Affiliation:	American Lung Association
Oral Testimony:	10/24/2013
45-Day Comment #:	67

Comment: Also wanted to briefly get into -- the echo also many of the comments related to the impacts of methane mine protocol and think more time is needed to evaluate the concerns raised today by several of the groups and academics that testified. At the national level, the American Lung Association supports the phase out of coal and a transition to cleaner energy sources for the climate air quality and localized public health benefits or damages associated with all phases of the coal use. We believe additional time is needed to review the protocol and urge you to take that time to do so just to ensure that any projects under that protocol do not incent more coal or probably result in non-additional projects going forward. So thank you very much.

Response: The limited use of offsets serves as an important cost-containment feature in the Cap-and-Trade Program, which reduces emissions and works in conjunction with other AB 32 measures that shift California's energy consumption toward renewable sources. The environmental analysis prepared for the proposed Mine Methane Capture Compliance Offset Protocol (MMC protocol) concluded that any potential impacts to air quality would be less than significant due to the requirement that all projects comply with all applicable federal, state and local laws and regulations. The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

The issue of additionality raised by the commenter will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

ANGELL

Name: J. Angell
Affiliation: Private Individual
Written Testimony: 4/2/2014
15-Day Comment #: 52

Comment: Proposed offsets for methane flaring are patently absurd, detrimental to effectively addressing climate change and to public health, especially for indigenous populations; thus do not approve this illogical insane proposal.

> **Response:** Staff disagrees with the commenter that allowing the flaring of mine methane is detrimental to effectively addressing climate change. CO_2, a greenhouse gas, is released when methane is destroyed via a flare or when combusted for productive utilization as allowed in the MMC protocol. Methane has a much higher global warming potential than carbon dioxide so the CO_2 emissions resulting from the destruction of methane still represent a reduction in terms of the climate impact. Nonetheless, the MMC protocol takes into consideration the release of CO_2 from the destruction of methane, regardless of the destruction method employed, and accounts for the impact of these emissions in the quantification methodologies. It is only the real, net emission reductions that are credited. The environmental analysis prepared for the proposed MMC protocol determined that implementation of MMC projects would result in beneficial impacts to greenhouse gas emissions. The environmental analysis further concluded that its potential impacts to resource areas related to public health such as air quality, hazards/hazardous materials, and hydrology/water quality would be less than significant due to the MMC protocol's requirement that all projects comply with all applicable federal, state, and local laws and regulations. The environmental analysis applies equally to potential projects on tribal and non-tribal lands. It is worth noting that the MMC protocol is not a compulsory regulation; rather the development of a MMC offset project is strictly a voluntary action.

BARNES

Name: Kathryn Barnes
Affiliation: Private Individual
Written Testimony: 4/2/2014
15-Day Comment #: 49

Comment: Do not capture and burn off methane gas. It is wasteful and creates global warming. It is one thing to use a resource, another to waste it.

> **Response:** The MMC protocol allows for a variety of end-uses for captured methane including productive utilization. Staff disagrees with the commenter that allowing the flaring (burning) of mine methane creates increased global warming. CO_2, a greenhouse gas, is released when methane is destroyed via a flare or when combusted for productive utilization as allowed for in the MMC protocol. Methane has a much higher global warming potential than carbon dioxide so the CO_2 emissions resulting from the destruction of methane still represent a net reduction in the terms of the climate impact. Nonetheless, the MMC protocol takes into consideration the release of CO_2 from the destruction of methane, regardless of the destruction method or employed, and accounts for the impact of these emissions in the quantification methodologies. It is only the real, net emission reductions that are credited. The environmental analysis prepared for the proposed MMC protocol determined that implementation of MMC projects would result in beneficial impacts to greenhouse gas emissions. It also found that the MMC protocol has the potential to both reduce a facility's reliance on fossil fuel and increase the supply of electricity and natural gas, both beneficial impacts of the MMC protocol.

BULLA

Name: Jeanne Bulla
Affiliation: Private Individual
Written Testimony: March 31, 2014
15-Day Comment #: 15

Comment: The State of California's Global Warming Solutions Act's proposed Mine Methane Capture Protocol has extremely strong potential to become a major driver of national and international coal mining and fossil fuel extraction in Indigenous Peoples' and non-Indigenous lands, as well as profiteering and increased environmental degradation. The Protocol purports to be about the environmentally motivated capture and destruction of methane for offsets. However, it actually incentivizes and subsidizes the development of additional and potentially major coal mining and natural gas extraction operations, including flaring and burning, in existing and future coal and trona[2] mine areas. It represents not just business-as-usual for the fossil fuel industries, but a future increase in fossil fuel extraction, with expansions in extent, production, output, and infrastructure, including refineries and pipelines, together with permits to pollute even more.

> **Response:** Only projects located within the United States are eligible under the proposed MMC protocol. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm
> The protocol in no way impacts the permitting process applicable to the mining industry. Project developers must meet the regulatory compliance requirements set forth in section 95973(b) of the Cap-and-Trade Regulation and offset credits will not be issued if a project is not in compliance with regulatory requirements.
>
> The commenter's claim that the MMC protocol represents business-as-usual will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on

the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

CCA

Name: Bill Magavern
Affiliation: Coalition for Clean Air
Oral Testimony: October 24, 2013
45-Day Comment #: 51

Comment: And thirdly, we oppose the adoption of the mine methane protocol. Others have testified as to the technical reasons why it shouldn't be adopted. I would just ask you to look at fundamentally what's happening here if this is adopted. You have a law which requires California to reduce California's greenhouse gas emissions. If this is adopted, then instead, what will happen is the state's polluters, instead of reducing their own pollution here in California, will send money out of state to the companies that mine coal, which can then use that money to dig up more coal, our dirtiest energy source, so it will be burned in other states and possibly other countries very much against what we're trying to do to reduce CO2 emissions. I would ask is that really the direction you want to go implementing this law.

> **Response:** The limited use of offsets serves as an important cost-containment feature in the Cap-and-Trade Program. The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at:
> http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

FWW

Name: Wenonah Hauter
Affiliation: Food & Water Watch
Written Testimony: 9/26/2013
45-Day Comment #: 5

Comment: On behalf of Food & Water Watch (FWW),[270] I write to express our organization's opposition to the September 4, 2013 "Proposed Compliance Offset Protocol Mine Methane Capture Projects."

Offsets are counterproductive and do not lead to real, additional, or permanent emissions reductions. Even worse, offsets generated from coalmine methane capture operations would further promote an emissions intensive and highly polluting fossil fuel.

As if offsets alone were not problematic enough, California's new initiative to generate offsets from coalmine methane capture projects creates additional specific problems. Supporting these offsets supports coal mining and ultimately coal burning power plants—a chain of processes that is highly polluting, degrades the environment, and adds significant amounts of greenhouse gases (GHGs) into the atmosphere. The point of an emissions reduction initiative is to *reduce* emissions, not support a process that creates additional emissions.

Coal is a fossil fuel, it is not renewable and it is one of the most highly polluting fossil fuels. It doesn't just cause methane emissions, it also emits carbon dioxide (CO2), sulfur dioxide (SO2), nitrogen oxides (NOx), particulate matter, mercury, and several other harmful pollutants and GHGs.[271]

The negative impacts of coal are numerous and extensive. Coal mining is energy intensive and labor intensive, and depending on the type of mine (surface or underground) it results in a great deal of environmental damage. Significant deforestation is a direct result of surface mining, as is mountaintop removal.[272] This in turn has drastic impacts on water resources through destruction and contamination.[273]

"In West Virginia, more than 300,000 acres of hardwood forests (half the size of Rhode Island) and 1,000 miles of streams have been destroyed" by mining.[274] In addition, underground mining is especially hazardous for workers, with many risking death and serious injury as well as chronic lung diseases and other health problems.

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[270] Food & Water Watch (FWW) is a nonprofit consumer advocacy organization headquartered in Washington, DC that runs cutting-edge campaigns to help ensure clean water and safe food. We work with various community outreach groups around the world to create an economically and environmentally viable future. We advocate for safe, wholesome food produced in a humane and sustainable manner, and public rather than private control of water resources, including oceans, rivers and groundwater.
[271] Union of Concerned Scientists. "Environmental impacts of coal power: air pollution." 2012 at 1.
[272] Union of Concerned Scientists. "Environmental impacts of coal power: air pollution." 2012 at 1.
[273] *Ibid at 1*.
[274] *Ibid at 1*.

The destruction doesn't stop there. Coal burning power plants emit so much carbon dioxide that they are the greatest source of CO2 emissions in the United States.[275] "In 2011, utility coal plants in the United States emitted a total of 1.7 billion tons of CO2."[276] Burning coal also causes smog, acid rain, and toxic air pollution.[277]

The concept of offsets from coalmine methane capture is so backwards that it's astonishing it is even under consideration. Not only will emissions continue at the source in California, but methane would be reduced while other GHGs are released from flaring the methane as well as from coal mining and coal burning power plants.

Allowing offsets from coalmine methane capture projects is just another pay to pollute scheme in which coalmines are *paid* money for capturing their methane emissions rather than let them escape into the atmosphere—the same coalmines that are responsible for emitting a host of other GHGs and are part of the larger process of burning coal for energy, which is the leading source of CO_2 emissions in the United States.

What's more is that through such an offset scheme, not only will an offset be sold to a company in California and a coalmine elsewhere will receive payment for the offset, but the coalmine being paid for the offset could also make additional profit from selling the captured methane for various end-use options outlined in the "Proposed Compliance Offset Protocol Mine Methane Capture Projects".[278]

The coalmines involved in mine methane capture projects would then receive a financial incentive from offsets, and possibly an additional incentive from selling their captured methane, further supporting the production of a fossil fuel that emits many serious GHGs in high amounts. This could even cause an increase in coal production.

> **Response:** The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-

[275] Union of Concerned Scientists. "Environmental impacts of coal power: air pollution." 2012 at 1.
[276] *Ibid at 1*.
[277] *Ibid at 1*.
[278] California Air Resources Board, California Environmental Protection Agency. "Proposed Compliance Offset Protocol Mine Methane Capture Projects." September 4, 2013 at 129

intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

The commenter's characterization of offsets as being counterproductive and not leading to real, additional, or permanent emission reductions will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

Comment: Of the eight options for destruction or end-use of captured methane, only two—open flare and enclosed flare—involve the actual destruction of methane. However, when methane is flared CO_2 is released into the atmosphere. There isn't much benefit from an offset, which is supposed to *remove* emissions in place of those not removed in California, that just replaces one type of emission (methane) with another or even many other types of emissions (carbon dioxide and the several other GHGs released from mining and burning coal).

The other six options for disposing of captured methane are all end-use options that involve using the captured methane to generate heat, electricity, other forms of power, and fuel. This means that coalmines stand to profit from both the offset and the potential sale of captured methane.

Response: CO_2, a greenhouse gas, is released when methane is destroyed via a flare or when combusted for productive utilization as allowed for in the MMC protocol. The concern over methane destruction resulting in the "replacement" of one type of greenhouse gas with another, however, is misplaced. Methane has a much higher global warming potential than carbon dioxide so the CO_2 emissions resulting from the destruction of methane still represent a reduction in the terms of the climate impact. Nonetheless, the MMC protocol takes into consideration the release of CO_2 from the destruction of methane, regardless of the destruction method or employed, and accounts for the impact of these emissions in the quantification methodologies. It is only the real, net emission reductions that are credited.

Captured mine methane can be sold and put to productive use. This economic reality is in no way altered by the MMC protocol since mine operators have the option to pursue such incentives with or without the existence of the offset protocol. Nonetheless, analysis showed that, aside from pipeline injection of mine methane extracted from methane drainage systems at active underground mines, the capture and destruction or utilization of mine methane is not common practice. By providing offset credits for emission reductions, the MMC protocol further incentivizes the capture and destruction of methane through a variety of means that are not deemed business-as-usual.

Comment: Furthermore, not only would mine methane offsets perpetuate hot spots in California by allowing pollution to continue at the source, they would also perpetuate hot-spots surrounding coalmines. Social, environmental, and health costs would continue where pollution occurs in California and at coalmine sites, all for the benefit of giving polluters in California another *option* in meeting their emissions reductions.

Do the supposed benefits of offsets, especially from coalmine methane capture projects, really justify the extensive costs that will burden not only the people of California but also communities across the United States?

Response: The limited use of offsets serves as an important cost-containment feature in the Cap-and-Trade Program. The environmental analysis prepared for the proposed MMC protocol concluded that its potential impacts to air quality would be less than significant due to the requirement that all projects comply with all applicable federal, state and local laws and regulations.

The Regulation requires GHG reductions on a statewide level, but does not stipulate specific improvements or compliance actions by individual regulated entities. Moreover, the Regulation does not obviate any existing local or regional air quality regulations or control programs related to the management of toxic air pollutants in California. In addition, the 2010 FED, to which the EA for the proposed amendments serves as an addendum, also identified ARB's commitment to an adaptive management approach to assess the effectiveness of the Regulation, and identify data trends that could indicate unanticipated or undesirable results. This monitoring and feedback approach lays out a framework to monitor the potential for adverse impacts that could result from action taken to comply with the Regulation.

GILLESPIE

Name: Sherri Gillespie
Affiliation: Private Individual
Written Testimony: 4/3/2014
15-Day Comment #: 56

Comment: This legislation must be stopped. Representatives of the mining and fossil fuel industries have contributed heavily to the protocol's drafting, dictating its terms.

State of California's Global Warming Solutions Act's (AB32) has the very strong potent potential to become a major driver of national and international coal mining and fossil fuel extraction in Indigenous Peoples' and non-Indigenous lands, as well as profiteering and increased environmental degradation. The Protocol is said to be about environmentally motivated methane capture and destruction for methane offsets. However it actually incentivizes and subsidizes the development of additional and potentially major coal mining and natural gas extraction operations, including flaring and burning, in existing and future in coal and trona mine areas. It represents not just business-as-usual for fossil fuel industries, but a future increase in fossil fuel extraction, with expansions in extent, production, output, and infrastructure including refineries and pipelines, together with permits to pollute more.

This hydraulic fracturing on steroids and must NOT pass.

> **Response:** Staff undertook an extensive public process, consistent the requirements of the Administrative Procedure Act, in the development of the MMC protocol. As in the past, staff started the protocol development process by evaluating existing voluntary and regulatory offset protocols and taking the best features through a public process to develop an ARB compliance offset protocol. Staff engaged with a diverse set of stakeholders and considered all comments made in order to put forward the best possible protocol that meets the rigorous standards of the Cap-and-Trade Regulation.
>
> Only projects located within the United States are eligible under the proposed MMC protocol. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-

intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

The protocol in no way impacts the permitting process applicable to the mining industry. Project developers must meet the regulatory compliance requirements set forth in section 95973(b) of the Cap-and-Trade Regulation and offset credits will not be issued if a project is not in compliance with regulatory requirements.

The protocol is unrelated to hydraulic fracturing aside from the explicit exclusion of mines that use CO2, steam, or any other fluid/gas to enhance mine methane drainage.

The commenter's claim that the MMC protocol represents business-as-usual will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

HAYES

Name: Linda Hayes
Affiliation: Private Individual
Written Testimony: 3/31/2014
15-Day Comment #: 9

Comment: I could hardly believe my eyes when I read that the State of California had gotten a mining executive to write a Mine Methane Protocol which does nothing but incentivize ongoing pollution from the coal mining industry. To my mind this is nothing less than criminal behavior. Please back out of this bad move and end the nonsense.

> **Response:** Contrary to the comment, the proposed MMC protocol was not written by a mining executive. Staff undertook an extensive public process, consistent the requirements of the Administrative Procedure Act, in the development of the MMC protocol. As in the past, staff started the protocol development process by evaluating existing voluntary and regulatory offset protocols and taking the best features through a public process to develop an ARB compliance offset protocol. Staff engaged with a diverse set of stakeholders and considered all comments made in order to put forward the best possible protocol that meets the rigorous standards of the Cap-and-Trade Regulation.
>
> Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

HO

Name: Kit Ho
Affiliation: Private Individual
Written Testimony: 4/3/2014
15-Day Comment #: 60

Comment: Extraction of fossil fuel like coal releases methane that requires the methane to be capture and burned. The methane is reduced to carbon dioxide. It causes environment degradation and is absolutely not a solution. Full force should be on the development of green energy like wind, solar, tidal wave, etc. giving the imminent ominous effect of global warning!

