California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

Thursday, October 24, 2013 and Friday, October 25, 2013

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814
http://www.calepa.ca.gov/EPAbldg/location.htm

This facility is accessible by public transit. For transit information, call (916) 321-BUSS, website: http://www.sacrt.com
(This facility is accessible to persons with disabilities.)

TO SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO: http://www.arb.ca.gov/lispub/comm/bclist.php

Thursday
October 24, 2013
9:00 a.m.

DISCUSSION ITEMS:

Note: The following agenda items may be heard in a different order at the Board meeting.

Agenda Item #

13-9-3: Status Report to the Board on the Advanced Clean Cars Program

Staff will update the Board on the Advanced Clean Cars Program and plans for the midterm review of the program.

13-9-4: Public Hearing to Consider Minor Modifications to the Zero Emission Vehicle Regulation

Staff will present to the Board proposed minor amendments to the Zero Emission Vehicle Regulation.

13-9-5: Status Update to the Board on Implementation of the Truck and Bus Regulation
(This item will not be heard prior to 1:00 p.m. on Thursday, October 24, 2013)

Staff will present to the Board a status update on the implementation of the Truck and Bus Regulation. This will include a brief overview of the Regulation, a discussion of the Air Resources Board's efforts to assist fleets with compliance through outreach, planning and incentive funding opportunities, enforcement efforts to ensure high levels of compliance, and future efforts to build on the successes to date.

13-9-6: Informational Status Report to the Board on the Assembly Bill 32 Scoping Plan Update Discussion Draft

Staff will present to the Board a status report on the Assembly Bill 32 Scoping Plan Update Discussion Draft.

Friday
October 25, 2013
8:30 a.m.

13-9-7: Public Hearing to Consider a Proposed Regulation for State Implementation Plan Credit From Mobile Agricultural Equipment

Staff will present to the Board a proposed regulation that will provide an administrative mechanism to receive State Implementation Plan credit for emission reductions from agricultural equipment that are achieved through incentive programs. The proposed regulation complements the SIP credit rule for agricultural equipment adopted by the San Joaquin Valley Air Pollution Control District. The proposed regulation would provide for an opt-in for any other California air district that complies with the regulation.

13-9-8: Public Hearing to Consider Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Staff will present to the Board minor revisions to the Air Resources Board's (ARB) current regulation for the mandatory reporting of greenhouse gas (GHG) emissions. The proposed amendments will support the Cap-and-Trade Regulation by collecting additional information to ensure the accuracy of the data used for benchmarking, allocation of allowances, and the covered emissions calculation. Additionally, the proposed amendments will clarify the reporting requirements to ensure the GHG data are accurate and complete in order to support other ARB Climate Change programs.

13-9-9: Public Hearing to Consider Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms

Staff will present to the Board proposed amendments to the Cap-and-Trade Regulation related to implementation, allocation, cost containment mechanisms, and other specific directions from the Board.

CLOSED SESSION

The Board will hold a closed session, as authorized by Government Code section 11126(e), to confer with, and receive advice from, its legal counsel regarding the following pending or potential litigation, and as authorized by Government Code section 11126(a):

POET, LLC, et al. v. Goldstene, et al., Superior Court of California (Fresno County), Case No. 09CECG04850; plaintiffs' appeal, California Court of Appeal, Fifth District No. F064045.

Rocky Mountain Farmers Union, et al. v. Corey, U.S. District Court (E.D. Cal. Fresno), Case No. 1:09-CV-02234-LJO-DLB; interlocutory appeal, U.S. Court of Appeal, Ninth Circuit Nos. 09-CV-02234 and 10-CV-00163.

American Fuels and Petrochemical Manufacturing Associations, et al. v. Corey, et al., U.S. District Court (E.D. Cal. Fresno), Case No. 1:10-CV-00163-AWI-GSA; interlocutory appeal, U.S. Court of Appeal, Ninth Circuit, Case Nos. 09-CV-02234 and 10-CV-00163.

Association of Irritated Residents, et al. v. United States Environmental Protection Agency, 2011 WL 310357 (C.A.9), (Feb. 2, 2011).

California Dump Truck Owners Association v. Nichols, U.S. District Court (E.D. Cal. Sacramento), Case No. 2:11-CV-00384-MCE-GGH; plaintiffs' appeal, U.S. Court of Appeals, Ninth Circuit, Case No. 13-15175.

California Construction Trucking Association v. United States Environmental Protection Agency, U.S. Court of Appeals, Ninth Circuit, Case No. 13-70562.

Engine Manufacturers Association v. California Air Resources Board, Sacramento Superior Court, Case No. 34-2010-00082774.

Citizens Climate Lobby and Our Children's Earth Foundation v. California Air Resources Board, San Francisco Superior Court, Case No. CGC-12-519554, plaintiffs' appeal, California Court of Appeal, First District, No. A138830.

California Chamber of Commerce et al. v. California Air Resources Board, Sacramento Superior Court, Case 34-2012-80001313.

Morning Star Packing Company, et al. v. California Air Resources Board, et al., Sacramento Superior Court, Case No. 34-2013-800001464.

Delta Construction Company, et al. v. United States Environmental Protection Agency, U.S. Court of Appeals, District of Columbia Circuit, Case No. 11-1428.

City of Los Angeles through Department of Water and Power v. California Air Resources Board, et al., Los Angeles Superior Court, Case No. BS140620.

OPPORTUNITY FOR MEMBERS OF THE BOARD TO COMMENT ON MATTERS OF INTEREST

Board members may identify matters they would like to have noticed for consideration at future meetings and comment on topics of interest; no formal action on these topics will be taken without further notice.

OPEN SESSION TO PROVIDE AN OPPORTUNITY FOR MEMBERS OF THE PUBLIC TO ADDRESS THE BOARD ON SUBJECT MATTERS WITHIN THE JURISDICTION OF THE BOARD

Although no formal Board action may be taken, the Board is allowing an opportunity to interested members of the public to address the Board on items of interest that are within the Board's jurisdiction, but that do not specifically appear on the agenda. Each person will be allowed a maximum of three minutes to ensure that everyone has a chance to speak.

TO ELECTRONICALLY SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO:

http://www.arb.ca.gov/lispub/comm/bclist.php

(Note: not all agenda items are available for electronic submittals of written comments.)

ONLINE SIGN-UP:

You can sign up online in advance to speak at the Board meeting when you submit an electronic Board item comment. For more information go to:

http://www.arb.ca.gov/board/online-signup.htm

(Note: not all agenda items are available for online sign-up.)

IF YOU HAVE ANY QUESTIONS, PLEASE CONTACT THE CLERK OF THE BOARD:
1001 I Street, 23rd Floor, Sacramento, California 95814
(916) 322-5594
ARB Homepage: www.arb.ca.gov

SPECIAL ACCOMMODATION REQUEST

Consistent with California Government Code Section 7296.2, special accommodation or language needs may be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 7 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Consecuente con la sección 7296.2 del Código de Gobierno de California, una acomodación especial o necesidades lingüísticas pueden ser suministradas para cualquiera de los siguientes:

- Un intérprete que esté disponible en la audiencia
- Documentos disponibles en un formato alterno u otro idioma
- Una acomodación razonable relacionados con una incapacidad

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envié un fax a (916) 322-3928 lo más pronto posible, pero no menos de 7 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

SMOKING IS NOT PERMITTED AT MEETINGS OF THE CALIFORNIA AIR RESOURCES BOARD

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

LOCATION:
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Byron Sher Auditorium, Second Floor
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CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC MEETING TO PROVIDE A STATUS REPORT TO THE AIR RESOURCES BOARD ON THE ADVANCED CLEAN CARS PROGRAM

The Air Resources Board (ARB or Board) will conduct a public meeting at the time and place noted below to hear a status report on the Advanced Clean Cars (ACC) Program

DATE: October 24, 2013

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item will be heard at a two-day meeting of the Board, which will commence at 9:00 a.m., October 24, 2013, and may continue at 8:30 a.m., on October 25, 2013. This item may not be heard until October 25, 2013. Please consult the agenda for the meeting, which will be available at least 10 days before October 24, 2013, to determine the day on which this item will be presented.