> **Response:** CO_2, a greenhouse gas, is released when methane is destroyed via a flare or when combusted for productive utilization as allowed for in the MMC protocol. Methane has a much higher global warming potential than carbon dioxide so the CO_2 emissions resulting from the destruction of methane still represent a reduction in the terms of the climate impact. Nonetheless, the MMC protocol takes into consideration the release of CO_2 from the destruction of methane, regardless of the destruction method or employed, and accounts for the impact of these emissions in the quantification methodologies. It is only the real, net emission reductions that are credited. An environmental analysis of the proposed MMC protocol determined that implementation of MMC projects would result in beneficial impacts to greenhouse gas emissions. The limited use of offsets serves an important role in the Cap-and-Trade Program, which reduces emissions and works in conjunction with other AB 32 measures to shift California's energy consumption toward renewable sources.

MAES

Name: Linda Maes
Affiliation: Private Individual
Written Testimony: 3/31/2014
15-Day Comment #: 29

Comment: This Mine Methane Capture Protocol will only encourage more fossil fuel extraction and burning, which exacerbates climate change, please don't do this!

> **Response:** Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

MARKS

Name: Luan Marks
Affiliation: Private Individual
Written Testimony: 4/4/2014
15-Day Comment #: 83

Comment: I hope you will reconsider and not pass the MMCP under the Cap and Trade Program.

Mine Methane Capture Protocol (MMCP) Comment Summary

- California's Air Resources Board's (ARB) proposed Mine Methane Capture Protocol has extremely strong potential to become a major driving force in subnational, national, and international fossil fuel extraction profiteering and increased environmental degradation.
- The MMCP purports to be about environmentally concerned methane capture and destruction, but it actually incentivizes and subsidizes the development of additional and potentially major natural gas extraction operations, including fracking and burning, in existing and future coal and trona mine areas.
- The MMCP represents a future increase in business as usual for the fossil fuel industries, with expansions in extent, production, output, and infrastructure, including refineries and pipelines, together with permission to pollute.
- The language of the MMCP permits open-ended possibilities in regard to location, extent of activities permitted, and environmental damage as the result of expansions and entrenchment of methane extraction operations and of potentially more extensive mining operations, in both abandoned and operating mines
- ARB staff have determined "potentially significant environmental impacts may be unavoidable.[279] Disclaimer was made that the environmental "analysis in these documents is necessarily programmatic in nature" because of site-specific or project-specific aspects that cannot be presently described.[280]
- Despite the fact that the MMCP is currently designated for U. S. mines, the overarching program is anticipated to be international in scope. California has already established major international links; ARB is also informed by the REDD Offset Working Group. With international expansion, some current constraints will fall away, including the domestic laws and regulations that are now major buffers for negative environmental impacts. This poses grave dangers in environmental and social justice arenas that are international in scope
- Flaring is not a sustainable or carbon negative use. While fracking is not mentioned as a capture technology, neither is it specifically prohibited.
- Focuses of coal extraction in the U. S. are federal and tribal lands. Because tribal lands are obvious sites for mine methane capture, tribes are at risk from the numerous environmental impacts of increased mining on their lands.

[279] http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isorappa.pdf, pdf 24, SR 20. This pdf includes both staff report (SR) and regulations (Reg), each with separate page numbers.
[280] http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13isor.pdf, 48

- The MMCP has built in major incentives for the fossil fuel industry to reap multitiered profits from a program of essentially deregulated resource extraction disguised as carbon abatement. It stands to increase global warming, rather than to mitigate it.

    Response: Only projects located within the United States are eligible under the proposed MMC protocol. The commenter's concern related to potential international ramifications are outside of the scope of applicability of the protocol and this rule-making.

    Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

    The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. The environmental analysis analyzed the potential environmental impacts of the proposed MMC protocol based on the expected compliance responses to the protocol, including the installation and operation of infrastructure used to capture, transport, treat and destroy mine methane. That analysis determined that implementation of MMC projects would result in beneficial impacts to greenhouse gas emissions, no impacts to public services and, less than significant impacts to aesthetics, agriculture and forest resources, air quality, energy demand, geology/soils and minerals, hazards/hazardous materials, hydrology/water quality, land use, noise, population and housing, recreation, transportation and traffic, and utilities and service systems. It further concluded that impacts to biological resources and cultural resources are potentially significant related to landscape disturbance required for construction of facilities and infrastructure. The EA identified recognized measures, including existing statutes and regulations and operating permit requirements designed to reduce this potentially significant impact, but the authority to determine project-level impacts and require project-level mitigation lies with the permitting agency for individual projects. ARB does not have the authority to require project-level mitigation. Further, the programmatic analysis in the EA does not allow project-specific details of mitigation, resulting in an inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts. Consequently, the EA takes a conservative approach in its post-mitigation significance conclusion and finds this impact potentially significant and unavoidable.

The programmatic level environmental analysis applies equally to potential projects on tribal and non-tribal lands. It is worth noting that the MMC protocol is not a compulsory regulation; rather the development of an MMC offset project is strictly a voluntary action. Moreover, no action that ARB takes in execution of California's Cap-and-Trade Program precludes action on greenhouse gas emissions by the federal government or jurisdictions outside of California. The protocol in no way impacts the permitting process applicable to the mining industry. Project developers must meet the regulatory compliance requirements set forth in section 95973(b) of the Cap-and-Trade Regulation and offset credits will not be issued if a project is not in compliance with regulatory requirements.

Staff disagrees with the commenter that the flaring of mine methane is not a carbon negative use. CO_2, a greenhouse gas, is released when methane is destroyed via a flare or when combusted for productive utilization as allowed for in the MMC protocol. Methane has a much higher global warming potential than carbon dioxide so the CO_2 emissions resulting from the destruction of methane still represent a reduction in the terms of the climate impact. Nonetheless, the MMC protocol takes into consideration the release of CO_2 from the destruction of methane, regardless of the destruction method or employed, and accounts for the impact of these emissions in the quantification methodologies. It is only the real, net emission reductions that are credited.

Finally, contrary to the comment, the protocol is not silent on hydraulic fracturing and in fact explicitly excludes mines that use CO2, steam, or any other fluid/gas to enhance mine methane drainage.

MARTINEZ

Name: John Martinez
Affiliation: Private Individual
Written Testimony: 4/2/2014
15-Day Comment #: 54

Comment: DON'T DO THIS!
The State of California's Global Warming Solutions Act's (AB32) proposed Mine Methane Capture Protocol (MMCP) [1] has extremely strong potential to become a major driver of national and international coal mining and fossil fuel extraction in Indigenous Peoples' and non-Indigenous lands, as well as profiteering and increased environmental degradation. The Protocol purports to be about the environmentally motivated capture and destruction of methane for offsets. However, it actually incentivizes and subsidizes the development of additional and potentially major coal mining and natural gas extraction operations, including flaring and burning, in existing and future coal and trona[2] mine areas. It represents not just business-as-usual for the fossil fuel industries, but a future increase in fossil fuel extraction, with expansions in extent, production, output, and infrastructure, including refineries and pipelines, together with permits to pollute even more.

NO TO A832!!!!!!!!!!!!!!!!!!!

> **Response:** Only projects located within the United States are eligible under the proposed MMC protocol. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm
>
> The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. The environmental analysis analyzed the potential environmental impacts of the proposed MMC protocol based on the expected compliance responses to the

protocol, including the installation and operation of infrastructure used to capture, transport, treat and destroy mine methane. That analysis determined that implementation of MMC projects would result in beneficial impacts to greenhouse gas emissions, no impacts to public services and, less than significant impacts to aesthetics, agriculture and forest resources, air quality, energy demand, geology/soils and minerals, hazards/hazardous materials, hydrology/water quality, land use, noise, population and housing, recreation, transportation and traffic, and utilities and service systems. It further concluded that impacts to biological resources and cultural resources are potentially significant related to landscape disturbance required for construction of facilities and infrastructure. The EA identified recognized measures, including existing statutes and regulations and operating permit requirements designed to reduce this potentially significant impact, but the authority to determine project-level impacts and require project-level mitigation lies with the permitting agency for individual projects. ARB does not have the authority to require project-level mitigation. Further, the programmatic analysis in the EA does not allow project-specific details of mitigation, resulting in an inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts. Consequently, the EA takes a conservative approach in its post-mitigation significance conclusion and finds this impact potentially significant and unavoidable.

The environmental analysis applies equally to potential projects on tribal and non-tribal lands. It is worth noting that the MMC protocol is not a compulsory regulation; rather the development of an MMC offset project is strictly a voluntary action. The protocol in no way impacts the permitting process applicable to the mining industry. Project developers must meet the regulatory compliance requirements set forth in section 95973(b) of the Cap-and-Trade Regulation and offset credits will not be issued if a project is not in compliance with regulatory requirements.

The commenter’s claim that the MMC protocol represents business-as-usual will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

MOTL

Name: Julie Motl
Affiliation: Private Individual
Written Testimony: 3/31/2014
15-Day Comment #: 11

Comment: This proposal, if passed, would be very detrimental to the state of California. It would only lead to more mining and more environmental destruction. I am concerned about natural gas mining in an already seismically active state. This is a terrible idea and should be banned! The profit gained by a few companies is not worth the potential damage to the citizens of California!

> **Response:** Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, ARB staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm
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> The commenter's expressed concern about natural gas mining in California, a seismically active state, is unfounded as California does not have active mines and only abandoned mines that could potential support MMC projects.

SKINNER

Name: Nancy Skinner
Affiliation: California State Assembly
Written Testimony: 10/17/2013
45-Day Comment #: 48

Comment: I am concerned about the draft Mine Methane Capture (MMC) carbon offset protocol, initiated under AB 32 and the Cap and Trade Program. The protocol, as written, will subsidize coal mining, likely for export. I urge you to postpone indefinitely the adoption of the Protocol scheduled for the October 24-25 Board meeting until a comprehensive plan for methane emissions reduction in California has been developed and adopted by the Board.

The MMC only counts emissions at the mining operation and not emissions associated with the use or transport of the product. With US exports of coal reaching their highest levels in two decades and doubling from 2006 to 2011, the MMC could actually increase carbon emissions. I am skeptical that the MMC "offset" can balance the additional emissions associated with moving coal thousands of miles over land and sea only to be burned where there are few environmental and air protections.

Global climate change is accelerating and the primary cause is the burning of fossil fuels. We cannot have a policy that directly incentivizes coal mining. The best way to reach our AB 32 goals is to keep coal in the ground. California has already taken steps to dis-incentivize the use of coal, but the draft MMC protocol undermines those efforts. (SKINNER)

> **Response:** The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at:
> http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

The comment about developing a comprehensive plan for reducing methane emissions in California is consistent with staff's recommendations in the proposed AB 32 Scoping Plan Update for addressing Short-Lived Climate Pollutants, which is currently open for public review and comment. This issue will be addressed more fully in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

STANFORD 4

Name: Aaron Strong
Affiliation: Stanford University
Oral Testimony: 10/24/2013
45-Day Comment #: 42

Comment: Having participated in this process actively and having seen the impressive work of the staff in preparing this protocol, I'm here today to say simply we aren't there yet. In my academic opinion, this protocol is not quite ready for adoption. My message put succinctly is this: More work needs to be done to assess the strong possibility of the protocol increasing emissions by making coal mining more profitable at some mines and truly conservative business as usual assumptions need to be made when setting eligibility criteria for projects at abandoned mines in order to avoid generating substantial non-additional credits.

> **Response:** The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets compare to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, and assessing whether or not the protocol would shift production between existing coal mines or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at:
> http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm
>
> The comments related to the eligibility criteria and additionality of abandoned underground mine methane recovery activities will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
> http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

STANFORD 5

Name:	Barbara Haya, Aaron Strong, Emily Grubert, and Deborah Sivas
Affiliation:	Stanford Law School
Written Testimony:	4/5/2014
15-Day Comment #:	127

Comment: Conflicts with implementation of greenhouse gas provisions under the Clean Air Act

A. At the October 2013 Board meeting, we and other stakeholders raised the concern that the proposed MMC Protocol would create incentives that conflict with implementation of greenhouse gas provisions under the federal Clean Air Act. Assuming states issuing Prevention of Significant Deterioration (PSD) permits follow Environmental Protection Agency (EPA) guidance, methane capture from drainage wells would be required at the large majority of permit-requiring mines. The Board's proposed MMC Protocol risks undercutting this EPA guidance by creating incentives for state permitting authorities to refrain from requiring methane capture so that mines within their jurisdictions would be eligible to participate in the Protocol and to receive payment for implementing MMC technologies. Board staff did not respond to this concern with revisions to the Protocol, nor with a written response refuting the concerns raised and the need for preventative measures.

We continue to strongly recommend that the capture of drainage methane from new mines and major mine expansions with releases large enough to require PSD permits should be ineligible for crediting in order to avoid undercutting implementation of Clean Air Act. It is important to note that the number of projects affected by this exclusion is a small minority of potential MMC projects and that the activities that would otherwise qualify this small number of potential MMC projects for credits should be legally required based on federal EPA guidance and precedent. Amending the eligibility section of the Protocol to exclude these projects is straightforward, is justified by the legal requirement test, and would avoid a significant tangible risk posed by the Protocol.

Again, we urge the Board to more carefully consider our detailed description of this concern and our recommendation in our comments to the Board from February 14, 2014, attached below, because Staff has never meaningfully addressed this concern.

February 14, 2014 (attached to written testimony submitted April 5, 2014)

(1) Drainage methane from new mines and major mine expansions with releases large enough to require Prevention of Significant Deterioration (PSD) permits should be ineligible for crediting in order to avoid conflicts with Clean Air Act implementation. So long as Environmental Protection Agency (EPA) guidance on PSD permitting for mines is followed by state permitting authorities requiring PSD permits, methane capture from

drainage wells would be required at the large majority of permit-requiring mines. Yet, the current draft MMC Protocol risks undercutting this EPA guidance on PSD permitting by creating incentives for state permitting authorities to refrain from requiring methane capture so that mines within their jurisdictions would be eligible to participate in the Protocol and to receive the large revenues expected from large MMC projects. To avoid this potential adverse effect and the resulting increases in emissions, we recommend that the Board amend the Protocol so that the destruction of methane from any new drainage wells at a mine requiring a PSD permit be ineligible for crediting under the Protocol. Restricting this eligibility eliminates the incentive for state permitting authorities to weaken PSD permit requirements for greenhouse gases (GHGs), and would avoid any conflict with EPA's regulation of greenhouse gases. Importantly, it would accomplish this without any disadvantage, since the only mines that would be prevented from participating in the Protocol due to this change would be mines that should be required to capture methane under the PSD permitting process.

We remain concerned about the eligibility of drainage methane capture from new active underground mines and major mine expansions with emissions releases large enough to trigger PSD permitting requirements. Under the Clean Air Act Tailoring Rule, PSD permits are required for emissions increases over 75,000 tCO2e/year for major modifications of existing mines or 100,000 tCO2e/year for new mines. In past comments we discussed a perverse incentive expected to result from allowing drainage methane from all new mines and major mine modifications to earn credits under the Protocol (see section 2 of our attached comment to the Board from 23 October 2013). As you know, PSD permitting requirements are determined on a case-by-case basis by state-level agencies. For each permit application, the state agency granting the permit must determine if methane capture is Best Available Control Technology (BACT) for reducing emissions for that particular mine and would therefore be required as a part of the construction permit. We discussed our concern that the Protocol may encourage state agencies to make weak BACT determinations so that mines in their state would be eligible under California's MMC Protocol to be paid to capture methane instead of being required to do so as a PSD permit condition. To the extent that BACT determinations are weakened in this way, not only would non-additional credits be generated from projects that would otherwise have been required by law, but these permits would also serve as precedent for other PSD applications in the state and via EPA's RACT/BACT/LAER Clearinghouse (RBLC) at the national level.[281] The precedent that could result from early and weak BACT rulings is of particular concern because state agencies commonly base new BACT determinations on past determinations at comparable facilities.[282] Given the substantial profits that could be earned from MMC at the gassiest mines (see Section 2 below), mine owners can be expected to watch state-level BACT determinations closely.

In these comments we stress and elaborate on three points. First, we emphasize that mines with emissions greater than 75,000 tons CO2e/y for existing sources that undertake major modifications and 100,000 tons CO2e/y for new sources are currently

[281] EPA RACT/BACT/LAER Clearinghouse. http://cfpub.epa.gov/RBLC/ (accessed 14 February 2014)
[282] *See*, RACT/BACT/LAER Clearinghouse, *at* http://cfpub.epa.gov/RBLC/ (accessed 14 February 2014)

required to apply for PSD permits under the Clean Air Act Tailoring Rule. EPA does not need to take further action for PSD permits to be legally required at gassy mines that might emit above the Tailoring Rule threshold.