In January 2012, ARB approved the ACC program, a comprehensive landmark policy that included increased zero-emission vehicle (ZEV) requirements through the 2025 model year, and the next generation of light- and medium- duty greenhouse gas (GHG) and criteria pollutant emission standards (LEV III). This historic program, developed in coordination with the U. S. Environmental Protection Agency (U.S. EPA) and the National Highway Traffic Safety Administration (NHTSA), combined the control of smog-causing pollutants and GHG emissions into a single coordinated set of requirements for model years 2017 through 2025 and assured the development of environmentally superior cars that will continue to deliver the performance, utility, and safety vehicle owners have come to expect all while saving the consumer money through fuel savings. The Board approved subsequent minor amendments to the ACC program in November 2012, and a final U.S. EPA waiver was granted in January 2013.

In adopting the ACC program, the Board committed to conduct a comprehensive midterm review (MTR), which includes evaluating the appropriateness of the ZEV targets as well as collaborating on a second Technical Assessment Report (TAR 2.0) with U.S. EPA and NHTSA for the GHG standards. The Draft (Joint) Technical Assessment Report must be published for public comment no later than November 15, 2017. U.S. EPA must make a final decision on the federal standards, no later than April 1, 2018. ARB's technical assessment to be captured in the MTR will occur concurrently with U.S. EPA's timeline set out above.

Specifically, ARB's MTR will include the following elements:

- GHG: In coordination with U.S. EPA and NHTSA, evaluating the appropriateness of the adopted 2022 through 2025 model year GHG standards for light- and medium-duty vehicles and whether the standards should be made more or less stringent;

- ZEV: Assessing market penetration and response to transitional zero-emission vehicles (TZEV) and ZEVs, and evaluating the standards adopted by the Board;

- Particulate Matter (PM) emissions: Assessing laboratory measurement capability for sub-1 milligram per mile (mg/mi) PM levels and evaluating the 1 mg/mi PM tailpipe standard to begin in the 2025 model year, including whether the standard should be applied to earlier model years.

ARB staff will provide an oral presentation at the meeting that provides an update on the progress that has been made to date to address the Board's commitment. This is an informational item only. No Board action is anticipated.

Interested members of the public may present comments orally or in writing at the meeting and may provide comments by postal mail or by electronic submittal before the meeting. To be considered by the Board, written comments not physically submitted at the meeting, must be received **no later than 12:00 noon, October 23, 2013,** and addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

You can sign up online in advance to speak at the Board meeting when you submit an electronic board item comment. For more information go to: http://www.arb.ca.gov/board/online-signup.htm.

Please note that under the California Public Records Act (Government Code section 6250 et seq.), your written and verbal comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

ARB requests that written and email statements on this item be filed at least 10 days prior to the meeting so that ARB staff and Board members have additional time to consider each comment. Further inquiries regarding the ZEV component of the update should be directed to Ms. Anna Wong, Air Resources Engineer, at (916) 323-2410. Further inquiries regarding the LEV III component of the update should be directed to Ms. Sarah Carter, Staff Air Pollution Specialist, at (626) 575-6845.

SPECIAL ACCOMMODATION REQUEST

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CALIFORNIA AIR RESOURCES BOARD

/s/
Richard W. Corey
Executive Officer

Date: September 20, 2013

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website at www.arb.ca.gov.

TITLE 13. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER MINOR MODIFICATIONS TO THE ZERO EMISSION VEHICLE REGULATION

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider minor proposed amendments to the California Zero Emission Vehicle (ZEV) regulation.

DATE: **October 24, 2013**

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., **October 24, 2013**, and may continue at 8:30 a.m., on **October 25, 2013**. This item may not be considered until October 25, 2013. Please consult the agenda for the hearing, which will be available at least 10 days before October 24, 2013, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW PURSUANT TO GOVERNMENT CODE 11346.5(a)(3)

Sections Affected: Proposed amendments to California Code of Regulations, title 13, sections 1962.1 and 1962.2, and proposed amendments to "California Exhaust Emission Standards and Test Procedures for 2009 through 2017 Model Zero-Emission Vehicles and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck, and Medium-Duty Vehicle Classes", as adopted December 17, 2008, and as last amended December 6, 2012, which is incorporated by reference in section 1962.1, title 13, California Code of Regulations, and "California Exhaust Emission Standards and Test Procedures for 2018 and Subsequent Model Zero-Emission Vehicles and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck, and Medium-Duty Vehicle Classes," as adopted March 22, 2012, and as last amended December 6, 2012, which is hereby incorporated by reference in section 1962.2, title 13, California Code of Regulations.

Background and Effect of the Proposed Rulemaking:

In January 2012, the ARB approved the Advanced Clean Cars program, which included increased ZEV requirements through 2025 model year, and the next generation of light duty greenhouse gas (GHG) and criteria pollutant emission standards (LEV III). This historic program combined the control of smog-causing pollutants and GHG emissions

into a single coordinated package of requirements for model years 2017 through 2025 and assured the development of environmentally superior cars that will continue to deliver the performance, utility, and safety vehicle owners have come to expect. The Board approved subsequent minor amendments to the Advanced Clean Car program in November 2012, and a final EPA waiver was granted in January 2013.

Due to a compressed schedule, staff was not able to make additional minor modifications before the regulation was finalized in December 2012. Staff is returning to the Board with minor amendments to effectuate an agreement between the Section 177 states[1] and regulated manufacturers, add provisions to ensure ZEVs are delivered for sale in California every year, modify the fast refueling definition, and add conforming and clarifying language where needed.

Objectives and Benefits of the Proposed Regulation:

Staff's proposal addresses four minor problems, while still maintaining the Board's commitment to a strengthened ZEV regulation:

1) Adjusts the optional Section 177 state compliance path as committed to by the Section 177 states and the manufacturers.

In 2012, the Board approved a new optional provision which allowed manufacturers to produce extra ZEVs in the section 177 states prior to model year 2018. In exchange for these extra ZEVs, manufacturers gain the ability to pool credits across state lines within and between two Regional pools. Additionally, manufacturers would also be allowed to comply with a reduced transitional zero emission vehicles (TZEV) and ZEV portion of their requirement in certain model years. This provision was put in place to smooth the transition into 2018 and subsequent model year requirements, and ensure ZEVs were placed in the section 177 states prior to 2018 model year. Manufacturers and the section 177 states helped draft language, which was finalized in 2012.

Since adoption, manufacturers and Section 177 states have continued discussions surrounding this provision, and have requested a number of changes to ensure its success. Staff is proposing to exclude the use of transportation system credits for meeting the additional ZEV percentages in each of the Section 177 states in model years 2016 and 2017. This modification will help ensure those additional percentages are met with credits from actual vehicles. Staff is also proposing to allow manufacturers on the optional compliance path to trade and transfer 2012 through 2017 model year ZEV and TZEV credits within and between each Regional pool[2]. This means that, for example, a manufacturer could use 2012 through 2015 model year credits to meet a 2015 model year obligation.