Second, underground coal mines are currently being built and planned with emissions large enough to trigger PSD requirements. As noted in our October comments attached hereto, Walter Energy is developing a new mine in the gassy Blue Creek seam in Alabama.[283] An application to build Red Cliff Mine on Bureau of Land Management (BLM) land in Colorado has already drawn significant attention because of its expected methane emissions profile.[284] This list is not comprehensive but does indicate that new gassy mines are being developed. Both of these mines are expected to be gassy enough to require PSD permits. The Walter Blue Creek mine is similar to three existing mines that each liberate well over the 100,000 tonnes of CO2-equivalent per year (tCO2e/year) threshold over which a greenhouse gas PSD permit is required: in 2006, Blue Creek No. 7, No. 4, and No. 5 liberated 4.0, 3.0, and 1.2 million tonnes of CO2-equivalent per year (MTCO2e/year), respectively.[285] If built, Red Cliff Mine in Colorado is expected to liberate 3.1 MTCO2e/year.[286]

Third, we focus these comments on providing further evidence that methane destruction should be considered BACT at essentially all gassy mines expected to trigger PSD permitting requirements. This means that excluding these mines or mine expansions from participation in the Protocol avoids a potentially harmful perverse incentive that could weaken implementation of the Clean Air Act without restricting mines from participating in the Protocol that should not otherwise be required to capture drainage methane.

BACT determination

According to the Clean Air Act, Best Available Control Technology (BACT) is an emission limitation “based on the maximum degree of reduction of each pollutant subject to regulation . . . emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility. . .”[287]

When determining BACT, regulatory agencies place the responsibility for presenting and defending the technology selection on the applicant.[288] The BACT permit applicant

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[283] Walter Energy. Jim Walter Resources. http://walterenergy.com/operationscenter/jwr.html (accessed 11 February 2014).

[284] Earthjustice. “Pollution Giant: New Colorado Coal Mine.” http://earthjustice.org/features/pollutiongiant-new-colorado-coal-mine (accessed 11 February 2014).

[285] EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.

[286] Bureau of Land Management. Red Cliff Mine Environmental Impact Statement Table 4-6. http://www.blm.gov/co/st/en/BLM_Programs/land_use_planning/rmp/red_cliff_mine.html (accessed 11 February 2014).

[287] 42 U.S. Code § 7479

[288] Memo to Regional Administrators, I-X: Guidance for Determining BACT Under PSD at p4, http://www.epa.gov/region07/air/nsr/nsrmemos/bactupsd.pdf (accessed 11 February 2014).

typically undertakes the following five steps: "(1) identify available pollution control options; (2) eliminate the technically infeasible options; (3) rank the remaining control technologies by control effectiveness [at eliminating the pollutant in question]; (4) evaluate the most effective controls (considering energy, environmental, and economic impacts) and document the results; and (5) discuss the appropriate BACT selection with the permitting authority."[289] The EPA considers this five-step process very important to ensure proper compliance.[290]

If the applicant believes that the top pollution control option is inappropriate as BACT, the rationale for this finding must be fully documented for the public record.[291] Furthermore, the applicant should not argue that a control option is inappropriate for economic reasons unless the average cost-effectiveness of a BACT control option (calculated by dividing the annualized cost of its implementation by the pounds of pollutant reduced) is unduly burdensome compared to the cost effectiveness of similar projects for other sources in the national BACT clearinghouse.[292] Both EPA guidance documents and the Clean Air Act definition of BACT demonstrate an expectation that the selected BACT should be the most effective abatement technology that is both technically feasible and not unduly burdensome to the facility owner.

Mine methane capture at drainage wells should be considered BACT

EPA assessment[293] indicates that capture of drainage methane is available, technically feasible, environmentally effective, and cost effective, so it is reasonable to expect that it will be ruled BACT given the five step process outlined above.[294]

In late 2013, EPA published analysis of domestic, additional greenhouse gas abatement potential as part of a broader effort to characterize global abatement opportunities for non-CO2 GHG emissions.[295] Among other purposes, the analysis directly informs the United States' 2014 Climate Action Report to the United Nations Framework Convention on Climate Change,[296] indicating that the data constitute EPA's present understanding

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[289] New Source Review 90-Day Review Background Paper at p6, http://www.epa.gov/nsr/documents/nsrreview.pdf (accessed 11 February 2014).
[290] See many of the EPA comment letters on GHG permitting actions, e.g. Comments on Intent-to-Approve for Pacificorp Lake Side Power Plant, Block #2, http://www.epa.gov/nsr/ghgdocs/20110304pacificorplakeside.pdf (accessed 11 February 2014).
[291] Draft New Source Review Workshop Manual at B29, http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf (accessed 11 February 2014).
[292] "The presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category . . . Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if *any*, between the application of the control technology on those other sources and the particular source under review" (emphasis in the original) http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf at B29, B31
[293] Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).
[294] In a prototypical BACT example provided as Appendix G to (6), capture and destruction are demonstrated to be reasonable BACT options for a landfill, which shares many characteristics with gassy underground mines.
[295] Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. Table 1-5. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).
[296] 2014 CAR: United States Climate Action Plan. January 2014. http://www.state.gov/documents/organization/219038.pdf (accessed 13 February 2014).

of abatement potential. Coal mine methane control opportunities are identified in three categories: capture drainage methane for use; flare drainage methane; and destroy ventilation methane. In 2006, 12 out of 24 mines with drainage wells captured 80% to 100% of their drainage methane in order to sell that methane into a pipeline.[297] EPA's 2013 analysis of additional mitigation opportunities in coal mine methane control indicates such financial benefits are typical even for sites that are not currently capturing (since the analysis focuses on additional mitigation potential), with an average breakeven price for on site methane capture below \$0/tCO2e (these projects are income generating: average costs range from an average of -\$5/tCO2e to -\$1/tCO2e, depending on the particular form of use).[298]

In those cases where capture for use might not be cost effective for the mine owner, which we anticipate are unusual cases for mines that trigger PSD, EPA publications show that flaring is a cost effective abatement technology. The breakeven price for flaring at active underground coal mines is, on average, a little over \$6/tCO2e,[299] and flaring can be implemented at any mine with a drainage system, not just those near pipeline infrastructure or with on-site or nearby natural gas demand. In addition, EPA's marginal abatement analysis shows that about 75% of the total 2010 abatement potential – which comprises the maximum amount of abatement of mine methane at a facility level, including ventilation methane – is available at a breakeven carbon price of less than \$10/tCO2e. (The proportion is roughly the same for 2020 and 2030 marginal abatement opportunity.)[300] Thus, since both methane capture and destruction are technically feasible (the second BACT process criterion), effective at destroying methane (the third BACT process criterion), and not unduly burdensome compared to the cost effectiveness of similar projects for other sources (the fourth criterion), they can be assumed to be BACT. For example, see Table 1-7 in (15) to see that mitigation for landfill methane in covered landfills, which are similar to coal mines in many ways, is expected to cost between -\$2/tCO2e and \$10/tCO2e on average, with flares costing \$5-6/tCO2e (vs \$6.3/tCO2e for a mine). Notably, most capture-for-use applications for landfills are expected to have positive costs rather than generate revenues as they do for most coal mine applications. Methane flaring has been included as BACT in at least one PSD permit from the EPA RACT/BACT/LAER Clearinghouse.[301] The 2008 PSD permit for the expansion of the Rumke Sanitary Landfill in Ohio lists flaring as BACT.[302]

We note that an assumption that states with gassy coal mines will systematically rule extremely weakly on BACT for mine methane is not a valid reason to dismiss the concerns we raise in this section. First, controls are very often cost effective even

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[297] Environmental Protection Agency. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.
[298] Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. Table 1-5. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).
[299] Id.
[300] Environmental Protection Agency. Global Mitigation of Non-CO2 Greenhouse Gases. Data Annex: col_mac_output_epa.xlsx. December 2013. http://www.epa.gov/climatechange/EPAactivities/economics/nonco2mitigation.html (accessed 11 February 2014).
[301] EPA RACT/BACT/LAER Clearinghouse. http://cfpub.epa.gov/RBLC/ (accessed 14 February 2014)
[302] See RBLC ID #OH-0330

without regulation. We also call attention to actions like Colorado's 2013-2014 Oil and Gas Rulemaking Effort, under which Colorado is considering adopting EPA's full oil and gas New Source Performance Standards (NSPS) recommendations in addition to more stringent control measures for oil and gas.[303] Colorado is one of the states where new gassy underground mines are being planned. The state's ruling on oil and gas regulation demonstrates that Colorado cannot be dismissed as a lax BACT permitting authority.

We have shown here that drainage methane capture meets EPA BACT determination guidance for essentially all mines that might require PSD permits. We have also discussed briefly above and in more detail in earlier comments that there is a tangible and real risk that, as currently drafted, the Protocol could incentivize state agencies to accept weaker BACT determinations than they otherwise would have. We therefore recommend that the Board choose to exclude from crediting any drainage methane at a new mine or major mine modification that would require a PSD permit. Restricting this eligibility eliminates the incentive for state permitting authorities to weaken GHG PSD permit requirements, and would avoid any conflict with EPA's regulation of greenhouse gases. Importantly, it would accomplish this without any disadvantage, since the only mines that would be prevented from participating in the Protocol due to this change would be mines that should be required to capture methane under the PSD permitting process. We believe that there is a very strong case for eliminating eligibility for mines requiring PSD permits for crediting under the Protocol.

October 23, 2013 (attached to written testimony submitted April 5, 2014)

2. Conflicting incentives: Incentives created by the Protocol may weaken implementation of greenhouse gas regulations under the federal Clean Air Act. Incentives may also cause mine owners to flare methane that would have been injected into a pipeline in the absence of the Protocol. Both of these incentives only apply to new underground mines and underground mines that have undergone major modification.

Recommendation: The Protocol should either include refined eligibility criteria for projects at new underground mines and at underground mines that have undergone major modification to avoid these "perverse incentives," or new and majorly modified active underground mines should be excluded outright.

This modification is meant to avoid two potentially serious adverse effects of the current draft protocol that would increase emissions while also crediting non-additional (business-as- usual) reductions.

First, the Protocol may undermine effective implementation of greenhouse gas reductions under the federal Clean Air Act. Many new and major modifications to coal mines will need to receive Prevention of Significant Deterioration (PSD) permits for their

[303] Colorado Department of Public Health and Environment, Air Pollution Control Division. 2013-14 Oil and Gas Rulemaking Effort http://www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251635574914 (accessed 11 February 2014).

emissions of greenhouse gas pollutants. No such permits have yet been written for coal mines; and the terms of those permits are determined by state-level agencies on a mine-by-mine basis. This permitting process requires each state granting a permit to determine the Best Available Control Technology (BACT) for reducing emissions from the source. Under the current Protocol, a tangible “perverse” incentive therefore exists for state agencies to determine that the technologies that capture methane that are used for offset credits under the Protocol are not BACT. Such determination would allow mines within their borders to receive offsets payments to capture methane instead of being required to capture that methane without compensation under state implementation of the Clean Air Act. This risk is particularly high at the present time since no state has yet made a first BACT determination for greenhouse gas emissions reductions from a coal mine. A weak BACT determination for mines planning to sell offsets could have wider effect if weakened BACT standards set a precedent for other mines in the state. It is important to emphasize that, despite the fact that states have not yet begun issuing PSD permits and making BACT determinations, such permit applications and determinations for new mines and major modifications to existing mines are anticipated under the Clean Air Act. No additional rule promulgation or new legislation is required for this implementation to take place.

Due to the relatively slow rate at which new underground mines are built and expanded, it is expected that the majority of credits potentially generated under the active underground mine portion of the Protocol will be from existing mines. By incenting the development of MMC projects at existing mines the Protocol helps generate experience with MMC technologies that will encourage MMC to be considered BACT. This positive influence of the Protocol on policy implementation is a form of positive leakage – emissions reductions supported by the Protocol but not credited under the Protocol. Because of the relatively small proportion of new and expanding mines expected to participate in the Protocol, excluding these mines should not substantially weaken this positive leakage effect.

However, it is also important to note that coal mines still are being built and expanded. For example, new mining at Alabama’s Blue Creek seam, one of the country’s most gassy coal seams, is being planned,[304] and if built, would face both of the incentives described just above.

ARB staff response to these concerns: These issues were not addressed in the *Staff Report* nor by the Protocol.

Both of the risks we raise are tangible, substantial, and largely avoidable. The potential for offsets to “perversely” incent state regulators to refrain from adopting climate-friendly policies have long been discussed and documented. Christiana Figueres, who serves as Executive Secretary of the UN Framework of Climate Change, documented several instances of countries refraining from enacting climate-friendly policy to enable facilities

[304] http://walterenergy.com/operationscenter/jwr.html (accessed 17 October 2013)

within the country to pass the legal additionality test of the Kyoto Protocol's offsets program and to generate offsets credits.[305]

There is a simple, straight-forward solution to both of these risks. Both issues apply only to new underground mines and major modification to existing active underground mines. Both issues can be avoided by carefully defining project eligibility criteria to avoid crediting projects that could be considered BACT or mines where pipeline injection is feasible. Alternatively, these issues can be avoided by making drainage methane from new and majorly modified underground mines ineligible under the Protocol. Even if the Board decides to exclude these mines or mine expansions now, it can choose to include all or a subset of them in the future, after there is more clarity with regard to how BACT is determined for coal mines and if natural gas prices increase in a sustained manner.

We described our concerns in written comments submitted on July 1 and August 22, 2013 to the Board (attached hereto as appendixes).

August 22, 2013 (attached to written testimony submitted April 5, 2014)

1. We offer one suggested modification to the discussion draft protocol that we believe will simultaneously address two of the concerns we have raised. We suggest making projects that capture drainage methane from new underground mines and new major modifications to existing active underground mines ineligible under the Protocol. Doing so would avoid the Protocol's potential conflict with the Clean Air Act.

Projects that capture methane from drainage wells at new and major modifications to active underground coal mines should be considered ineligible under the Protocol

In our written comments emailed to you on July 1, and in our comments at the Offsets Workshop on August 19, we described two ways that the Protocol could result in an increase in emissions in addition to non-additional crediting.

First, the Protocol may undermine effective implementation of the Clean Air Act. Many new and major modifications to coal mines will need to receive Prevention of Significant Deterioration (PSD) permits for their emissions of greenhouse gas pollutants; no such permits have yet been written for coal mines; and the terms of those permits are determined by state-level agencies on a mine-by-mine basis. A tangible perverse incentive therefore exists for state agencies to determine that technologies which capture methane are not Best Available Control Technology (BACT) in order to allow mines within their borders to receive offsets payments to capture methane. This risk is particularly high at the present time before states have made their first BACT determinations for coal mines. A weak BACT determination for mines planning to sell offsets could have wider effect if weakened BACT standards are applied to other mines in the state. This potentially serious adverse consequence of the Protocol can be

[305] Figueres, Christiana. 2006. Sectoral CDM: Opening the CDM to the Yet Unrealized Goal of Sustainable Development. International Journal of Sustainable Development Law & Policy. 2(1)

avoided by excluding drainage methane at new underground mines and at existing active underground mines that have undergone new major modification as a source of eligible methane capture under the Protocol.

Both of these issues are described in detail in our written comment letter from July 1, a copy of which is attached hereto.

Both of these risks are tangible, substantial, and largely avoidable. Both apply directly to new underground mines and major modification to existing active underground mines and so can be avoided by making drainage methane from new and majorly modified underground mines ineligible under the Protocol. Even if the Board decides to exclude these mines or mine expansions now, it can choose to include them in the future, after there is more clarity with regard to how BACT is determined for coal mines and if natural gas prices increase in a sustained manner.

July 1, 2013 (attached to written testimony submitted April 5, 2014)

2. The Board should take proactive steps to prevent the Protocol from interfering with States' implementation of the Clean Air Act's New Source Review process and to avoid potential offset credit invalidations that may result from this interference.

Appendix B identifies two types of legal risks associated with the Protocol's relationship to the Clean Air Act. First, the existence of the Protocol creates an incentive for state permitting authorities to establish weaker standards for required Best Available Control Technology ("BACT") to control greenhouse gas emissions when they issue PSD permits for new mines or major modifications (expansions) of existing mines. In addition to directly compromising the implementation of the Clean Air Act and crediting projects that may otherwise have been legally required, the effects of these incentives may extend further if weakened control standards are applied to mines that do not implement offset projects. Second, if BACT determinations are made after offsets credits have been generated, there is a risk that those credits will be invalidated by a BACT determination that covers all or part of the technology implemented by the offsets project, triggering buyer liability. This, in turn, may trigger a wave of lawsuits among parties to the offsets transaction. In order to proactively avoid conflicts with the Clean Air Act and any resultant non-additional crediting or invalidation of credits, we recommend that the Board adopt scheduled updating procedures for MMC baselines, and that it exclude new or expanding mines from crediting. If the Board rejects this suggestion and elects to credit projects at these sites, it should, at minimum, authorize these projects only after any required PSD permitting process is complete and should set different, more conservative eligibility criteria for new and expanding mines to avoid influencing BACT determinations.

In conclusion, we emphasize that the risks associated with an MMC Protocol go beyond crediting non-additional projects and over-estimating reductions from individual projects. The potential for an MMC Protocol to cause a weakening of BACT standards, to incentivize flaring over productive methane use, and to increase profits from coal mining could lead to an increase in emissions substantially greater than the credits generated. Our analyses find that these effects may be substantial. The Board should take affirmative steps to avoid these effects in the design of the Protocol, through applying conservative project eligibility criteria, developing safeguards against conflicts with the Clean Air Act, and monitoring these effects as technologies and conditions change over time.

Appendix A of July 1, 2013 letter (attached to written testimony submitted April 5, 2014)

APPENDIX A
Project Eligibility Thresholds

At the second meeting of the Potential MMC Compliance Offset Protocol Expert Technical Working Group (hereafter, "the Working Group") on May 21, 2013, the Working Group discussed the potential use of thresholds for determining the eligibility of pipeline injection projects for offset crediting from mines with drainage systems. These thresholds were based on the goal of ensuring that non-additional projects are not eligible to generate offset credits.

While the Working Group's discussion was limited to thresholds for the eligibility of pipeline injection projects, we believe that the Board must consider the potential interaction of thresholds across multiple project types. Setting eligibility thresholds in a piecemeal manner for only a subset of project types is likely to generate non-additional credits.

We offer the following recommendations, which are each explained in detail below:

- If the Board develops thresholds for eligibility of pipeline injection projects in its draft Protocol, then the Board should also develop eligibility thresholds that are at least as stringent for all other project types[306] that destroy methane from drainage wells in order to avoid crediting non-additional projects. Based on our analysis, we believe that such thresholds are necessary for the Protocol to meet the requirement under AB 32 that offsets credits be additional.
- We urge the Board to consider defining eligibility thresholds for flaring of mine methane that are more strict than for productive uses of the methane (e.g., pipeline injection, on-site consumption) when those productive uses are economically feasible with carbon credits.

We support the Board in its endeavor to develop eligibility thresholds for pipeline injection that seek to ensure, to a very high level of confidence, that no non-additional mine methane capture projects will be eligible to generate offsets credits under the Protocol. Though our analysis here responds to a discussion about eligibility thresholds

[306] Other project types include flaring, other on-site destructive uses such as electricity generation, transportation fuel, heating fuel, thermal drying, or off-site destructive uses which do not involve sale into a natural gas pipeline network for distribution, such as the sale of methane for use as fuel at a nearby off-site facility.

for pipeline injection, we encourage the Board to apply similar analyses of the risk of crediting non-additional credits as the Board considers the eligibility of other project types that may be covered under this Protocol, including all methane destruction from active underground mine venting, and methane destruction projects at abandoned underground mines, and surface mines.

1. In order to avoid crediting non-additional projects, the Board should set eligibility thresholds that are at least as stringent as those set for pipeline injection for all other project types that use drainage-well methane.

At its May 21 meeting, the Working Group discussed previously assessed criteria for setting eligibility thresholds for pipeline injection. These options included differentiating by mining method, methane liberation rate, well source, gas composition (percentage methane), gas quality (concentration of contaminants in gas), well-life, and distance from pipeline. Much of our discussion centered on setting thresholds using gas composition metrics (i.e., the percentage of methane).

It is our understanding that the rationale for using eligibility thresholds for pipeline injection is to avoid crediting non-additional projects. Pipeline injection of methane is common practice at mines with drainage systems; a majority of mines with drainage systems currently inject methane into pipelines.[307] The threshold would thus be designed to establish eligibility for pipeline injection for a set of specific mine, well, or gas circumstances where injection *would not occur in the absence of the offset credit*, and thus, pipeline injection could be considered additional if the threshold criteria were met.

At its May 21st Working Group meeting, the Board did not discuss the application of eligibility thresholds for other methods of destroying methane, including flaring, or uses such as electricity generation and on-site heating. While pipeline injection of drained methane is common practice at a majority of mines with drainage systems in the United States, flaring is not currently in common practice,[308] nor are other uses of methane from drainage wells.[309] Since the rationale for the use of eligibility thresholds for pipeline injection is to assure that only additional projects are eligible for credits, it might seem straightforward to conclude that eligibility thresholds do not need to be applied to flaring or other destructive use project types. Because these activities are not currently common practice and are not economically profitable for most mines in the absence of offset credits, it could be assumed that these uses would be additional for any gas quality, well type, or other criteria, and thus there would be no reason to apply

[307] In its analysis of gassy mines with drainage systems, the EPA found that as of 2006, 12 of 23 mines with drainage systems injected the majority of their mine methane into pipelines, and an additional four mines used at least some portion of their mine methane. Data from: EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04- 003.

[308] According to EPA, as of 2006, no active coal mines in the United States were currently engaged in flaring mine methane. From: EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003.

[309] The use of methane for on-site power generation is common at mines in China, where projects have been developed under the Clean Development Mechanism. From: International Energy Agency. 2009. Methane in China: A Budding Asset with the Potential to Bloom: An Assessment of Technology, Policy and Financial Issues Relating to CMM in China, Based on Interviews Conducted at Coal Mines in Guizhou and Sichuan Provinces IEA Information Paper. Available at: http://www.iea.org/publications/freepublications/publication/name,15740,en.html

thresholds. However, *not setting thresholds for flaring and other destructive use projects strongly risks crediting non-additional projects.* The reason for this relates to the financial incentives presented to a project developer by the circumstance in which a threshold is applied *only* to pipeline injection project eligibility.

Consider the following example. If the Board were to develop an eligibility threshold for pipeline injection which requires that mine gas must be less than 80% methane[310] to be eligible for pipeline injection (because it is presumed that lower quality gas would not be sold into a pipeline without the added financial benefit from offsets sales), and if no threshold were applied for flaring projects (because it is assumed that flaring would not otherwise occur in the absence of the offset credit), then mine methane sources with 80% methane or greater would be eligible only for flaring projects. However, in this example, the pipeline injection eligibility threshold presumes that injecting gas of this quality or greater can be profitable *without* the offset credit. Flaring drainage-well gas could therefore be (1) eligible for crediting, but (2) non-additional. This would also be true for credited on-site use projects that destroy methane that exceeds the threshold: such projects would generate credits for the destruction of methane that would likely have occurred in the absence of the Protocol. As the example above illustrates, the Board risks crediting non-additional projects if it does not promulgate eligibility thresholds for *all* project types, including flaring and other on-site destructive uses.

In the scenario described above, we have shown that there is a risk of crediting non-additional projects in the absence of thresholds for projects other than pipeline injection. Below we show that the risk is strong, due to the financial incentives that a project developer would face. Whether a project developer would opt to profitably inject the greater-than-80% methane content gas or would opt to flare it would depend on the relative value of the profits received from offset credits that would be received for the flaring project and the value of the profits received from selling the gas into a pipeline.

In comments previously submitted to the Climate Action Reserve ("CAR") regarding its Coal Mine Methane Project Protocol,[311] members of our team provided an analysis of the relative revenues from natural gas sales to pipelines and the generation of offset credits in the context of CAR's Protocol's eligibility rules for drained methane, which permitted flaring but prohibited pipeline injection. Under plausible pricing scenarios for both offset credits and natural gas, project developers will expect greater economic returns from flaring methane for offset credits than they would for selling the same methane as natural gas on the wholesale market (see Figure 1). At a carbon price of \$15/tCO_2e and at natural gas prices up to\$4.50/mmbtu or less (for comparison, as of December 2012 natural gas wellhead prices were around \$3.35/mmbtu[312]), a project developer would opt to flare rather than profitably inject mine methane.

[310] We use this number as a simple illustrative example only, not as an intended suggestion of a threshold value, nor as a recommendation of gas-quality metric based thresholds. The analysis below would apply to any or all thresholds.
[311] Please see Appendix D.
[312] Energy Information Administration, Natural Gas Prices, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm. As of this writing, the most recent data for wellhead natural gas prices are from December 2012. Notably for our analysis, natural gas wellhead prices have remained under \$4.50/mmbtu since January 2011.

Figure 1: Economic Value of Carbon Offsets Compared to Sale of Natural Gas

		CO2 price ($/tCO2-eq.)					Value of natural gas sales
		5	15	25	50		
Natural gas price ($/mmBTU)	2.5	$ (40.58)	$ 141.92	$ 324.42	$ 780.67		$ 131.83
	3.5	$ (93.31)	$ 89.19	$ 271.69	$ 727.94		$ 184.56
	4.5	$ (146.05)	$ 36.45	$ 218.95	$ 675.20		$ 237.30
	5.5	$ (198.78)	$ (16.28)	$ 166.22	$ 622.47		$ 290.03
	6.5	$ (251.51)	$ (69.01)	$ 113.49	$ 569.74		$ 342.76
	7.5	$ (304.24)	$ (121.74)	$ 60.76	$ 517.01		$ 395.49
Value of carbon offsets		$ 91.25	$ 273.75	$ 456.25	$ 912.50		

Each cell in the main table of Figure 1 shows the difference between the value of the carbon offset derived from flaring methane and the value of selling that methane into a pipeline, for a range of natural gas prices and offset prices, per metric ton of CO_2e. Positive numbers are highlighted and indicate that the prices applicable in that cell, the carbon offset is more valuable than the direct sale of methane. Thus, under these conditions, a project developer will prefer to generate offset credits rather than sell captured methane into the pipeline network.[313]

In response to our earlier comments, CAR indicated that any project that has already been injecting into a pipeline would not be eligible for credits if it switched to flaring. The Board's Protocol could similarly exclude flaring from eligibility at mines (or wells) where injection is already occurring. This response has the effect of eliminating some, but not all risk. We emphasize that our concern is more general and applies equally to the financial incentives presented to a mine owner upon mine expansion, the development of a new underground mine, or the drilling of new gob wells to drain methane from an active mining face.

The fundamental problem is that an offset project developer that is eligible to receive offset credits for flaring drainage-well methane when pipeline injection is economically feasible but is not an eligible project type, will preferentially select flaring. This is because the value of the carbon offset is likely to be greater than the market value of natural gas (see Figure 1). If the Board were to set piecemeal eligibility thresholds for pipeline injection only, but not for flaring, the Board would create an incentive to flare gas that otherwise would have been injected into a pipeline, thus generating non-additional credits. We urge the Board to establish eligibility thresholds for flaring and other methane use projects that are at least as stringent as those established for pipeline injection.

We recognize that applying conservative eligibility criteria to flaring may miss opportunities to reduce emissions cost effectively through flaring mine methane. However, fromthe perspective of achieving California's emissions target, we view the

[313] The Table in Figure 1 and its description are copied from the previous comment letter submitted to the Climate Action Reserve. The full comment letter is included as Appendix D

risks associated with inducing the flaring of methane that would otherwise have been injected into a pipeline as far greater. As a compliance-grade offsets program, the credits generated must meet AB 32's requirement that all offset credits are additional. Thus, to avoid the strong risk of crediting non- additional activities outlined above, we urge the Board to adopt eligibility thresholds for all project types that use drainage well methane.

2. The Board should consider defining eligibility thresholds for flaring of mine methane that are more strict than for productive uses of the methane (e.g., pipeline injection, on-site consumption) when those productive uses are both additional and economically feasible with carbon credits to avoid incentivizing the unproductive use of this gas.

In Section 1, we urge the Board to set eligibility thresholds for flaring and on-site destructive use projects that are as least as stringent as those set for pipeline injection projects, in order to meet the statutory requirements of AB 32 that it avoid generating non-additional credits. In Section 2, we present an observation that refines our recommendation in Section 1. Setting identical eligibility threshold levels for flaring, other on-site destructive uses, and pipeline injection would address our primary concerns regarding crediting non-additional projects. However, the incentives resulting from setting such identical thresholds for all project types could still incentivize the flaring of methane that would otherwise have been put to productive use in the economy. Specifically, we note that such a Protocol could incentivize non-productive uses of methane (i.e., flaring) when productive uses (e.g., pipeline injection, electricity generation, vehicle gas) remain economically feasible with offset credits.

The decision to flare or to inject drainage methane that would otherwise have been vented would be determined by the relative profits from pipeline injection and flaring because the mine would receive offset credits from either project type. In order to build a pipeline project, the mine would have to construct pipeline infrastructure and potentially upgrade the quality of the gas by removing nitrogen or other contaminants. In contrast, flaring would likely require fewer up-front costs, but would not generate revenues from natural gas sales. When revenues generated from the sale of the gas into the pipeline do not make-up for the difference in relative costs of the two project types, under circumstances where identical thresholds are applied to injection and flaring projects, the project developer would prefer to flare the methane. This would be the case even if the operator could profitably inject the same natural resource into a pipeline network with offsets credits.

While there is no legal requirement for a Protocol to avoid creating such incentives under AB 32, as both project types would be additional in the above example, we bring this issue to the Board's attention because we believe that the Board may wish to draft a Protocol that avoids incentivizing the flaring of methane that could otherwise be put to productive use in the economy, for two reasons. First, the productive use of this methane would displace an equivalent amount of methane that would otherwise be consumed elsewhere within the pipeline, and thus the productive use would avoid emissions elsewhere in the economy. Secondly, setting thresholds so as not to incentivize flaring when productive-uses are feasible avoids having the Protocol encourage an activity which may be perceived as the waste of a valuable natural resource. For these reasons, we urge the Board to consider setting more stringent thresholds for flaring projects than for productive-use projects.

3. Recommendations

Based on our analysis, we recommend that, in order to minimize the risk of crediting non-additional emissions reductions, the Board should:

- Set eligibility thresholds for all projects types that use drainage-well methane (e.g., pipeline injection, flaring, electricity generation, and other on-site uses);
- Set eligibility thresholds for flaring and other destructive uses that are at least as stringent as the eligibility thresholds set for pipeline injection.

Further, we recommend that, in order to avoid incentivizing the flaring of methane that might otherwise have been put to productive use, the Board should:

- Set eligibility thresholds so that flaring projects are only eligible when productive uses (e.g., pipeline injection, on-site consumption) are unlikely to be effectively supported by offsets credits.

Finally, as also discussed in Appendix B, which addresses the need to regularly revisit the Protocol's approach to eligibility, given the evolution of regulation of mine methane emissions under the Clean Air Act, we urge the Board to consider establishing a timeline schedule for regularly revisiting eligibility threshold criteria for pipeline injection and other project types which destroy drainage-well methane. Given the relatively quick pace at which methane capture technologies are developing, revisiting thresholds criteria according a schedule established in the Protocol would help ensure that, in practice, eligibility thresholds are not inducing the crediting of non-additional projects.

Appendix B of July 1, 2013 letter (attached to written testimony submitted April 5, 2014)

APPENDIX B

Legal and Policy Interactions Between the MMC Protocol and the Clean Air Act's New Source Review Program for Greenhouse Gases

Two types of legal risk exist if the Protocol creates eligibility for projects at new mines or projects associated with mine expansions that increase emissions by 75,000 metric tons of carbon dioxide equivalent per year. First, the existence of the Protocol creates a perverse incentive for state permitting agencies to establish weaker standards than they otherwise might for required Best Available Control Technology ("BACT") to control emissions when the states issue Prevention of Significant Deterioration ("PSD") permits for new mines or major modifications of existing mines. In addition to potentially compromising the implementation of the Clean Air Act and risking crediting activities that would have occurred in the absence of the Protocol, this incentive could also further undermine the climate benefits of the Protocol if these same weakened permitting standards are applied to mines that do not implement offset projects.

Second, there is a risk that some BACT determinations could invalidate offset credits if the Board is not careful to credit only projects that have already fully complied with all New Source Review ("NSR") requirements. Many coal mines will be subject to the NSR permitting process upon expansion or when newly constructed. Mines that opened or made major modifications since 2011 may already be required to apply for PSD permits because of their greenhouse gas emissions ("GHG"), but none have yet gone through the application process.[314] Further, no state has yet defined GHG BACT for any such permit. There is, therefore, a risk that offsets may be invalidated if projects are certified for offsets before legally required BACT determinations have been made. For example, a BACT determination requiring methane mitigation measures for mines that are also generating offsets credits may, in some cases, invalidate those credits. But invalidation is no simple matter. Either litigation or individual mine regulation decisions could cause the invalidation of credits, but both of these processes can span months or years. In turn, invalidation and the resultant buyer liability may result in expensive and complex litigation for participants in the offsets transaction, including the Board.