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[1]Section 177 of the federal Clean Air Act allows other states to adopt California motor vehicle emission standards including the ZEV regulation.

[2] Two Regional pools were created for the purpose of this provision: the West Region pool and East Region Pool. States west of the Mississippi River, excluding California, make up the West Region pool, and states east of the Mississippi River make up the East Region pool.

Staff is also proposing to remove the requirement to provide vehicle identification numbers (VIN) for TZEVs prior to 2018 model year and substitute a requirement that manufacturers provide VINs for ZEVs and TZEVs upon request. Lastly, staff is proposing to simplify the provision specifying what happens when a manufacturer elects the optional Section 177 state compliance path, but fails to comply with any or all of the requirements.

2) Maintains a minimum ZEV credit requirement, regardless of model year and use of non-ZEV credits earned in the regulation.

Various caps on use of credits from special flexibility provisions have been put in place over iterations of the regulation to ensure manufacturers are still required to produce ZEVs. However, staff found that there was no clear direction for how to apply these caps in combination to meet ZEV requirements. For example, a large volume manufacturer is subject to the following caps when meeting its 2018 model year minimum ZEV requirement:

- Extended Range Battery Electric Vehicle (BEVx) Credits: No more than 50% of minimum ZEV requirement[3]
- GHG-ZEV Over-compliance Credits: No more than 50% of minimum ZEV requirement[4]
- Transportation System Credits from ZEVs: No more than 10% of minimum ZEV requirement

Staff is now proposing an overall 50% cap when a manufacturer uses credits (other than pure ZEV credits) in combination to meet its minimum ZEV requirement in any given model year.

3) Modify fast refueling definition to exclude range accumulation through battery exchange.

Adopted in 2001, ZEVs with the ability to refuel to 95% of full capacity within 15 minutes are allowed to earn more credit, under the Type IV and Type V ZEV definitions. Below is a summary of each ZEV type definition and credit level.

	Definition	**2012-2014 Credit Level**	**2015-2017 Credit Level**
Type IV ZEV	200+ mile range, and fast refueling capable	5	5
Type V ZEV	300+ mile range, and fast refueling capable	7	9

[3] CCR, Title 13, Section 1962.2(g)(6)(B)
[4] CCR, Title 13, Section 1962.2(g)(6)(C)3.

Some BEVs have been qualifying under the fast refueling definition by means of battery exchange. However, it has not been publically demonstrated that battery exchanges have occurred on the vehicles earning credits. Though staff does recognize the potential for a battery exchange to help market the vehicle, other vehicles earning Type IV and V ZEV credit depend on fast refueling for vehicle operation and success. Staff is proposing to remove battery exchange from qualifying under the fast refueling definition, starting in 2015 model year.

Resulting from the amendments proposed, manufacturers will benefit from greater flexibility in complying with the regulations, while the Board will benefit from a maintained ZEV credit requirement each year. Staff is also proposing minor clarifying, grammatical, and numbering corrections.

DETERMINATION OF INCONSISTENCY AND INCOMPATIBILITY WITH EXISTING STATE REGULATIONS

During the process of developing the proposed regulatory action, ARB has conducted a search of any similar regulations on this topic and has concluded that these regulations are neither inconsistent nor incompatible with existing state regulations.

MANDATED BY FEDERAL LAW OR COMPARABLE FEDERAL REGULATIONS

This regulation is not mandated by federal law or regulations.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal, and all information upon which the proposed regulation is based. The report is entitled: "2013 Minor Modifications to the Zero Emission Vehicle Regulation".

Copies of the ISOR and the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, may be accessed on ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990, on September 4, 2013.

Final Statement of Reasons Availability

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on ARB's website listed below.

Agency Contact Persons

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Anna Wong, Air Pollution Specialist, (916) 323-2410 or Elise Keddie, ZEV Implementation Section Manager, (916) 323-8974.

Further, the agency representative and designated back-up contact persons, to whom non-substantive inquiries concerning the proposed administrative action may be directed are Amy Whiting, Regulations Coordinator, (916) 322-6533. The Board staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

Internet Access

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at http://www.arb.ca.gov/regact/2013/zev2013/zev2013.htm

DISCLOSURES REGARDING THE PROPOSED REGULATION

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Fiscal Impact / Local Mandate

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would not create costs or savings to any State agency or in federal funding to the State, costs or mandate to any local agency or school district, whether or not reimbursable by the State pursuant to Government Code, title 2, division 4, part 7 (commencing with section 17500), or other nondiscretionary cost or savings to State or local agencies.

Significant Statewide Adverse Economic Impact Directly Affecting Business, Including Ability To Compete

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons.

Cost Impacts on Representative Private Persons or Businesses

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses. The ARB is not aware of any

cost impacts that a representative private person or business would necessarily incur in reasonable compliance with the proposed action.

Statement of the Results of the Economic Impact Assessment Prepared Pursuant to Government Code Sec. 11346.3(b)

Effect on Jobs/Businesses:

The Executive Officer has determined that the proposed regulatory action would not affect the creation or elimination of jobs within the State of California, the creation of new businesses or elimination of existing businesses within the State of California, or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the Economic Impact Analysis in the ISOR.

Benefits of the Proposed Regulation:

The objective of the proposed amendments is to make minor amendments to effectuate an agreement between the Section 177 states and regulated manufacturers, add provisions to ensure ZEVs are delivered for sale in California every year, modify the fast refueling definition, and add conforming and clarifying language where needed. Further, compliance with ZEV regulation will create a positive impact on emission benefits, as a result, benefits the air quality of the state's environment.

A summary of these benefits is provided, please refer to "Objectives and Benefits", under the Informative Digest of Proposed Action and Policy Statement Overview Pursuant to Government Code 11346.5(a)(3) discussion on page 2.

EFFECT ON SMALL BUSINESS

The Executive Officer has also determined, pursuant to California Code of Regulations, title 1, section 4, that the proposed regulatory action would not affect small businesses because small businesses are not regulated parties under these regulations.

HOUSING COSTS

The Executive Officer has also made the initial determination that the proposed regulatory action will not have a significant effect on housing costs.

BUSINESS REPORT

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

ALTERNATIVES

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board, or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed, or would be as effective and less burdensome to affected private persons than the proposed action, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provisions of law.

ENVIRONMENTAL ANALYSIS

In accordance with ARB's certified regulatory program, California Code of Regulations, title 17, sections 60006 through 60007, and the California Environmental Quality Act, Public Resources Code section 21080.5, ARB has conducted an analysis of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulatory action. The environmental analysis of the proposed regulatory action can be found in Chapter IV of the ISOR.

WRITTEN COMMENT PERIOD AND SUBMITTAL OF COMMENTS

Interested members of the public may present comments orally or in writing at the meeting and may provide comments by postal mail or by electronic submittal before the meeting. The public comment period for this regulatory action will begin on September 9, 2013. To be considered by the Board, written comments not physically submitted at the meeting, must be submitted on or after September 9, 2013 and received **no later than 12:00 noon on October 23, 2013**, and must be addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

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Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

ARB requests that written and email statements on this item be filed at least 10 days prior to the hearing so that ARB staff and Board members have additional time to

consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

Additionally, the Board requests but does not require that persons who submit written comments to the Board reference the title of the proposal in their comments to facilitate review.

AUTHORITY AND REFERENCE

This regulatory action is proposed under the authority granted in Health and Safety Code, sections 39600, 39601, 43013, 43018, 43101, 43104 and 43105. This action is proposed to implement, interpret, and make specific sections 38562, 39002, 39003, 39667, 43000, 43009.5, 43013, 43018, 43018.5, 43100, 43101, 43101.5, 43102, 43104, 43105, 43106, 43204, 43205, 43205.5 and 43206.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, Government Code, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340).

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice and that the regulatory language as modified could result from the proposed regulatory action; in such event, the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15-days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format or another language; or
- A disability-related reasonable accommodation.

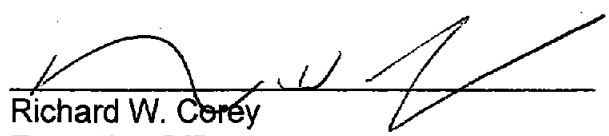
To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at 916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia.
- Documentos disponibles en un formato alterno u otro idioma.
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD



Richard W. Corey
Executive Officer

Date: August 27, 2013

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website at www.arb.ca.gov.

State of California

AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

2013 MINOR MODIFICATIONS TO THE ZERO EMISSION VEHICLE REGULATION

Date of Release: **September 4, 2013**

Scheduled for Consideration: **October 24 and 25, 2013**

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Table of Acronyms

ACC.....Advanced Clean Car
ARB .....California Air Resources Board or The Board
BEV .....Battery Electric Vehicle
BEVx .....Range Extended Battery Electric Vehicle
CAFE.....Corporate Average Fuel Economy
CEQA .....California Environmental Quality Act
EA.....Environmental Assessment
FCV .....Fuel Cell Electric Vehicle
FSOR .....Final Statement of Reasons
GHG .....Greenhouse Gas
ISOR .....Initial Statement of Reasons
IVM.....Intermediate Vehicle Manufacturer
LDT.....Light-duty Trucks loaded vehicle weight up to 8500 pounds
LEV I .....First generation Low Emission Vehicle program, adopted in a 1990-1991 rulemaking, and generally applicable in the 1994-2003 model years
LEV II .....Second generation Low Emission Vehicle program, adopted in a 1998 -1999 rulemaking, and generally applicable in the 2004 and subsequent model years
LEV III.....Third generation Low Emission Vehicle program (criteria pollutant and greenhouse gas emission fleet standards), adopted in 2012, and generally applicable to 2015 and subsequent model years for Criteria Pollutants, and applicable to 2017 and subsequent model years for Greenhouse Gases.
MDV .....Medium Duty Vehicle
MOA .....Memorandum of Agreement
NHTSA .....National Highway Traffic Safety Administration
NOx.....Oxides of Nitrogen
PC .....Passenger Car
PHEV .....Plug-in Hybrid-Electric Vehicle
Type III .....ZEV, range of 100 or more miles plus fast refueling, or 200 miles
Type IV .....ZEV, range of 200 or more miles plus fast refueling
Type V.....ZEV, range of 300 or more miles plus fast refueling
TZEV .....Transitional Zero Emission Vehicle, typically a plug-in hybrid electric vehicle
U.S. EPA .....United States Environmental Protection Agency
VMT.....Vehicle Miles Traveled
ZEV .....Zero Emission Vehicle

I. Introduction and Background

A. Introduction

In 1990, the California Air Resources Board (ARB or the Board) adopted an ambitious program to dramatically reduce the environmental impact of light-duty vehicles through the gradual introduction of zero emission vehicles (ZEV) into the California fleet as part of the Low Emission Vehicle (LEV I) regulation. The ZEV regulation, which affects passenger cars (PC) and light-duty trucks (LDT), has been adjusted six times since its inception - in 1996, 1998, 2001, 2003, 2008, and 2012 to reflect the pace of ZEV development and the emergence of new ZEV and ZEV-like technologies. Throughout these adjustments the fundamental goal of the program has not changed: California remains committed to the commercialization of ZEV technologies.

California's strong commitment to the ZEV program reflects the essential need for ZEV technology in order to achieve the State's public health protection goals, including criteria pollutant and long-term climate change emission reductions. Health-based state and federal air quality standards continue to be exceeded in regions throughout California. Both the greater Los Angeles region and the San Joaquin Valley are classified by the United States Environmental Protection Agency (U.S. EPA) as "extreme" ozone non-attainment areas. For example, to meet the necessary ozone levels in San Joaquin Valley, emission reductions needed are equal to eliminating all oxides of nitrogen (NOx) from the regional light duty fleet.

Former California Governor Arnold Schwarzenegger enacted Executive Order S-03-05, requiring a reduction in state-wide GHG emissions to 80-percent below 1990 levels by 2050. According to staff's analysis, pure ZEVs would need to reach nearly 100 percent of new vehicle sales between 2040 and 2050, in order to meet the 80% reduction goal.

ZEVs remain critical in obtaining California's long term air quality and climate change goals as reinforced by Governor Jerry Brown's Executive Order B-16-2012[1], which calls for collective action to support ZEV commercialization in California.

Staff's proposal will help ensure a strong ZEV regulation remains in place in California and all Section 177 states[2], while allowing appropriate compliance flexibility where needed.

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[1] The full text for Executive Order B-16-2012 can be accessed at the following website: http://www.gov.ca.gov/news.php?id=17472

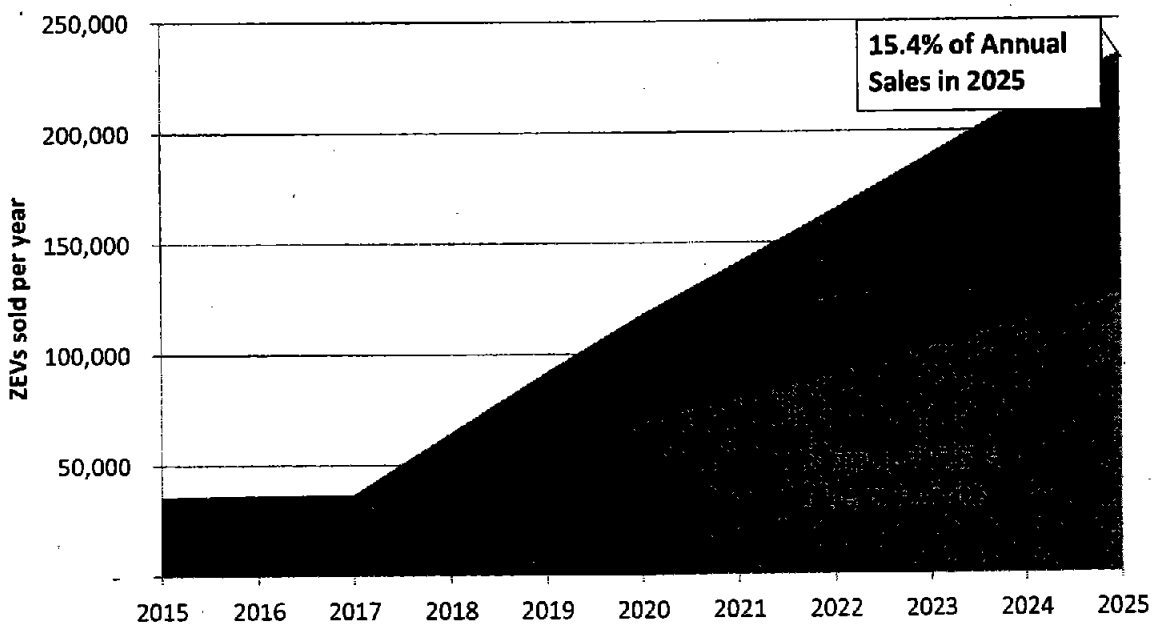
[2] Section 177 of the federal Clean Air Act allows other states to adopt California motor vehicle emission standards including the ZEV regulation.