Given these risks, the Board should take particular care to address any such potential conflicts now, at the outset of the development of the protocols. The Board's response to these risks should take a proactive approach above and beyond the level of concern expressed in the Climate Action Reserve draft protocol. We recommend here two measures that can help to mitigate these risks. First, the Board should include in the Protocol a schedule of time or event- based thresholds that will trigger a re-assessment of protocol baseline conditions. These periodic reassessments will allow for recalibration of the Protocol in response to BACT determinations. Second, the Board should consider excluding new mines and expanding mines engaged in major modifications from eligibility for offsets credits. This approach would eliminate the risk of conflict between offsets generated under the Protocol and Clean Air Act BACT requirements. If instead, the Board decides to allow offset projects at mines potentially subject to BACT, it should do so only after developing additionality analysis techniques specifically tailored to avoid conflict with BACT determinations. In addition, the Board should require that all MMC project developers attest in writing that the mine is in compliance with all PSD permitting requirements and certify any offsets generated at these sites only after the Board has independently assessed the baseline conditions and after any required BACT determinations have been made. In addition to these measures, the Board should establish monitoring and reporting requirements to ensure that any required BACT has been implemented and remains fully operational.

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[314] Each PSD permit requires a BACT determination. The U.S. Environmental Protection Agency, Clean Air Technology Center - RACT/BACT/LAER Clearinghouse, does not list any greenhouse gas BACT determinations for coal mines. See http://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=eg, accessed 27 July 2013

These informal comments update and incorporate by reference, as applicable to the Board's planned Protocol, comments previously submitted to the Climate Action Reserve ("CAR") regarding its Coal Mine Methane Project Protocol Version 2.0 (attached hereto as "Appendix D"). In the context of developing a compliance-grade offset protocol for California's carbon market, which may serve as a model for other offsets programs in North American and around the world, it is crucial that the protocol avoid legal and policy conflicts with federal law.

1. The Protocol's complex relationship with the Prevention of Significant Deterioration program under the Clean Air Act raises serious concerns about the ability of the Protocol to produce real and additional emission reductions.

As of 2011, large new and expanded coal mines are required to obtain PSD permits in order to comply with the Clean Air Act. New Source Review ("NSR") under the Clean Air Act applies to new or major modifications of mines.[315] The U.S. Environmental Protection Agency ("EPA"), through its Tailoring Rule, currently interprets the NSR provisions of the Clean Air Act to require the establishment of greenhouse gas emissions thresholds in PSD permits for the largest emitters.[316] Under the Tailoring Rule, new underground mines that emit at least 100,000 tons CO_2e per year and modifications to underground mines that increase the mine's emissions by at least 75,000 tons CO_2e per year are required to obtain a PSD permit.[317]

The PSD program puts substantially all of the permitting authority in the hands of state environmental agencies. PSD permits are generally issued by state agencies with delegated implementation responsibility.[318] In order to obtain a PSD permit, regulated sources must demonstrate to state regulators that they employ BACT to mitigate emissions. But what specifically constitutes BACT is determined by the state permitting agency on the basis of its assessment of technical and economic feasibility of available pollution reduction measures.[319] EPA has extremely limited authority to review these state agency findings unless they are unreasonable or unsupported by the evidentiary record. In short, state environmental agencies retain substantial discretionary authority to determine BACT in the context of PSD permits.[320]

A. The Protocol creates a tangible perverse incentive that encourages state-level regulators to make weak BACT determinations.

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[315] See generally 42 U.S.C. §§ 7470–79

[316] See 40 C.F.R. 52.21(b)(1)(i); . *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102, 134-35 (D.C. Cir. 2012), *reh'g en banc denied* (D.C. Cir. Dec. 20, 2012), *petition for cert. filed* (U.S. Apr. 17, 2013) (No. 12- 1253).

[317] 40 C.F.R. 52.21(b)(49)(b)(iii–v). While it is not certain how many new mines are likely to be permitted in coming years, if past trends are any indication, a substantial portion of any new mines are likely to meet or exceed this threshold. Of 75 reporting underground coal mining facilities, 33 emitted 75,000 tons or more CO_2e in that year. U.S. ENVIRONMENTAL PROTECTION AGENCY, 2011 GREENHOUSE GAS EMISSIONS FROM LARGE FACILITIES, *available at* http://ghgdata.epa.gov/ghgp/main.do.

[318] States that do not have an approved NSR State Implementation Plan or that implement a plan developed by the federal EPA rely to varying degrees upon the federal EPA to administer this portion of the Clean Air Act. All but five states, the District of Columbia, Puerto Rico, and the Virgin Islands have some version of a State Implementation Plan. See U.S. ENVIRONMENTAL PROTECTION AGENCY, NEW SOURCE REVIEW, Where You Live, *available at* http://www.epa.gov/NSR/where.html.

[319] See 42 U.S.C. § 7479(3). In some states the BACT determinations may be made by or implemented by the federal EPA, rather than the state permitting agency. See n. 4, *supra.*

[320] *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461 (2004). See also Appendix D, 2–3.

The availability of offset credits for methane emission reduction measures will increase political pressure on state regulators who make GHG BACT determinations to require minimal or no controls in order to retain legal additionality for MMC projects which benefit industry in their states. State agencies make determinations as to what constitutes GHG BACT on a case-by- case basis, taking into account available techniques and technologies for emissions control, as well as technical and economic considerations.[321] The measures a mine might employ in order to create offsets under the MMC protocol are among the measures an agency would consider for any mine requesting a PSD permit. This means that when a state makes a GHG BACT determination for an individual mine applying for a PSD permit, that state agency must decide whether the particular mine is required to capture and combust methane that would otherwise be released from the mine. If a mine must mitigate its methane emissions in order to comply with the terms of its PSD permit, this same mitigation could not generate offsets credits under the Protocol. But if a state does not require methane capture as BACT for the PSD permit, the mine may generate offsets credits from methane capture, if it chooses to do so. The state and the mine therefore have every incentive to find methane mitigation infeasible, even where the technology is readily available and not cost-prohibitive: both the mine operators and the state permitting agency would rather have a third party pay for the emissions reductions than to have them go uncompensated as a legal requirement. As explained in prior comments to CAR (see Appendix D), even the possibility or appearance of this perverse incentive can affect the integrity of the protocol. This concern is even more significant for California's efforts to establish a legally binding compliance mechanism.

CAR responded to this concern only with the assurance that it would "track developments under the CAA and BACT determinations made at the state level will inform updates to the protocol's additionality tests over time."[322] This approach is unsuitable for the Board's compliance-grade protocol, which, as a matter of law, may only sanction credits that are real and additional.

While all offset protocols present some risk of undermining other enforcement regimes, the risk under the MMC Protocol is tangible and immediate. Here, there is an existing federal law implemented by state agencies with considerable discretion as to the stringency of applied standards and a strong local constituency with a financial stake in the determinations. Because the perverse incentive would affect agencies in other states, California's actions could create serious consequences for the implementation of the Clean Air Act that neither California nor EPA, given its limited authority to review state BACT determinations, could effectively remedy.[323]

If the Board proceeds with a protocol that does not address the PSD conflicts that we identify here, weak GHG BACT determinations may occur in key states that could

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[321] See 42 U.S.C. § 7479(3).
[322] Climate Action Reserve, Summary of Comments and Responses – Coal Mine Methane Project Protocol Version 2.0, 3.4.4.1 (p. 3), http://www.climateactionreserve.org/wp-content/uploads/2009/10/Summary_of_Comments_and_Responses_CMM_Project_Protocol_V2.0.pdf
[323] *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461 (2004).

thereby lock- in a deflated legal baseline for credits under the Protocol and hinder stricter GHG BACT determinations more broadly. We emphasize that this outcome would affect methane emissions at both mines where MMC Protocol projects are implemented and those where they are not.

B. BACT determinations that require methane reductions may invalidate issued offsets, triggering buyer liability and litigation risks.

If the Board were to credit reductions from mine methane control measures, and a subsequent BACT determination includes methane control measures, those credits could be subject to invalidation. When a permitting agency issues a PSD permit, it is required to consider both the technical and economic availability of emissions reductions measures. If, in making this determination, a state reaches a BACT determination that imposes strong GHG limits – rather than succumbing to the incentive to weaken permitting standards as described in section A above – certain otherwise eligible emissions reductions may no longer be creditable under the Protocol. If a PSD permit finds that the project activities constitute BACT, and are therefore legally required, the project could no longer be considered legally additional under the Protocol, and buyer liability would be triggered. In this situation, we are concerned that the triggering of buyer liability might affect investor confidence in this project type and/or the ARB offsets program more generally and that the Board could face protracted litigation.

At particular risk of invalidation are offsets issued for the term between the effective date of the BACT determination (which could precede the date the permit is issued if the mine has failed to apply for the permit in a timely manner) and the end of the reporting period during which the effective date occurs. Depending on the circumstances of the PSD program, the Board's determination may be more complicated, and even reaching a clear understanding of which credits are valid and invalid may be extremely difficult to establish.

Furthermore, in a situation where a state BACT determination invalidates some or all of a project's credits under the Protocol, it will not necessarily be clear at what point those legal obligations invalidated the credits. For example, if a mine did not apply for a PSD permit, but a court determined that one was needed, does a subsequent BACT determination that sets a performance standard above the MMC invalidate all credits the project generated, or just the ones issued after the court decision? This complexity increases the uncertainty created by the interaction between the Clean Air Act and the MMC protocol.

2. The Board Should Adopt Measures to Affirmatively Address Conflicts with the Clean Air Act

In order to reduce the risks described above, the Board should adopt two measures that would serve to address both the regulatory incentive problem and any resultant uncertainty around potential invalidation. First, the Board should establish a schedule of dates and/or triggering events for re-evaluation of the legal additionality baseline under the protocol. The schedule should anticipate ongoing GHG BACT determinations, changing market conditions, and recent technical developments; it should also indicate the Board's willingness to examine differences in GHG BACT determinations among different state permitting agencies for similar mines in evaluating additionality under the MMC protocol.

Second, the Board should adopt separate offsets eligibility criteria for projects at existing mines and projects at mines that may arguably be considered new or major modifications for the purposes of NSR. In these separate procedures for new or expanded mines, MMC projects at new mines or new emissions associated with major expansions of existing mines should remain ineligible for crediting until there is greater clarity about how NSR will be applied to mines, including specifically how BACT for GHG emissions will be determined. At a minimum, if the Board does consider crediting MMC projects at new or newly expanded mines, the Board should set more conservative eligibility criteria for these mines to avoid conflict with BACT determinations. In addition, the Board should require project developers to attest in writing that the mine is in compliance with all PSD permitting requirements, and that any even arguably needed BACT determinations are finalized prior to establishing the baseline emissions for the project. These latter requirements, however, only address the risk of invalidation and would not avoid regulatory incentives to weaken GHG BACT determinations.

A. The Board should adopt scheduled updating procedures to MMC baselines.

As we suggested to CAR, by establishing a clear schedule of dates and/or triggering events for re-evaluating the protocol legal and technical baselines, the Board will reduce the strength of perverse incentives to create long-term distortions in both the offsets market and Clean Air Act implementation. This measure will send a clear signal that, notwithstanding any attempts to manipulate additionality determination through artificially weak GHG BACT determinations, the Board will not allow these determinations to set an additionality baseline either unilaterally or for an extended and indefinite time. A triggering event could be a particular event, such as the issuance of the fifth PSD permit for mine methane emissions, or a certain level of market penetration of a methane reduction technology. Alternatively, the Board could use a time horizon. Moreover, unless the Board plans to monitor every relevant GHG BACT determination on its own, we suggest that it explicitly invite interested parties to identify relevant problems as the PSD program gains experience under the Tailoring Rule, reviewing the legal additionality standard at its discretion.

One of the principal benefits of this adaptive management feature would be that regulated entities and state regulators outside of California would have clear guidance regarding the conditions under which the baselines will be adjusted. As a result, market participants could invest with greater certainty, and the temptation for state regulators to game the GHG BACT process would be reduced. While this measure would not eliminate risk of states making GHG BACT determinations that are one generation behind the Protocol's latest baseline adjustment, this form of adaptive management would limit the long-term lock-in of weak GHG BACT in states where financial incentives are oriented towards maximizing revenues from offsets for coal and other mines. It would also help to maintain the integrity of the protocol by reducing the perception that the protocol creates perverse incentives that might undermine the environmental benefits of mine methane reduction offsets.

B. The Board should refrain from crediting projects at arguably new mines or major modifications of existing mines. If it chooses to credit projects at these sites, it should do so only after ensuring that credited offsets will not be retroactively invalidated. Such projects should be required to meet more conservative eligibility criteria that avoid conflict with GHG BACT determinations.

Given the very real influence that California's MMC Protocol may have on GHG BACT determinations for coal mines, the Board should avoid possible conflicts with the Clean Air Act by refraining from crediting projects at mines that are even arguably new or major modifications of existing mines for the purposes of NSR until several PSD permits have been issued in multiple states. Once it is clearer how states will make GHG BACT determinations for coal mines, the Board will be better able to identify eligibility criteria that would avoid crediting projects which might also have been considered GHG BACT in the absence of the Protocol.

If the Board rejects this position and instead elects to approve any projects from new mines or mine modifications large enough to raise the possibility that a PSD permit may be required, it should be particularly conservative in determining eligibility criteria. Eligibility criteria should be established for these mines that conservatively avoids crediting any activity that may be considered BACT. In any event, no credits should be issued for these projects until all arguably required PSD permitting procedures are complete and any measures required by these permits are implemented and verified. To operationalize this requirement, MMC Protocol project developers should be required to attest to such completion as a part of their project registration.

Even after there is greater clarity about how GHG BACT is being applied to coal mines, the Board should still maintain separate eligibility criteria for projects at mines that may arguably be subject to NSR. By adopting separate baseline determination procedures for projects at new mines and for major modifications, the Board can assess the GHG BACT determination made for each mine and determine whether the mandated controls reflect an additionality threshold consistent with the Board's assessment of the state of the industry. In this way, the Board can simultaneously eliminate the risk that a particular GHG BACT determination might invalidate existing offsets and establish a baseline that will counteract the effects of any artificially weakened GHG BACT determinations that might arise in response to the protocol.

Appendix D of July 1, 2013 letter (attached to written testimony submitted April 5, 2014) commenting on the Climate Action Reserve's Coal Mine Methane Project Protocol Version 2.0

APPENDIX D

The Environmental Law Clinic, part of the Mills Legal Clinic at Stanford Law School, submits these comments to the Climate Action Reserve (the "Reserve") on behalf of Dr. Michael Wara, Associate Professor at Stanford Law School, regarding the Coal Mine Methane Project Protocol, Version 2.0 for Public Comment (the "Protocol").

We appreciate the opportunity to share our perspective on the updated Protocol, and hope our views will contribute to the development of high-quality offset protocols. We would also like to acknowledge the detailed work that has gone into preparing the Protocol by both CAR Staff and the CMM working group. The result is both thorough and fully transparent.

Although the Protocol is generally robust in our opinion, we hope to (1) raise some potential concerns associated with the interaction between the Protocol and the Clean Air Act, and (2) discuss our reservations about the performance standard test with respect to on-site use of methane.

1. Regulatory Conflicts. The Protocol has the potential to undermine implementation of Clean Air Act regulations for coal mine methane emissions. This issue requires high-level policy discussion that is not part of the Protocol documentation to date.

As a preliminary matter, we want to highlight a potential conflict the Protocol might create with implementation of stationary source controls on greenhouse gas ("GHG") emissions under the Clean Air Act ("CAA"). We believe this is an issue the Reserve should consider in more detail, especially if the Reserve intends to submit the Protocol to the California Air Resources Board for approval as a compliance-grade protocol for the California carbon market.

As the Protocol notes, EPA has begun regulating GHG emissions from stationary sources under the CAA. Under the legal requirements test for the Protocol, any EPA or CAA requirements for controlling methane would immediately become a part of a project's baseline calculation, and thus not eligible for offset credits.[324] With no existing regulations that force destruction or capture of methane (outside of mine safety rules), the Protocol suggests that the possibility of future regulation is simply one risk factor that projects will have to consider.

This view oversimplifies the applicable Clean Air Act provisions and neglects several key issues, which we discuss below. These issues have potentially significant implications for this Protocol or any other involving a large stationary source of GHGs, both for the Reserve and the California Air Resources Board. As a result, we believe further high-level discussion is required to ensure that the Protocol does not create actual unintended conflicts—or even the appearance of unintended conflicts—with EPA or the Clean Air Act.

[324] Protocol § 3.4.1.1.

Indeed, these sorts of interactions are increasingly likely in a fragmented climate policy landscape, and the Reserve is well positioned to be a leader in developing carefully considered climate strategies that minimize potential conflicts with other regulatory systems.

1.1. Because BACT determinations are made by state permitting agencies, the Protocol could undermine effective implementation of CAA requirements by creating political pressure to weaken BACT standards outside of California.