B. Background and Current ZEV Requirements

In January 2012, the ARB adopted the Advanced Clean Car (ACC) program, which included increased ZEV requirements through 2025 model year, and the next generation of light duty GHG and criteria pollutant emission standards (LEV III). This historic program combined the control of smog-causing pollutants and greenhouse gas emissions into a single coordinated package of requirements for model years 2017 through 2025 and assured the development of environmentally superior cars that will continue to deliver the performance, utility, and safety vehicle owners have come to expect. The Board adopted subsequent minor amendments to the ACC program in November 2012, and a final EPA waiver was granted in January 2013.

The current ZEV requirements for 2018 and subsequent model years focus the program on ZEVs (battery electric vehicles or BEVs, and fuel cell vehicles or FCVs) and transitional ZEVs (TZEVs, plug-in hybrid electric vehicles or PHEVs). By 2025, compliance with the requirements will likely result in more than 15% of new sales to be ZEVs and TZEVs. Graph 1 below shows the likely trajectory of those sales.

Graph 1: Likely ZEV Regulation Compliance for 2015 through 2025[3]



[3] Requirements are based on a number of credits a manufacturer must produce in a given year. Credits are awarded based on the vehicle's zero emission range, with the high range vehicle earning the most amount of credit. For more information on the development of this compliance scenario, see ARB's 2012 ZEV ISOR: http://www.arb.ca.gov/regact/2012/zev2012/zevisor.pdf.

Currently, BMW, Chrysler, Ford, General Motors, Honda, Hyundai, Kia, Mazda, Mercedes-Benz, Nissan, Toyota, and Volkswagen are required to produce pure ZEVs to comply with the 2018 and subsequent model year requirements. Four additional manufacturers (Subaru, Volvo, Jaguar Land Rover, and Mitsubishi) are also required to comply with the ZEV requirements, but would be allowed to meet their obligation completely with TZEVs.

Due to a compressed schedule, staff was not able to make additional minor modifications before the regulation was finalized in December 2012. Staff is returning to the Board with minor amendments to effectuate an agreement between the Section 177 states and regulated manufacturers, add provisions to ensure ZEVs are delivered for sale in California every year, removing battery swapping from fast refueling definition, and add conforming and clarifying language where needed.

C. Public Process for ZEV Regulation Development

Beginning in May 2013, ARB staff conducted one public workshop to engage stakeholders and obtain input on the proposed regulatory amendments. These stakeholders primarily included representatives from regulated and non-regulated manufacturers, vehicle component suppliers, and environmental advocates. This workshop was held at ARB offices in Sacramento and broadcast via webcast. The announcements and materials for this workshop were posted on ARB's website and distributed through a list serve that included over 14,500 recipients. In an effort to build consensus and minimize areas of disagreement, staff worked with the Section 177 states and manufacturers on proposed language presented at the workshop. Staff received comments from multiple Section 177 states in regard to language presented at the workshop which allowed the states to request vehicle identification numbers for ZEVs and TZEVs placed on the optional Section 177 state compliance path[4]. Staff agreed with the Section 177 state comments and incorporated the recommended language.

The materials presented at the workshop are available on ARB's ZEV program website at http://www.arb.ca.gov/msprog/zevprog/zevprog.htm.

[4] Explained further on page 8, the optional Section 177 state compliance path allows manufacturers to produce ZEVs prior to model year 2018 for lesser ZEV and TZEV requirements in later model years.

II. Statement of Reasons

This section provides a description of public problem, administrative circumstances the proposal is intended to address, proposed solutions to the public problem, and rationale supporting the proposed solutions.

Staff's proposal addresses four minor problems, while still maintaining the Board's commitment to a strengthened ZEV regulation:

1) Adjusts the optional Section 177 state compliance path as committed to by the Section 177 states and the manufacturers;

2) Maintains a minimum ZEV credit requirement, regardless of model year and use of non-ZEV credits earned in the regulation;

3) Disallows battery exchange to qualify under the fast refueling definition for Type IV and V ZEVs; and,

4) Corrects grammatical and California Code of Regulation (CCR) reference errors.

Due to a compressed rulemaking schedule in 2012, staff was unable to propose changes prior to the regulations being finalized on December 31, 2012. However, in meetings with affected stakeholders throughout 2012, staff committed to making necessary changes to ensure all minor issues were addressed, as soon as possible. The current proposed modifications, as discussed in length below, make necessary corrections and additions while maintaining the January 2012 Board direction.

III. Summary of Proposed Action

The amendments identified in this section represent the most significant changes being proposed. Additional minor proposed amendments and the related rationale can be found below in Section VII.

The following sections more fully describe each of the major proposed amendments and the rationale for the proposed change.

A. Optional Section 177 State Compliance Path

Section 177 of the federal Clean Air Act[5] allows other states to adopt California motor vehicle emission standards including the ZEV regulation. Currently, there are 10 states which have adopted the California ZEV regulation: Connecticut, Maine, Maryland, Massachusetts, New Jersey, New Mexico, New York, Oregon, Rhode Island, and Vermont (hereafter, referred to as Section 177 states). During the development of the 2012 ACC rulemaking, manufacturers pushed to extend the travel provision[6] for BEVs through 2017 model year. However, the Section 177 states wanted to guarantee pure ZEV placement in their states prior to 2018 model year to maintain momentum on incentive support and infrastructure development. The manufacturers and Section 177 states went into negotiations in the fall of 2011, and developed an optional compliance path. 2012, the Board adopted a new optional provision which allowed manufacturers to produce extra ZEVs in the Section 177 states prior to model year 2018. The additional percentages are equal to about 5,000 ZEVs[7] being placed in total in the Section 177 states.[8]

In exchange for these extra ZEVs, manufacturers gain the ability to pool credits across state lines within and between two regional pools. Additionally, manufacturers would also be allowed to comply with a reduced TZEV and ZEV portion of their requirement in certain model years. This provision was put in place to smooth the transition into 2018 and subsequent model year requirements, and ensure ZEVs were placed in the Section 177 states prior to 2018 model year. Manufacturers and the Section 177 states helped draft language, which was finalized in 2012.

Since adoption, manufacturers and Section 177 states have continued discussions surrounding this provision, and have requested a number of changes to ensure its success. Each of these changes is discussed below.

1. Use of Transportation System Credits

Transportation system credits are earned for each ZEV and/or TZEV a manufacturer places in a car-share program. These are extra credits that a manufacturer can also use to meet a portion of their ZEV requirements. Staff proposes to exclude transportation system credits from meeting the additional

[5] United States Code, title 42, section 7507

[6] The travel provision (CCR 1962.1(d)(5)(E)) allows manufacturers to count ZEVs placed in California toward their California requirement and Section 177 state requirements, without having to place additional ZEVs in the Section 177 states.

[7] Assumes all manufacturers take optional Section 177 state compliance path, and comply with both FCVs and BEVs.

[8] As of August 2013, all Section 177 states have not adopted the 2012 amendments due to political constraints.