We are concerned that the Protocol has the potential to undermine or weaken implementation of CAA regulations by creating an incentive for state regulators to weaken BACT determinations for controlling coal mine methane emissions. EPA's recent Tailoring Rule requires certain new facilities or major modifications of existing facilities to obtain a Prevention of Significant Deterioration ("PSD") permit, for which state permitting agencies must determine and apply the best available control technology ("BACT").[325] In particular, major modifications of existing facilities, including coal mines, that result in increased emissions of at least 75,000 tons per year of CO2e are required to obtain PSD permits.[326]

Although EPA sets the basic contours of the PSD program, application of BACT is left to the states. In *ADEC v. EPA*, the Supreme Court decided that EPA's ability to challenge state BACT determinations is limited to when the state's determination is "not based on a reasoned analysis."[327] This decision gives state permitting agencies wide discretion in determining BACT, subject only to procedural review from EPA. Because states have effective control over BACT determination, those with coal mine projects seeking offset credits under this Protocol will face additional political pressure to set BACT at levels that create headroom for offset creation. Strict BACT determinations would reduce or eliminate income from offsets, and thus state regulators could face pressure from offset project owners and developers to keep BACT determinations low. Further, state regulators will be aware, or will be made aware by the regulated sources, that in the event they set BACT less stringently, emissions reductions will nevertheless occur because of offsets. Under the *ADEC* standard, EPA would have limited options to challenge any state determinations it perceived as weak. Should this situation arise, the effect of the Protocol would be to unintentionally weaken or undermine implementation of the Clean Air Act.[328]

Even if the income generated from Protocol projects has no influence on state regulators' BACT determinations, the Protocol could nevertheless create the appearance of influence. This might occur if states make widely divergent BACT determinations. If some states apply strict BACT determinations, while others apply

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[325] *See generally* Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31514 (June 3, 2010).
[326] *Id.* at 31516.
[327] *Alaska Dep't Envtl. Conservation v. Envtl. Prot. Agency*, 540 U.S. 461, 490 (2004) (citations omitted).
[328] We note that exactly this situation has allegedly occurred under the CDM, where national regulators weakened standards for large landfills in order to create headroom for the creation of CERs under CDM landfill methane protocols. *See* Christiana Figueres, Sectoral CDM: Opening the CDM to the yet Unrealized Goal of Sustainable Development, 2 MCGILL INT. JOURNAL OF SUSTAINABLE DEVELOPMENT LAW AND POLICY 1, 12 (2006).

weak determinations, the Protocol could be seen as subsidizing the disparate outcome, as Protocol projects would presumably cluster in states with the most lax permitting agencies. It may be possible to create a "race to the top" in the Protocol's legal requirements test by adopting a threshold from the strictest BACT determinations. But without knowing how states will make BACT determinations, and in what form, it is difficult to imagine writing such a provision into the Protocol at this stage of the CAA regulations.

While these concerns are only hypothetical at this point, we believe the Reserve should have a broader discussion about the unintended consequences its offsets protocols may have in sectors where impending state or federal regulations complicate the application of offset protocol design. We also believe that CAR should develop a plan, set down explicitly in the protocol, to address these concerns once we know more about how states will proceed with BACT determinations for CMM. We would propose that once 5 BACT determinations have been concluded, CAR review them and consider revising Section 3 of the Protocol as appropriate.

1.2. Determining what constitutes a "major modification" of an existing coal mine under EPA's Tailoring Rule is an open legal question. The Protocol does not offer any guidance on how project developers would bear the risks associated with litigation on this issue.

The Protocol does not sufficiently anticipate the possibility that PSD permits might be required for existing coal mines, even without new regulations from EPA. To the best of our knowledge, there are no cases or regulations clarifying what constitutes a "major modification" of an existing coal mine for the purposes of the CAA. If certain common activities—for example, beginning work on a new section of a coal seam within an existing large mine—are determined to be major modifications, then the Tailoring Rule would apply, and PSD permits would be required for mines creating new emissions above the established threshold.

The Protocol would benefit from a fuller discussion of how these risks would be distributed, especially with the prospect of lengthy litigation or subsequent regulatory developments. We have several questions about what the timing of these kinds of changes would imply for calculating additionality under the Protocol:

- Does the Protocol's legal requirements test apply at the time the legal requirement is identified (*i.e.*, when a court or administrative agency finds that a PSD permit is required) or when the actual legal requirement is specified (*i.e.*, when a state regulator identifies BACT for a particular mine project)?
- If litigation produces a determination that a major modification took place, does the Protocol's legal requirements test adopt BACT requirements retroactively, from the date of the legal decision, or from the date of the subsequent issuance of a permit? Does it matter whether the question litigated was a new issue that was fairly disputed by both sides?
- If litigation or a new regulation defines a threshold for major modifications, must all applicable projects immediately adopt BACT requirements as part of the legal

requirements test, or are those requirements not binding for the purposes of the Protocol during a legally valid gap (*e.g.*, a temporary window for securing permits)?

1.3. Air pollution from coal mines is not yet subject to new source performance standards under Section 111 of the CAA, the future implementation of which would set a floor for state determination of BACT for PSD permits. The Reserve should monitor developments on this front.

EPA has not yet exercised its authority to create performance standards for coal mine methane emissions controls under Section 111 of the CAA, but faces pressure to do so. These performance standards would apply to all new and existing coal mines. In June 2010, a group of environmental organizations petitioned EPA to list coal mines as a category of stationary sources subject to performance standards for GHGs, including coal mine methane as a particular source of concern. EPA has not acted on this petition. As a result, the environmental groups sued, seeking to compel EPA to grant or deny the petition.[329]

The outcome of this ongoing litigation matters, as EPA's performance standard authority extends to both new and existing emissions sources.[330] Moreover, state determinations of BACT cannot allow emissions higher than levels determined under Section 111 of the CAA.[331] That is, state BACT determinations are constrained to be no weaker than a performance standard set by EPA under its § 111 authority. Therefore, we believe the Reserve should pay close attention to this issue going forward, as it may either exacerbate or relieve some of the other CAA interactions described above.

If and when EPA sets a § 111 performance standard, it will act to significantly shift the baseline emissions for all participating or potential projects under the CMM protocol. The concerns raised above in section 1.2 also apply here. Furthermore, the Reserve should plan on this performance standard being subject to lengthy litigation. How will project registrations be treated and offsets generated by registered projects during this period of uncertainty be credited?

2. Additionality. The Protocol's Performance Standard Test does not adequately address the possibility that drainage systems have the economically viable option to inject methane into a commercial pipeline, but choose instead to use or flare methane onsite.

We are concerned that some offset projects may be able to switch back and forth between earning offsets under this Protocol and selling methane into a pipeline network. If permitted, this temporal "stacking" would undermine the additionality of the Protocol, and runs counter to principles articulated in other Reserve protocols.[332]

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[329] *WildEearth Guardians, et al., v. U.S. Envtl. Prot. Agency and Lisa P. Jackson*, No. 1:11-cv-02064-RJL (D.D.C.) (complaint filed Nov. 17, 2011).

[330] 42 U.S.C. § 7411(b) (new sources); 42 U.S.C. § 7411(d) (existing sources); *see also* Georgetown Climate Center, Issue Brief: EPA's Forthcoming Performance Standards for Regualting Greenhouse Gas Pollution from Power Plants (Clean Air Act Section 111).

[331] 42 U.S.C. § 7479(3).

[332] *See, e.g.,* Climate Action Reserve, Rice Cultivation Project Protocol, Version 1.0 § 3.5.3 (prohibiting

Our concerns arise because the Protocol's eligibility rules allow a drainage system to qualify for offsets by flaring or otherwise using methane, even if selling methane to a pipeline is commercially viable. In other words, the eligibility rules do not include an analysis of the economic viability of injecting methane into a pipeline network. Drainage projects pass the performance standard test simply if they destroy methane "through any end-use management option other than injection into a natural gas pipeline."[333] Remaining eligibility rules require only that that project start dates be no more than three months after the drainage system begins commencing destruction of methane.[334]

Under these rules, a drainage system that injects methane into a pipeline would not appear to qualify for offsets if the project developer decides to build a flare or other end-use management application to replace pipeline exports. Assuming the switch happens after three months of injection, it would appear to violate the eligibility rule on timing. However, the eligibility rules allow for multiple drainage systems to exist at a single coal mine, raising the prospect that as new boreholes are drilled as the mine face advances, the mine operator could elect to either create offsets by flaring or sell pipeline gas from new drainage wells.

We would appreciate the Reserve confirming this matter, and suggest further that there is no valid reason to view a project at a mine that has ever injected gas into a pipeline as additional.

Unfortunately, nothing in the protocol rules precludes the reverse ordering: a project that could economically inject methane into a pipeline might choose instead to pursue an on-site activity and earn offset credits. So long as the drainage system does not inject methane into a pipeline network, it is assumed to be additional under the performance standard test.

That assumption is flawed, however, under a variety of plausible economic conditions. Project developers might instead see the Protocol rule structure as giving them the chance to bet long on carbon prices, with a backstop option to sell methane into a pipeline network if carbon prices do not rise as expected. Indeed, the rational project developer considering pipeline sales would be wise to consider whether or not a carbon offset provides a higher value hedge against low gas prices, as Figure 1 demonstrates.

Figure 1: Value of Carbon Offset Minus Value of Pipeline Sales (\$ per metric ton of CH_4) **[335]**

stacking of ecosystem service payment systems in addition to earning carbon offsets for the same mitigation activities).

[333] Protocol § 3.4.2 (based on the analysis in Protocol Appendix A).

[334] *Id.* § 3.2.

[335] Source: authors' calculations using flaring as an example offset project. Assumptions: 52.73 mmBTU per tCH4 and 18.25 tCO2e avoided per tCH4 destroyed (using GWP and "r" values from Protocol equations 5.5 and 5.9, respectively); prices as shown in chart.

		CO2 price ($/tCO2-eq.)				Value of natural gas sales
		5	15	25	50	
Natural gas price ($/mmBTU)	2.5	$ (40.58)	$ 141.92	$ 324.42	$ 780.67	$ 131.83
	3.5	$ (93.31)	$ 89.19	$ 271.69	$ 727.94	$ 184.56
	4.5	$ (146.05)	$ 36.45	$ 218.95	$ 675.20	$ 237.30
	5.5	$ (198.78)	$ (16.28)	$ 166.22	$ 622.47	$ 290.03
	6.5	$ (251.51)	$ (69.01)	$ 113.49	$ 569.74	$ 342.76
	7.5	$ (304.24)	$ (121.74)	$ 60.76	$ 517.01	$ 395.49
Value of carbon offsets		$ 91.25	$ 273.75	$ 456.25	$ 912.50	

Each cell in the main table of Figure 1 shows the difference between the value of the carbon offset derived from flaring methane and the value of selling that methane into a pipeline, for a range of natural gas and carbon prices, per metric ton of CH_4. Positive numbers are highlighted and indicate that for the prices applicable in that cell, the carbon offset is more valuable than the direct sale of methane. Thus, under these conditions, a project developer will prefer to generate offset credits rather than sell captured methane into the pipeline network.

For context, the U.S. Energy Information Administration reports that average wellhead natural gas prices in December 2011 were $3.06 per mmBTU; prices since 2000 have generally ranged from $2.5 to $7.5 per mmBTU, with a few higher spikes.[336] A carbon price of $5/tCO2e is a reasonable approximation of the voluntary carbon market, whereas estimates of California's compliance costs are bounded by the remaining prices shown here.

We note that at current forward delivery prices for CCAs ($14.80 for Dec 2013 delivery),[337] current compliance grade carbon prices would tend to push a coal mine to orchestrate a switch to selling offsets from selling pipeline gas.

The net effect of these incentives is to undermine a key assumption in the Protocol's additionality calculations. By defining the performance standard test for drainage systems as any control technology that does not involve pipeline injection, the Protocol implies that pipeline sales are already economically viable and that all projects not injecting into pipelines do not find it viable to do so.[338] The calculations presented in

[336] Energy Information Adminstration, U.S. Natural Gas Wellhead Price (March 25, 2012), available at: http://www.eia.gov/dnav/ng/hist/n9190us3M.htm. EIA reports December 2011 prices were $3.14 per thousand cubic feet of natural gas. At 1.025 mmBTU per thousand cubic feet of natural gas, this price is equivalent to $3.06 per mmBTU.

[337] *See* PointCarbon, Carbon Markets North America, 23 March 2012, *at* 2.

[338] Protocol Appendix A draws erroneous conclusions to support the proposition that drainage systems using non-pipeline control technologies are always additional. Specifically, Appendix A concludes that the paucity of non-pipteline control technologies reflects their being uneconomic generally, rather than being less economic than pipeline injection. According to Appendix A, only four of twelve drainage systems that do not have a pipeline interconnection employ an alternative mitigation technology. Of these four projects, two are at mines that also have pipeline injections; the analysis excludes these two projects, and focuses only on the two remaining projects that use methane at mines where no pipeline interconnection is present.
On this basis, Appendix A concludes that "on-site end use projects are uncommon even at mines that do not sell their [methane] to pipelines . . . this finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects." To the extent two drainage projects permit any valid basis for establishing *ex ante* additionality criteria, a more appropriate conclusion would be that the data cannot rule out the alternative hypothesis that pipeline injection is generally more economic than alternative mitigation measures. The difference matters because the first erroneous

Figure 1 contradict this assumption and demonstrate that a rational project developer might prefer to pursue carbon offsets above pipeline sales, with the option to exit the Protocol and sell methane into a pipeline if relative carbon and natural gas prices do not justify the pursuit of offset credits. Indeed, the rational project developer might well prefer to view the Protocol as a hedge against low natural gas prices.

This situation is problematic and undermines the actually additionality of the Protocol. We recommend the Reserve revise the Protocol to prohibit switching from offset credits to pipeline sales, and vice versa.

Our understanding of VAM mitigation technologies is that no rational project developer would seek to invest in the capability to convert ventilation air (less than 1% methane) into pipeline quality gas (90-95% methane).[339] This investment would be necessary to create the option for temporal stacking described above. Thus, our concern applies only to drainage systems.

> **Response:** There is no conflict between the MMC protocol and the Clean Air Act (CAA). No action that ARB takes in execution of California's Cap-and-Trade Program precludes federal action on greenhouse gas emissions. The CAA does not empower ARB nor the commenter to determine what is the Best Available Control Technologies (BACT); that is left to regulators in mining states. Staff rejects the commenter's assessment that there is the potential for crediting non-additional projects or over-estimating reductions from individual projects based on the bad faith assumptions of regulators in other states charged with determining BACT as part of the Prevention of Significant Deterioration (PSD) permitting process under the CAA. Cited accounts of poor governance in international arena are not thought to be representative of regulatory agencies in the United States where the protocol is applicable.
>
> Additionally, staff does not agree that there is a foreseeable threat of invalidation of offset credits from emission reductions achieved under the MMC protocol. Project developers must meet the regulatory compliance requirements set forth in section 95973(b) of the Cap-and-Trade Regulation and offset credits will not be issued if a project is not in compliance with regulatory requirements. Staff sees no need to require a specific attestation from project developers stating that they are in compliance with all PSD permitting requirements and BACT determinations. First, to be eligible under the protocol, active mines must be classified as active, intermittent, or temporarily idle, thereby excluding mines that are planned, but not yet active, those referred to as "new" by the commenter. An offset project at a new mine will only be eligible for crediting of emission

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conclusion supports the Protocol's additionality criterion (which Figure 1 contradicts), whereas the second conclusion is consistent with both the data in Appendix A and the calculations in Figure 1.

[339] C. Özgen Karacan et al., *Coal mine methane: A review of capture and utilization practices with benefits to mining safety and to greenhouse gas reduction*, 86 INTERNATIONAL JOUNRAL OF COAL GEOLOGY 121, 147 (2011) (reviewing VAM characteristics and typical pipeline injection standards), *available at:* http://www.epa.gov/cmop/docs/cmm-paper-2011.pdf.

reductions in excess of what is required by any laws, regulations, and legally binding mandates requiring the destruction of methane at the time of offset project commencement, including those required for PSD permits during the construction phase. Similarly, a potential project at a mine undergoing major modifications will need to assess all laws, regulations, and legally binding mandates at time of offset project commencement. If an offset project has already commenced at a mine that subsequently undergoes modifications, any change to emission reduction requirements as a result of PSD permitting will be assessed at time of crediting period renewal. The use of crediting periods was explained in 2010 Staff Report: Initial Statement of Reasons (ISOR) and will again be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

In contrast to the arguments presented by the commenter, staff believes that it is likely that BACT standards could be strengthened by the MMC protocol as more mines utilize methane capture and destruction technologies promoted by the MMC protocol. Staff fundamentally disagrees with the commenter and perceives no need to create special eligibility criteria for new or expanding mines. Moreover, staff will periodically review new or modified regulations that could affect additionality as laid out in Compliance Offset Protocol Review Process available at: http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf. Staff does not believe that the Board should provide a schedule of time or event-based thresholds that would trigger a review of the protocol. Staff has already stated it will conduct a periodic review of all adopted protocols to ensure they represent the latest science in monitoring and quantification. This schedule of updates must be balanced against the market's need for certainty.

During the MMC protocol development process, ARB has endeavored to consider and respond to all comments made during the technical working group meetings and workshops. There was also extensive discussion about some of the concerns related to the MMC protocol at the October 2013 Board hearing. As with every rulemaking, ARB responds to all comments received during the formal comment periods in the final statement of reasons, which is developed after a Board vote and prior to submittal of the rulemaking package to the Office of Administrative Law.

The comments related to the perceived incentive to flare methane rather than put it to productive use will also be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.
The comment is also addressed in the next response.

The commenter's claim that the MMC protocol represents business-as-usual and concerns over additionality will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

The comments related to the eligibility criteria and additionality will be addressed in written responses to all comments included in the Final Statement of Reasons (FSOR) that will be made available in electronic form on the ARB rulemaking webpage at:
http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm.

The comments related to the potential increased profitability of coal mining are addressed in the response to the comment immediately following.

Comment: Comments on Board staff responses to three concerns raised by stakeholders at the October 2013 Board meeting

A. Economic analysis – the potential for profits generated by the MMC protocol to extend the lives of participating mines

At the October 2013 Board meeting, we and other stakeholders raised the concern that the profits generated from the MMC Protocol could be sufficient to extend the lives of some participating coal mines. Our concern focused on flaring projects at gassy underground coal mines where the MMC Protocol can increase mine profits by as much as 2% to 59% at $10 per offset credit. We also raised the concern that large Ventilation Air Methane (VAM) projects may also provide significant windfall profits to gassy underground mines as the sizes of these projects increase with experience and if offset prices were also to increase.

In the materials released with the current 15-day draft of the Protocol, Staff published an economic analysis that fails to respond to the specific concerns we raised pertaining to (1) the profitability of flaring projects at gassy underground mines primarily, and large VAM projects over time, and (2) the ability for offsets income from these projects to extend the operation of some mines. Instead, Staff's economic analysis examines the potential effect of the offset program on coal prices across the country and the potential effect on mine profits of three specific MMC projects – one at a surface mine and two small-scale VAM projects. Although we have not thoroughly reviewed the details of Staff's economic analysis, we note that the results of its analysis are what would be expected from the analysis that was performed. If we had chosen to analyze the same mines as Staff, we expect that we would have reached similar conclusions.

Our concern regards two project types that the Board staff's analysis fails to consider. In particular, we note that the profit margins of the three MMC projects chosen by the Board averaged 15%, while the US EPA's Coal Mine Methane Project Cash Flow

Model[340] predicted profit margins averaging 70% for the eight hypothetical flaring projects we assess in our analysis, as described in early comments, which are attached hereto for the Board's convenience. Given the potential sizes of flaring and VAM projects at active underground mines and their potential profits, it is conceivable that these two project types will generate a large portion of credits under the Protocol. We regret that Staff failed to perform an economic analysis that addresses the specific concerns raised at the October 2014 Board meeting – that profits generated under the Protocol by flaring projects at gassy underground mines could be large enough to extend mining operations, and that the same could be true for large VAM projects if offset prices were to increase substantially above $10 per offset credit.

We continue to strongly recommend that the Board amend the Protocol to avoid increasing mine profits enough to extend mine operations. This result can be accomplished by eliminating eligibility of drainage methane flaring at active underground mines or by placing a fee on credits generated by this project type. We also recommend that the Board include provisions in the Protocol to monitor the profits from VAM projects if project sizes and offset prices increase. Please see a more detailed description of these recommendations in Sections 2 and 3 of our comment letter to the Board dated February 14, 2014, and the details of our economic analysis of eight flaring and four large VAM projects in Section 8 of our comment letter to the Board dated October 23, 2013, both attached below.

February 14, 2014 (attached to written testimony submitted April 5, 2014)

(2) In order to avoid increasing mine profits by amounts large enough to extend the lives of some mines, the Board should consider eliminating eligibility of drainage methane flaring at active mines or placing a fee on credits generated by this project type. Such a change would also create greater incentive for mines to capture drainage methane for productive use rather than for flaring. We also suggest that the Board commit to monitoring the offset profits earned from drainage methane and ventilation air methane (VAM) capture projects as offset prices change and as experience is gained with these technologies. We suggest that the Board include provisions for a response if, in fact, profits become large enough to extend mine operation.

There is substantial evidence that flaring projects from drainage wells at active underground mines can increase mining profits enough to affect mining operation. A simple assessment of eight of the ten US coal mines with drainage wells that do not already capture most of their drainage methane shows the potential for offset revenues to increase mining profits by 2% to 59% at $10 per offset credit (see Table 1 in our comments to the Board from 23 October 2013 attached hereto). These large profits are due to the large quantities of methane currently vented from these wells and the low cost of implementing and operating flaring systems. While increases in mining profits will be even larger if offset prices rise, profits at $10 per offset credit are already large enough to extend the life of a struggling gassy mine. Excluding flaring or creating a

[340] http://www.epa.gov/methane/cmop/resources/cashflow_model.html accessed 20 October 2013

differential offset price for flaring projects with a fee can avoid large windfall profits to the gassiest mines.

In addition, this recommendation (in either of its variations) also creates greater incentive for mines to capture drainage methane for productive use rather than for flaring. The Board should design the Protocol to create incentives for the capture and use of drainage methane when such projects are cost effective with offset credit sales. Under the current draft Protocol, it is likely that mines that do not already capture methane for use will find flaring more cost effective than pipeline sales because flaring projects are less expensive to implement. Since mine methane is a valuable natural resource with added benefit to the climate if it is used, the Board should avoid incenting flaring when use is reasonably possible with the help of the Protocol.

Lastly, we suggest that the Board commit to monitoring the offset profits earned from drainage methane and ventilation air methane (VAM) capture projects as offset prices change and as experience is gained with these technologies. We suggest that the Board include provisions for a response if, in fact, profits become large enough to extend mine operation.

Our economic analyses continue to show the potential for windfall profits to coal mining operations from the incentives created by the Protocol. We look forward to reviewing the Board staff's analysis of the potential for these profits.

October 23, 2013 (attached to written testimony submitted April 5, 2014)

Improving coal mine profits: The Protocol has the potential to substantially improve coal mining profits for some participating coal mines, improving their financial standing at the present time when coal is competing neck-to-neck with natural gas and many coal mines are shutting down.

Recommendation: The Board should only adopt the Protocol if conservative analysis shows that the increase in mining profits from offsets revenues will not result in an increase in production or use of coal, or that any increase will be small and is accounted for by the Protocol.

In our July 1, 2013 comments to the Board on the Protocol (attached hereto) we showed that the Protocol has the potential to meaningfully increase the profits of some participating coal mines. We recommended that the Board perform a more detailed analysis examining the potential for increased profits to lead to an increase in the production and use of coal. We made this recommendation with the understanding that increasing coal mining profits must not be taken lightly. When offsets are allowed to be generated by high emitting industries, they in effect subsidize that industry. Subsidizing coal mining – the most carbon intensive of industries – is especially a concern at the present moment when, due to declines in natural gas prices, coal and natural gas are in close competition as fuels for electricity generation. Over the past few years natural gas has replaced some coal as base load in the United States, and small differences in fuel prices are affecting marginal dispatch of power plants. We recommended that the Board perform an analysis that examines the potential effects of the revenues generated by the Protocol on the production and use of coal.

ARB staff response to this concern: ARB staff assessed the potential financial impact of the Protocol on participating coal mines, estimating that offsets revenues would amount to less than one percent of mining revenues, and that offsets profits would amount to less than one percent of mining profits. They conclude that this small increase in revenues is inconsequential to the market. We understand that the Board's analysis is based on the assumption that a typical MMC project has a profit margin of around 15% (meaning that MMC project implementation costs equal around 85% of offsets revenues).

Our early analysis submitted to the Board in our letter dated July 1, 2013 showed that the effect of the MMC protocol on profits is potentially significant on some participating mines and pointing to the need for the Board to do its own analysis of this consequence of the Protocol.

We question the Board's assumption that the profit margin of MMC projects is only 15%. An analysis must not only assess the effects of the Protocol on an average mine, but also the effects on those mines most likely to participate in the Protocol and those most likely to be affected by the increased income. The Protocol will have a disproportionate impact on decisions at the gassiest mines and those mines that are on the verge of closing. To understand the impacts of the Protocol, the Board's analysis should assess those impacts on the range of mines it could influence.

We used the US Environmental Protection Agency's (EPA's) Coal Mine Methane Project Cash Flow Model to examine the costs of MMC projects for twenty sample projects.[341] We build on our analysis from July 1 which estimated the potential effect of offsets, at $10 per tCO_2e, on ten gassy active underground mines that the EPA has identified as having drainage wells, but where mine operators were venting (i.e., not destroying) either all or nearly all mine methane emissions in 2006.[342] We analyzed two methane capture projects at each mine: one which flared all of the drainage methane previously vented to the atmosphere, and a second which oxidized 50% of the ventilation air methane.

The EPA Cash Flow Model predicts that eight mines with drainage methane flows greater than one million cubic feet per day are viable candidates for flaring projects. These eight projects are predicted to have profit margins between 40% and 92%, with an average of 70%. The Cash Flow Model predicts that the mines with ventilation air methane (VAM) concentrations of 0.8% or greater are viable candidates for VAM oxidation projects. Predicted profit margins for these projects range from 40% to 53%,

[341] http://www.epa.gov/methane/cmop/resources/cashflow_model.html accessed 20 October 2013
[342] EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003

with an average of 46%. Each of these estimates used mine-specific methane flows and VAM concentrations as reported by the EPA,[343] and mid-point values for each project cost parameter for which the Model displayed a range of possible inputs. The use of average values for all cost parameters means that some modeled MMC projects will have higher profit margins and others lower, depending on the actual cost of the particular project. We include a moderate assessment of annual monitoring and verification costs in our analysis, which is too small to meaningfully affect our profit analysis.

Table 1 shows the results of these revised estimates in terms of the possible effects of carbon offset profits on mining profits.[344] Using the assumptions described herein, we find that flaring projects can increase mining profits by an average of 12% for the eight modeled flaring projects, and VAM projects can increase mining profits by 5% for the four modeled VAM projects. These numbers would be higher if mine profit margins or MMC implementation costs are less than average, or if offsets prices exceed $10 per tonne CO_2e. We continue to believe that the potential profit margins of these magnitudes for some MMC offsets projects are large enough to suggest that the Board should perform a more detailed analysis to better understand the effects of these profits on the production and use of coal.

TABLE 1: OFFSETS PROFITS AS % OF COAL MINING PROFITS

For hypothetical offsets projects

assuming a 9.4% coal mining profit margin without offsets

		at an offsets price of:		
Mine	**State**	**$10**	**$20**	**$50**
FLARING PROJECTS (using 100% of drainage methane)				
McElroy Mine	WV	4%	7%	18%
Bailey Mine	PA	6%	12%	31%
San Juan South	NM	10%	20%	50%
West Elk Mine	CO	59%	118%	296%
Robinson Run No. 95	WV	4%	8%	21%
Elk Creek Mine	CO	10%	20%	51%
Federal No. 2	WV	2%	3%	9%
American Eagle	WV	4%	9%	22%
	Average:	**12%**	**25%**	**62%**
	Range:	**2% - 59%**	**3% - 118%**	**9% - 296%**
VAM PROJECTS (oxidizing 50% VAM)				
McElroy Mine	WV	7%	15%	37%
Bailey Mine	PA	4%	7%	18%
Robinson Run No. 95	WV	4%	7%	19%
Federal No. 2	WV	6%	11%	28%
	Average:	**5%**	**10%**	**25%**
	Range:	**4% - 7%**	**7% - 15%**	**18% - 37%**

[343] EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003, and EPA. 2010. U.S. Underground Coal Mine Ventilation Air Methane Exhaust Characterization

[344] Since we do not have profit data for the specific mines we examine, we apply, in our analysis, a profit margin of 9.4%. This is the average profit margin over a five year period from 2008 to 2012 achieved by six U.S. coal mining companies: Alliance Resource Partners, Alpha Natural Resources, Arch Coal, CONSOL, Patriot Energy, and Walter Industries.12 These six companies are the only companies listed in the EPA 2009 report as owners of large gassy underground U.S. coal mines with publically available annual reports that focus their business primarily on coal mining

July 1, 2013 (attached to written testimony submitted April 5, 2014)

The Board should examine and monitor the potential for emissions leakage resulting from increases in the profitability of coal mining due to revenues from offset credits under the Protocol.

Appendix C demonstrates that offsets revenues for MMC projects can substantially improve the profits of companies engaged in underground coal mining. At carbon offset prices as low as $10 per tonne of carbon dioxide equivalent (tCO_2e), offset revenues can increase the profits of an underground coal mine with an average profit margin and level of gassiness by approximately 13%, and can increase mine profits by over 50% at the gassiest mines and at mines with relatively low profit margins. An offset price of \$50/tCO_2e would lead to an increase in profits of an average coal mine by around 66%, while more than doubling the profits of the most gassy mines and at mines with relatively low profit margins. We encourage the Board to perform its own examination of the possible leakage emissions that could be induced by the Protocol and to monitor this risk as energy prices and conditions change, methane capture technologies improve, and offsets prices increase. The leakage risk created from increasing mine profits means that the conservative choice of project eligibility criteria to prevent any non- additional projects from participating are especially crucial for this protocol.

In conclusion, we emphasize that the risks associated with an MMC Protocol go beyond crediting non-additional projects and over-estimating reductions from individual projects. The potential for an MMC Protocol to cause a weakening of BACT standards, to incentivize flaring over productive methane use, and to increase profits from coal mining could lead to an increase in emissions substantially greater than the credits generated. Our analyses find that these effects may be substantial. The Board should take affirmative steps to avoid these effects in the design of the Protocol, through applying conservative project eligibility criteria, developing safeguards against conflicts with the Clean Air Act, and monitoring these effects as technologies and conditions change over time.

Appendix C of July 1, 2013 letter (attached to written testimony submitted April 5, 2014)

APPENDIX C

The Effects of a Mine Methane Capture Protocol on Coal Mining Profits

At the first Potential Mine Methane Capture (MMC) Compliance Offset Protocol Technical Working Group meeting on May 3rd, 2013, we mentioned that we were analyzing the potential effects of revenues from offset credits generated by coal mine methane destruction on the on coal mining operations and the risk of leakage emissions resulting from this new revenue source. Below are the results of this analysis.

1. Summary of Results

We find that offsets revenues from MMC projects can substantially improve the profits of companies engaged in underground coal mining. At carbon offset prices as low as \$10 per tonne of carbon dioxide equivalent (tCO_2e), offset revenues can increase the profits of an underground coal mine with an average profit margin and level of gassiness by 13%, and can increase mine profits by over 50% at the gassiest mines and at mines with relatively low profit margins. An offset price of \$50/tCO_2e would lead to an increase in profits of an average coal mine by 66%, while more than doubling the profits of the most gassy mines and of mines with relatively low profit margins. Further, income from offsets would also provide coal mining companies with some buffer against annual variability of revenues from coal sales, such as results from relatively common temporary mine closures.[345] Increases in coal mine profits from offsets would come at a time when coal and natural gas are in close competition as fuels for electricity generation; small differences in fuel prices can affect the marginal dispatch order of power plants, and in turn, their associated greenhouse emissions. This set of conditions suggest that by substantially increasing the profits of some coal mines, the MMC protocol has the potential to induce leakage in the form of increased emissions from continued and expanded mining operations.

These results derive from an analysis of the revenues that could be generated from mine methane capture projects at the ten gassy active underground mines that the EPA has identified as having drainage wells, but where mine operators were venting (i.e., not destroying) either all or nearly all mine methane emissions in 2006.[346] For these ten mines, we analyze the potential offsets revenues from twenty hypothetical projects: the capture of 100% of drainage/gob methane emissions from each of the ten mines, and the capture of 50% of ventilation air methane emissions ("VAM") from each of the ten mines. We use offsets prices of \$10, \$20 and \$50 per tCO_2e to examine the potential for carbon offsets revenues to meaningfully improve the economics of underground coal mining. Since this analysis uses average state-level coal prices, average mining profit margins, and mine-specific coal production and methane emissions from a single year (2006), this analysis is meant to provide insight into the range of financial benefits that could be derived from MMC offsets projects at active underground coal mines, rather than an assessment of the financial benefits of specific methane capture projects at specific mines. The assumptions used in this analysis are described below in the "Details of the Analysis" section.