ZEV percentages in each of the Section 177 states in model years 2016 and 2017. Though ZEVs intended for compliance with the optional Section 177 percentages may be placed in transportation systems, the transportation system credits may not go toward meeting the additional percentages. The intent of the additional ZEV percentages in this optional path is to ensure actual ZEVs are delivered in the Section 177 states prior to 2018 model year. This modification helps ensure those additional percentages are met with credits from actual vehicles.

2. **Pooling**

Staff proposes that manufacturers on the optional compliance path may trade and transfer 2012 through 2017 model year ZEV and TZEV credits within and between each Regional pool[9]. Previously, the language only allowed trading and transferring of credits within and between each Regional pool in a single model year. For example, a manufacturer would have only been able to pool 2015 model year credits to meet a 2015 model year obligation. Manufacturers and Section 177 states discussed the issue and decided a better approach that would likely result in more manufacturers taking this optional path would be to allow pooling of multiple model years of credits. This means that, for example, a manufacturer could use 2012 through 2015 model year credits to meet a 2015 model year obligation.

3. **Intermediate Volume Manufacturers**

Staff is adding a table which clarifies how the intermediate volume manufacturers are to comply with the optional compliance path. The new table does not change the intent of the original language. Intermediate volume manufacturers interested in this path are to meet the same additional ZEV percentages available to the large volume manufacturers, but are allowed to meet a reduced requirement that still may be met with partial zero emission vehicles (PZEV)[10].

4. **Reporting Requirements**

Staff proposes to remove the requirement to provide vehicle identification numbers (VIN) for TZEVs prior to 2018 model year. Manufacturers expressed concern over the sheer quantity of VINs required to be reported, and the usefulness of such data. The Section 177 states still wanted a way to track

[9] Two Regional pools were created for the purpose of this provision: the West Region pool and East Region Pool. States west of the Mississippi River, excluding California, make up the West Region pool, and states east of the Mississippi River make up the East Region pool.

[10] PZEVs are conventional gasoline vehicles that are certified to the super-ultra-low-emission vehicle standard, and have an extended 150,000 mi/15 year warranty. PZEVs will be phased out of the ZEV regulation after 2017 model year.

vehicles placed and pooled. Therefore, a provision is being proposed to require manufacturers to provide VINs for ZEVs and TZEVs upon request. This provision applies to ZEV and TZEV credits being used for compliance on the optional path and those credits being pooled.

5. Failure to Comply

Staff is proposing to simplify the provision which specifies what happens if a manufacturer elects the optional Section 177 state compliance path, but fails to comply with any or all of the requirements. Currently, the language voids all past credit transactions if a manufacturer fails to comply in any model year with the optional compliance path. As the Section 177 states and manufacturers discussed this provision, it became clear that retracing credits back to the originator might be unreasonably difficult and complicated. Therefore, language has been added to forbid all future transactions of credits within or between the Regional pools in cases of non-compliance.

B. Maintaining a Minimum ZEV Credit Requirement

As currently written, manufacturers may earn various types of credits to comply with the regulation. Caps on certain credit uses were put in place over iterations of the regulation to ensure manufacturers would still be required to produce ZEVs. However, staff found that there was no clear direction for how to apply credit caps in combination to meet ZEV requirements. For example, a large volume manufacturer is subject to the following caps when meeting its 2018 model year minimum ZEV requirement:

- BEVx Credits: No more than 50% of minimum ZEV requirement[11]
- GHG-ZEV Over-compliance Credits: No more than 50% of minimum ZEV requirement[12]
- Transportation System Credits from ZEVs: No more than 10% of minimum ZEV requirement

The regulatory language did not specify how these non-pure ZEV credits could be used in combination to meet a manufacturer's ZEV requirement. Generally as new credit mechanisms were adopted, the Board would also adopt a cap on the non-ZEV credits to ensure ZEVs were still produced each year. Therefore, staff is now proposing an overall rule that non-pure ZEV credits may only be used to meet 50% of a manufacturer's minimum ZEV requirement in a given model year. This will not change any of the previously set individual caps. For example, manufacturers will still be only allowed to meet 10% of their minimum ZEV requirement with transportation system

[11] CCR, Title 13, Section 1962.2(g)(6)(B)
[12] CCR, Title 13, Section 1962.2(g)(6)(C)3.

credits from ZEVs. Also, manufacturers may still earn these credits, as allowed by each provision, and bank the credits (if allowed[13]) for use in future model years.

C. Fast Refueling Definition

Adopted in 2001, ZEVs with the ability to refuel to 95% of full capacity within 15 minutes are allowed to earn more credit, under the Type IV and Type V ZEV definitions. Below is a summary of each ZEV type definition and credit level.

	Definition	2012-2014 Credit Level	2015-2017 Credit Level
Type IV ZEV	200+ mile range, and fast refueling capable	5	5
Type V ZEV	300+ mile range, and fast refueling capable	7	9

Some BEVs have been qualifying under the fast refueling definition by means of battery exchange. However, it has not been publically demonstrated that battery exchanges have occurred on the vehicles earning credits. Though staff does recognize the potential for a battery exchange to help market the vehicle, other vehicles earning Type IV and V ZEV credit depend on fast refueling for vehicle operation and success. Staff is proposing to remove battery exchange from qualifying under the fast refueling definition, starting in 2015 model year.

Hydrogen fast refueling capable Type V ZEVs will still earn 9 credits each in model years 2015 through 2017 upon placement in service. Staff believes it is important to maintain the difference in credit level between the two ZEV technologies to ensure appropriate incentives are in-place to support hydrogen technologies as infrastructure ramps up through 2017. Hydrogen remains a long-term solution for all vehicle classes, and is essential for meeting California's long-term air quality and GHG reduction goals.

Additional minor modifications are discussed in Section VII of this ISOR.

[13] Per section 1962.2(g)(6)(C)3. GHG-ZEV Over-Compliance credits are not allowed to be banked for use in any future model year.

IV. Environmental Impacts Analysis

A. Introduction

This chapter provides an environmental analysis for the proposed amendments. Based on ARB's review, staff has determined that implementing the proposed amendments to the ZEV regulation would not result in any potentially significant adverse impacts on the environment. This analysis provides the basis for reaching this conclusion. This section of the Staff Report also discusses environmental benefits expected from implementing the proposed regulation.

B. Environmental Review Process

ARB is the lead agency for the proposed amendments and has prepared this environmental analysis pursuant to its regulatory program certified by the Secretary of the Natural Resources Agency (14 CCR 15251(d); 17 CCR 60005-60007). In accordance with Public Resources Code section 21080.5 of the California Environmental Quality Act (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). ARB has prepared this environmental analysis (EA) to assess the potential for significant adverse and beneficial environmental impacts associated with the proposed amendments, as required by ARB's certified regulatory program (17 CCR 60005(b)). The resource areas from the CEQA Guidelines Environmental Checklist were used as a framework for assessing the potential for significant impacts (17 CCR 60005(b)).

If comments received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in the Final Statement of Reasons (FSOR) prepared for the regulation. The final decision-maker will approve the written responses to comments prior to taking final action on the proposed regulation (17 CCR 60007(a)). If the amendments are adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection (17 CCR 60007(b)).

C. Prior Environmental Analysis

The ZEV regulation was first adopted in 1990 as part of the Low Emission Vehicle (LEV) Program, and has been modified several times over the years. In January 2012, the Air Resources Board approved the "ACC Program" – a single, coordinated package of regulatory actions for passenger vehicles that provides a new emissions-control program by combining the control of smog-causing pollutants and greenhouse gas emissions. The approved ACC Program regulatory package also included amendments to the ZEV regulation.