[345] Mines continue to emit methane when active mining operations have been suspended.
[346] EPA. 2009. Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006. EPA 430-K-04-003

TABLE 1: OFFSETS REVENUES AS % OF COAL MINING PROFITS

For 20 hypothetical offsets projects assuming a 9.4% coal mining profit margin without offsets

Mine	State	Offsets project	at an offsets price of: $10	$20	$50
McElroy Mine	WV	100% drained	5%	10%	26%
		50% VAM	14%	29%	71%
Bailey Mine	PA	100% drained	8%	16%	39%
		50% VAM	9%	18%	46%
San Juan South	NM	100% drained	13%	27%	67%
		50% VAM	10%	20%	51%
West Elk Mine	CO	100% drained	64%	129%	322%
		50% VAM	32%	64%	161%
Robinson Run No. 95	WV	100% drained	7%	14%	35%
		50% VAM	8%	16%	41%
Elk Creek Mine	CO	100% drained	16%	32%	79%
		50% VAM	23%	47%	117%
Federal No. 2	WV	100% drained	5%	10%	25%
		50% VAM	15%	29%	73%
Bowie No. 2	CO	100% drained	5%	10%	24%
		50% VAM	7%	14%	36%
Dugout Canyon	UT	100% drained	3%	6%	16%
		50% VAM	5%	11%	26%
American Eagle	WV	100% drained	7%	13%	34%
		50% VAM	5%	10%	25%
		Average:	**13%**	**26%**	**66%**
		Range:	**3% - 64%**	**6% - 129%**	**16% - 322%**

Table 1 shows the potential effects on coal mine profits from the revenues for offsets generated by the twenty mine methane capture projects analyzed. We find the potential for large profit increases from MMC offsets. Profit margins vary dramatically among companies and over time. The impact that offsets revenues could have on the profits of mines with lower-than- average profit margins, which are also those mines most at risk of closure, would be larger than the results given here.

We did not perform a full analysis of the emissions leakage that might result from an increase in mine profits from offsets. Determining the extent to which increases in mining profits may cause an increase in coal use from individual mines is substantially more complex and involved than the analysis provided herein. Increasing the profitability of gassy mines generating offsets credits under the Protocol may enable some mines to expand operations or avoid closure. If these gassy mines displace coal that otherwise would have been produced by less gassy mines, the Protocol could result in a large increase in methane emissions that is unaccounted for by the Protocol. A second avenue by which increased coal mining profits can cause emissions leakage is if the increased profits result in lowered coal prices. This is of particular concern under present conditions, considering that reductions in natural gas prices over the last several years have lead to a substantial shift from coal to natural gas as fuels used to generate electricity in the United States.[347] We encourage the Board to perform its own examination of the possible leakage emissions that could be induced by the increase in

[347] Pratson, L. F., D. Haerer & D. Patiño-Echeverri (2013) Fuel Prices, Emission Standards, and Generation Costs for Coal vs Natural Gas Power Plants. *Environental Science & Technology*, 4926−4933

mining profits shown here and to monitor this risk as energy prices and conditions change, methane capture technologies improve, and offsets prices increase.

The leakage risk created by choosing to credit emissions reduction projects at facilities that produce coal, a fuel responsible for a large portion of the country's greenhouse gas emissions, suggests that conservative project eligibility criteria that avoid crediting any non- additional activity is especially crucial for this Protocol. Since the main costs of a non-additional offsets projects are monitoring and verification (technology costs of the offsets project are effectively zero since the technology would have been implemented anyway), revenues from non-additional projects go directly into profits. Until the leakage risk is better understood, it is best to take extra precaution to avoid windfall profits to non-additional activities by establishing conservative eligibility criteria.

2. Details of the Analysis

We estimate coal revenues using coal prices from underground coal mines by state and by type of coal (steam or metallurgical) obtained from the Energy Information Administration's (EIA's) 2012 Annual Coal Report averaged over 2010-2011.[348] For the quantities of coal mined, we use data from 2006, compiled in the EPA 2009 report on mine methane emissions.

Since we do not have profit data for the ten specific mines we examine, we apply, in our analysis, a profit margin of 9.4%. This is the average profit margin over a five year period from 2008 to 2012 achieved by six U.S. coal mining companies: Alliance Resource Partners, Alpha Natural Resources, Arch Coal, CONSOL, Patriot Energy, and Walter Industries.[349] These six companies are the only companies listed in the EPA 2009 report as owners of large gassy underground U.S. coal mines with publically available annual reports that focus their business primarily on coal mining.

To compare offsets revenues with coal mining profits, we assume very low offsets project implementation costs compared to offsets revenues, such that practically all of the calculated revenues go directly into profits. This would be true for non-additional projects, for which the main costs are monitoring and verification, and for technologies with implementation costs well below offsets income, as would likely be the case for flaring projects.[350] The effects of carbon offsets on mining profits would be less significant for offsets projects with costs that are closer in size to the revenues generated by the offsets project.

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[348] U.S. Energy Information Administration. 2012. Annual Coal Report 2011. Washington, DC. Table 28. Average sales price of coal by State and mine type, 2011, 2010, http://www.eia.gov/coal/annual/.

[349] Profit margins between 2008 to 2012 taken from these companies' annual reports, are as follows: Alliance Resource Partners: 17.0%, Alpha Natural Resources: 2.6%; Arch Coal: 8.0% (we use a zero profit margin during 2012 when Arch Coal had negative profits); CONSOL: 9.1%; Patriot Energy: 3.0% (we use a zero profit margin during 2010 to 2012 when Patriot Energy had negative profits); Walter Industries: 16.6% (we use a zero profit margin during 2012 when Walter Industries had negative profits).

[350] Ranges of capital and operating costs for CMM flaring projects are documented in the US EPA Coal Mine Methane Project Cash Flow Model, http://www.epa.gov/cmop/resources/cashflow_model.html (accessed 11 June 2013)

Table 2 provides information about the ten mines and twenty projects analyzed, including estimates of their revenues from offsets and coal sales based on the assumptions described above. The last columns of this table shows offsets revenues as a percentage of coal sales revenues for various offsets prices.

The maximum values of offsets revenues as a percentage of coal sales revenues shown in this table are from a gassy mine that was closed for several months in 2006 (West Elk Mine). The temporary closure of this mine resulted in relatively high methane emission per ton of coal produced, since methane continues to vent even when mining operations have been paused. While this mine produces methane at substantially higher rates per ton of coal produced than the other nine mines analyzed, temporary mine closures are common, and EPA's 2009 report which provides data on fifty active gassy underground mines shows that these levels of methane emissions per ton coal produced are not uncommon and can be much higher.

We would be more than happy to provide the spreadsheet used in this analysis.

Table 2: Mine methane capture carbon offest revenues compared with gross coal sales revenues

		COAL REVENUES				OFFSETS REVENUES					OFFSETS REVENUES AS % OF GROSS COAL REVENUES		
								Revenues (mill$) at an offsets price of:			at an offsets price of:		
Mine	State	Coal mined in 2006 (mill tons) (1)	Coal type: steam or metallurgical (1)	$ / ton coal (2)	Revenues from coal sales (mill$)	Offsets projects assessed	Methane that would be captured (MTCO2e) (1)	$10	$20	$50	$10	$20	$50
McElroy Mine	WV	10.5	Steam	$58.11	$610.10	100% drained	0.29	$2.94	$5.88	$14.71	0.5%	1.0%	2.4%
						50% VAM	0.82	$8.19	$16.37	$40.93	1.3%	2.7%	6.7%
Bailey Mine	PA	10.2	Steam (4)	$54.78	$558.71	100% drained	0.41	$4.09	$8.19	$20.46	0.7%	1.5%	3.7%
						50% VAM	0.48	$4.80	$9.59	$23.98	0.9%	1.7%	4.3%
San Juan South	NM	7.0	Steam	$37.44	$262.08	100% drained	0.33	$3.33	$6.65	$16.63	1.3%	2.5%	6.3%
						50% VAM	0.25	$2.5	$5.0	$12.5	1.0%	1.9%	4.8%
West Elk Mine	CO	6.0	Steam	$32.02	$192.09	100% drained	1.16	$11.6	$23.3	$58.2	6.1%	12.1%	30.3%
						50% VAM	0.58	$5.8	$11.6	$29.1	3.0%	6.1%	15.1%
Robinson Run No. 95	WV	5.7	Steam	$58.11	$331.20	100% drained	0.22	$2.2	$4.3	$10.9	0.7%	1.3%	3.3%
						50% VAM	0.26	$2.6	$5.1	$12.8	0.8%	1.5%	3.9%
Elk Creek Mine (3)	CO	5.1	Steam	$32.02	$163.28	100% drained	0.24	$2.4	$4.9	$12.2	1.5%	3.0%	7.4%
						50% VAM	0.36	$3.6	$7.2	$17.9	2.2%	4.4%	11.0%
Federal No. 2	WV	4.6	Steam	$58.11	$267.28	100% drained	0.13	$1.3	$2.6	$6.4	0.5%	1.0%	2.4%
						50% VAM	0.36	$3.6	$7.3	$18.2	1.4%	2.7%	6.8%
Bowie No. 2	CO	4.4	Steam	$32.02	$140.87	100% drained	0.06	$0.6	$1.3	$3.2	0.5%	0.9%	2.3%
						50% VAM	0.10	$1.0	$1.9	$4.8	0.7%	1.4%	3.4%
Dugout Canyon	UT	4.4	Steam	$38.13	$167.77	100% drained	0.05	$0.5	$1.0	$2.6	0.3%	0.6%	1.5%
						50% VAM	0.08	$0.8	$1.7	$4.2	0.5%	1.0%	2.5%
American Eagle	WV	2.4	Both (5)	$169.02	$405.64	100% drained	0.26	$2.6	$5.1	$12.8	0.6%	1.3%	3.2%
						50% VAM	0.19	$1.9	$3.8	$9.6	0.5%	0.9%	2.4%
										Average:	1.2%	2.5%	6.2%
										Range:	0.3% - 6.1%	0.6% - 12.1%	1.5% - 30.3%

Response: The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

The assumptions and level of analysis contained within ARB's mining economics study differed from those of the commenter's. In reviewing the figures provided by the commenter, staff found several assumptions that were flawed and not the least of which was reliance upon the U.S. EPA's Coal Mine Methane Project Cash Flow Model which contains the explicit disclaimer that "the model was NOT DESIGNED for conducting a detailed economic analysis". The dissatisfaction expressed in the April 5th letter to ARB can be summarized as criticizing the analysis for not taking the same approach to the subject as the commenter. The analysis provided by ARB included not only a microeconomic analysis at the project level but also a macroeconomic analysis of the market for coal, the primary factor influencing coal production decisions. Staff maintains that the proposed MMC protocol will not incentivize the production or burning of coal. Rather, the protocol provides an incentive to reduce the potent greenhouse gas emissions otherwise emitted during the mining process.

The comments related to the perceived incentive to flare mine methane over productive utilization are addressed in the response to the comment immediately preceding this one and will be addressed further in the FSOR, as the incentive to flare mine methane is distinct and separate from the environmental analysis associated with flaring mine methane.

TAYLORR

Name: Jeremy Taylorr
Affiliation: Private Individual
Written Testimony: 3/31/2014
15-Day Comment #: 35

Comment: Most of the Energy efficiency with Oil and coal degrades our environment and alternative sources need to be considered, other wise our environments sustain ability will only continue to degrade. Please do you part to sustain a better living Environment!

> **Response:** The limited use of offsets serves as an important cost-containment feature in the Cap-and-Trade Program, which reduces emissions and works in conjunction with other AB 32 measures that shift California's energy consumption toward renewable sources. An environmental analysis of the proposed MMC protocol concluded that its potential impacts to air quality would likely not be adverse, and where an adverse impact may occur would be less than significant due to the requirement that all projects comply with all applicable federal, state and local laws and regulations. The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

THORNBURGH

Name: Jack Thornburgh
Affiliation: Peninsula EcoVision
Written Testimony: 4/2/2014
15-Day Comment #: 55

Comment: The Mine Methane Capture Protocol will only encourage further coal extraction and burning, leading to more GHGs. Please reconsider

> **Response:** The MMC protocol incentivizes the capture and destruction of methane that would otherwise be vented into the atmosphere as a result of mining operations. Staff does not believe the MMC protocol incentivizes the extraction or burning of coal that would otherwise remain unearthed and therefore does not increase emissions from the mining industry. In response to Board Resolution 13-44, staff released The Mine Methane Capture Protocol and Mining Economics study. The study approached the issue from various perspectives including comparing the value of offsets to the value of coal, evaluating the likelihood that the protocol would encourage new coal mines to begin production or encourage existing mines to produce more coal, assessing whether the protocol would shift production between existing coal mines, or impact the price of coal. From this analysis, staff concluded that the MMC protocol would have a nearly imperceptible impact on mine economics. While the protocol presents an opportunity to achieve emission reductions in a carbon-intensive industry, it would not encourage additional coal mining. On average, the rate of return from the MMC offset project would increase coal mine profits by less than one percent, which would not shift long-term production decisions. The analysis is available in electronic form on the ARB rulemaking webpage at: http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

ATTACHMENT B: ACRONYMS

AAR	Alternative account representative
AB32	Assembly Bill 32 -- California Global Warming Solutions Act of 2006
ACR	American Carbon Registry
APCR	Allowance Price Containment Reserve
APD	Authorized Project Designee
ARB	California Air Resources Board
AVA	Account Viewing Agents
AEPCO	Arizona Electric Power Co-op
CAISO	California Independent System Operator
CAR	Climate Action Reserve
CARBIS	California Air Resources Board Information System
CCA	California Carbon Allowance
CCR	California Code of Regulations
CEA	Commodities Exchange Act
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFTC	Commodity Futures Trading Commission
CHP	Combined Heat and Power
CITSS	Compliance Instrument Tracking System Service
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CHP	combined heat and power
CPUC	California Public Utilities Commission
CWB	Complexity weighted barrel
CWT	Carbon weighted ton
DOJ	Department of Justice
DWR	Department of Water Resources
EDU	Electrical Distribution Utilities
EIM	Energy Imbalance Market
EITE	Energy-intensive, trade-exposed
EMAC	Emissions Market Assessment Committee
EO	Executive Officer
EPA	U.S. Environmental Protection Agency
EPS	California's Emissions Performance Standard
ETS	Emissions Trading Scheme
EU ETS	European Union Emissions Trading System
FED	Functional Equivalent Document
FERC	Federal Energy Regulatory Commission
FINRA	Financial Industry Regulatory Authority
FSA	financial services administrator
FSOR	Final Statement of Reasons
GHG	greenhouse gas
GWP	global warming potential
HSC	Health and Safety Code

ICE	Intercontinental Exchange
IETA	International Emissions Trading Association
IOU	investor-owned utility
IPP	independent power producer
ISO	International Organization for Standardization
ISOR	Initial Statement of Reasons
JPA	Joint Powers Agency
k SCF/cd	Thousands of standard cubic feet per calendar day
KYC	Know Your Customer
LADWP	Los Angeles Department of Water and Power
LAO	Legislative Analyst's Office
LSE	load serving entity
LUHA	limited use holding accounts
MMC	Mine Methane Capture
MMscf	Million standard cubic feet
MRR	Mandatory Reporting of Greenhouse Gas Emissions Regulation
MSG	Market Simulation Group
MSW	Municipal Solid Waste
$MTCO_2e$	Metric ton of carbon dioxide equivalent
$MMTCO_2e$	Million metric tons of carbon dioxide equivalent
MWD	Metropolitan Water District
NAFTA	North American Free Trade Agreement
NAICS	North American Industry Classification System
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFA	National Futures Association
NOx	oxides of nitrogen
ODS	ozone depleting substance
OPO	Offset Project Operator
PAR	Principal account representative
PG&E	Pacific Gas and Electric
POU	publicly owned utility
PPA	Power Purchasing Agreement
PSE	purchasing-selling entity
PUC	See CPUC
QE	qualified export
QF	Qualifying Facilities
REC	Renewable Energy Credit
REDD	United Nations Collaborative Programme on Reducing Emissions from Deforestation and Forest Degradation in Developing Countries
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewables Portfolio Standard
SB 1368	Senate Bill 1368 -- Emission Performance Standards
SDG&E	San Diego Gas and Electric
SEC	Securities and Exchange Commission
SMUD	Sacramento Municipal Utility District

SWP	California State Water Project
UNFCCC	United Nations Framework Convention on Climate Change
UOG	Utility-Owned-Generation
VAE	voluntarily associated entity
VCS	Verified Carbon Standard
VRE	voluntary renewable energy
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WREGIS	Western Renewable Energy Generation Information System
WSPA	Western states petroleum association