An environmental analysis (*Environmental Analysis for the ACC Program* or "ACC EA") was prepared for the ZEV regulations, as part of the ACC Program, and released for public review and comment in December 2011. The ACC EA concluded that the compliance responses to the proposed ACC Program would result in beneficial impacts to air quality through reductions in emissions, including GHG, criteria air pollutants and precursors (CAP), and toxic air contaminants (TAC). It further concluded that the proposed ACC Program would result in less-than-significant impacts to agricultural and forest resources, greenhouse gases, land use, minerals, population and housing, public services, and recreation.

The ACC EA also concluded there could be potentially significant adverse impacts to aesthetics, air quality and noise (both related to construction), biological resources, cultural resources, geology/soils, hazards/hazardous materials (related to accidental releases), hydrology/water quality, traffic and utilities due to the construction and operation of new battery manufacturing facilities, as needed to achieve compliance with activities related to the ZEV regulation.

The ACC EA determined that construction and operation of new manufacturing plants for producing propulsion batteries and fuel cells, though likely to occur in areas with consistent zoning, could result in potentially significant adverse impacts to the ten resource areas listed above. The ACC EA identified mitigation measures to reduce these potentially significant impacts to a less-than-significant level; however, it was determined that the authority to determine project-level impacts and require project-level mitigation lies with the local lead agency for individual projects, which is beyond ARB's authority. Since the ACC EA programmatic analysis could not determine project-specific details of mitigation, there is an inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts. Therefore, the ACC EA took a conservative approach in its post-mitigation significance conclusion and disclosed, for CEQA compliance purposes, that the potentially significant impacts to these resource areas resulting from the construction and operation of new manufacturing plants may be significant and unavoidable.

The Board, after consideration of the entire record, including the information contained in the EA, public testimony, written comments received, and the written responses to comments, adopted written findings for each significant adverse impact identified in the ACC EA in *Resolution 12-21* adopting the ACC Program regulations.

D. Proposed Regulation

1. Description

ARB staff is proposing to make amendments to the existing ZEV regulation. As described in Chapter III of this Staff Report, the proposed amendments would amount to minor modifications including the following:

- Adjusting the optional Section 177 state compliance path provision
- Defining how caps apply to a manufacturer's requirement
- Disallows battery swapping to qualify under the fast refueling definition for Type IV and V ZEVs

2. Methods of Compliance

The proposed amendments include provisions that are mostly administrative and procedural in nature that will clarify definitions and regulatory language, close loopholes, correct references to other sections in the CCR, add the right to request VINs from vehicle manufacturers, and correcting grammatical errors. In addition, other, more extensive, provisions are also included that will allow 2012 through 2017 model year TZEV and ZEV credits to be pooled under the optional Section 177 state compliance path, place a new cap on the number of non-ZEV credits a manufacturer can use towards meeting its ZEV requirement, and disallow the fast refueling definition to be met through battery exchange. To ease compliance with the more substantial changes proposed, the affected community would gain flexibility in complying with Section 177 state ZEV requirements in 2015 and subsequent model years and be required to comply with credits from production of ZEVs in 2018 and subsequent model years. The new application of caps will likely result in the same number of vehicles. Non-ZEV credits that are more heavily capped will be banked and used in later years for compliance.

E. Environmental Impacts

1. Beneficial Impacts

The proposed amendments do not change the percentages of ZEVs or equivalent number of credits within the current ZEV regulation, but will merely simplify implementation of and compliance with the ZEV regulation as it was originally intended. These modifications do not generate any additional emission reductions, but rather seek to ensure emission reductions occur as planned, by facilitating compliance and encouraging manufacturers to produce more ZEVs, thus increasing available ZEV technology in California.

2. Resource Areas with No Impacts

ARB has reviewed the proposed amendments and concludes that the amendments could not possibly result in any significant or potentially significant adverse impacts on the environment because compliance with the proposed regulation would not result in any physical change to the existing environment. Further, compliance with the proposed amendments does not include any activity that would involve or affect any of the environmental resource areas because they do not require any action that could possibly affect these resources.

The proposed amendments would include activities that are merely administrative in nature and would not affect the stringency of the current provisions within the ZEV regulation. These modifications are necessary to ensure that the regulatory provisions become more efficient and to more accurately align with the original intent of the regulation. This is achieved by providing clarifying language and definitions, and closing existing loopholes. These modifications will help make sure that this regulation will work in a more seamless manner.

No discussion of alternatives or mitigation measures is necessary because no significant adverse environmental impacts were identified.

V. ENVIRONMENTAL JUSTICE

"Environmental Justice" is defined as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies (Government Code §65040.12(c).

Staff does not believe that this proposal will have any adverse environmental justice impacts because the stringency of ZEV regulation is not affected by the proposed changes to the regulations. The proposed changes are limited to the correction of errors and providing clarification to the current regulations, there will be no increase in criteria pollutants in California due to mix shifting of vehicles between California and other states.

VI. ECONOMIC IMPACTS

Staff does not expect additional costs due to these amendments. The proposed amendments impact only the approximately sixteen vehicle manufacturers subject to the ZEV regulations, most of which are headquartered outside of California. Numerous flexibilities exist in the ZEV regulation, and are continued in this rulemaking. It is difficult to predict how each manufacturer will respond to the various flexibilities being modified in staff's proposal given the continuing evolution of the ZEV market. However, in aggregate, based on discussions with stakeholders, staff does not expect that these changes would significantly alter the number of ZEVs a manufacturer would need to produce in any model year. Staff also believes there will be little to no impact to consumers and jobs in California.

Modifications in this rulemaking are corrective, clarifying, or updating in nature and are intended to ensure the emissions benefits expected from the program are achieved. The stringency of the programs remains unchanged. The modifications related to the Section 177 state optional compliance path do not affect California, only compliance in the Section 177 states. Thus, this amendment formalizes ARB's commitment to this provision but, like the other minor revisions, does not introduce any new economic impacts.

There will be no fiscal impacts to the State from the proposed amendments, either in terms of tax revenue or personnel requirements. These amendments are not expected to change vehicle prices in a way that would alter vehicle purchase decisions. The inclusion of an alternative compliance option or an overall credit cap does not substantially increase the volume of data to review or the enforcement burden to the ARB that would justify hiring additional staff.

Alternatives

1. Evaluation of alternatives considered and reasons for rejecting them

Staff considered not making the proposed changes to the current ZEV regulation. That alternative would only allow vehicle manufacturers who choose the optional compliance path to pool ZEV and TZEV credits for each model year, which would have been more restrictive. Additionally, not placing an overall cap on the use of non-ZEV credits might have resulted in no ZEVs produced in 2018 and 2019 in California, which is not in line with the Board's direction in Resolution 12-11. Also, without clarifying the fast refueling definition, some ZEVs would continue to earn more credits than appropriate in 2015 through 2017 model years, possibly resulting in fewer overall ZEVs.

This alternative was rejected because vehicle manufacturers and Section 177 states agreed and requested the changes proposed in this rulemaking. Additionally, the alternative considered by the agency would not be more effective in carrying out the purpose for which the regulation is proposed or would be not as effective as or more burdensome to affected private persons than the proposed regulation.

2. **Description of reasonable alternatives considered that would lessen impact on small business**

No alternatives were considered to lessen the impact on small business because small businesses are not subject to the ZEV regulations and would not be impacted by these proposed amendments.

3. **Evidence relied upon to support initial determination in the notice that the regulation will not have a significant adverse economic impact on business**

The proposed amendments will not significantly affect businesses in California, since vehicle purchase price and model availability will not be adversely impacted. Numerous flexibilities exist in the ZEV regulation, and are continued in this rulemaking. It is difficult to predict how each regulated manufacturer will respond to the various flexibilities being modified in staff's proposal given continuing changes in the ZEV marketplace. However, in aggregate, staff does not expect that these changes would significantly alter the number of ZEVs a manufacturer would need to produce in any model year.

4. **Justification for adoption of regulations different from federal regulations contained in the Code of Federal Regulations**

Currently, there are no comparable federal regulations mandating auto manufacturers to produce PZEVs, AT PZEVs, TZEVs and/or ZEVs. California has authority to set its own standards to reduce emissions further to meet federal and state ambient air quality standards and climate change requirements and goals, and to require additional and separate reporting. The differing state requirements proposed are necessary to achieve additional benefits for human health, public welfare, and the environment as envisioned by authorizing legislation.

VII. SUMMARY AND RATIONALE FOR PROPOSED REGULATIONS

The need and rationale for the proposed amendments were detailed and discussed extensively in Chapter III. In this chapter, staff seeks to give clear and simple description of the proposed amendments to the ZEV regulation.

Pursuant to Government Code section 11349.1, Government Code section 11346.2(b)(1), and title 1, California Code of Regulations, section 10, staff is providing a brief summary below that identifies each section in the regulation where amendments are proposed and describes the rationale for each proposed amendment. Proposed modifications to the regulations that merely correct errors in the text or are editorial in nature are not summarized below.

§1962.1 Zero-Emission Vehicle Standards for 2009 through 2017 Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles.

Subdivision (c)(3)(A) The purpose of this subdivision is to show the equation for determining a vehicle's zero emission vehicle miles traveled (VMT) allowance. This provision specifies how the amended date of the incorporated test procedure has been updated.

Subdivision (d)(5)(B) The purpose of this subdivision is to define "fast refueling capability", which is a requirement for vehicle to earn Type III, IV, and V ZEV credit. A sentence has been added which excludes battery exchange from meeting the fast refueling definition.

Subdivision (d)(5)(E)3.a. The purpose of this subdivision is to describe the additional ZEV requirements for manufacturers on the optional Section 177 state compliance path. This subdivision has been updated to exclude transportation system credits from meeting the additional requirements in the Section 177 states, under the optional compliance path. Language has also been clarified to ensure credits will be produced and spent when meeting those additional requirements under the optional compliance path.

Subdivision (d)(5)(E)3.a.i. The purpose of this subdivision is to describe how ZEV credits may be traded and transferred within the West Region Pool and East Region Pool, respectively. This subdivision has been updated to clarify that trading and transferring of ZEV credits within the West and East region pools will commence in 2016 model year, and only 2012 through 2017 model year ZEV credits may trade and transfer within each pool. The examples have also been updated to reflect these changes.

Subdivision (d)(5)(E)3.a.ii. The purpose of this subdivision is to describe how ZEV credits may be traded and transferred between the West Region Pool and East Region Pool. This subdivision has been updated to clarify that trading and transferring

of ZEV credits between the West and East region pools will commence in 2016 model year, and only 2012 through 2017 model year ZEV credits may trade and transfer between each pool. The examples have also been updated to reflect these changes.

Subdivision (d)(5)(E)3.b.i. The purpose of this subdivision is to describe how TZEV credits may be traded and transferred within the West Region Pool and East Region Pool, respectively. This subdivision has been updated to clarify that trading and transferring of TZEV credits within the West and East region pools will commence in 2015 model year, and only 2012 through 2017 model year TZEV credits may trade and transfer within each pool. The examples have also been updated to reflect these changes. This subdivision has also been changed to improve readability.

Subdivision (d)(5)(E)3.b.ii. The purpose of this subdivision is to describe how TZEV credits may be traded and transferred between the West Region Pool and East Region Pool. This subdivision has been updated to clarify that trading and transferring of TZEV credits between the West and East region pools will commence in 2015 model year, and only 2012 through 2017 model year TZEV credits may trade and transfer between each pool. The examples have also been updated to reflect these changes. This subdivision has also been changed to improve readability.

Subdivision (d)(5)(E)3.c. The purpose of this section and table is to describe and enumerate the total percentage requirements under the optional Section 177 state compliance path. A footnote has been added to the table to specify that IVMs may meet the total percentages enumerated in the table with PZEV credits.

Subdivision (d)(5)(E)3.d. The purpose of this subdivision is to describe the reporting requirements for the optional Section 177 state compliance path. The language has been updated to ensure reporting for this subdivision will begin in model year 2015.

Subdivision (d)(5)(E)3.d. iii. The purpose of this subdivision is to require certain information pertaining to TZEVs delivered for sale to meet the optional Section 177 state compliance path. The reporting requirement for vehicle identification numbers for TZEVs placed has been removed to lessen burden on the manufacturers.

Subdivision (d)(5)(E)3.e. The purpose of this provision is to describe what happens when a manufacturer fails to meet the optional Section 177 state compliance path. The failure to comply with the optional Section 177 state path has been updated to prohibit all future transactions of credits within and between the regional pools.

Subdivision (d)(5)(F)5. The purpose of this provision is to describe the charging connection requirements for neighborhood electric vehicles. The reference to CCR section containing charging connection requirements for NEVs has been corrected.

Subdivision (h)(1) This subdivision names the test procedures used for certification to determine compliance with the ZEV regulation. The amended date of the incorporated test procedure has been updated.

List of Changes to "California Exhaust Emission Standards and Test Procedures for 2009 through 2017 Model Zero-Emission Vehicles and Hybrid Electric Vehicles in the Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicle Classes"

Section C. Zero Emission Vehicle Standards

The amendments made throughout section 1962.1 have been duplicated in this section of the test procedure.

§1962.2 Zero-Emission Vehicle Standards for 2018 and Subsequent Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles.

Subdivision (c)(3)(A) This subdivision describes how a manufacturer is to calculate its zero emission VMT allowance. The amended date of the incorporated test procedure has been updated.

Subdivision (c)(3)(A)1. This subdivision allows TZEVs with 10 miles all electric range on the US06 drive schedule to receive additional credits. The amended date of the incorporated test procedure has been updated.

Subdivision (d)(5)(E)1.a. This subdivision and table describes and enumerates the total percentage requirements under the optional Section 177 state compliance path. A footnote has been added to the table to specify that IVMs may meet the total percentages enumerated in the table with TZEV credits.

Subdivision (d)(5)(E)1.a.i. This subdivision describes how ZEV and TZEV credits may be traded and transferred within the West Region Pool and East Region Pool. This subdivision has been updated to clarify only 2012 and subsequent model year ZEV and TZEV credits may trade and transfer within each pool. The examples have also been updated to reflect these changes. Additionally, a reference has been corrected.

Subdivision (d)(5)(E)1.a.ii. The purpose of this subdivision is to describe how ZEV and TZEV credits may be traded and transferred between the West Region Pool and East Region Pool. This subdivision has been updated to clarify only 2012 and subsequent model year ZEV and TZEV credits may trade and transfer between each pool. The examples have also been updated to reflect these changes. Additionally, a reference has been corrected.

Subdivision (d)(5)(E)1.b. This subdivision describes the reporting requirements for the optional Section 177 state compliance path. The reporting requirements have been clarified to improve readability.

Subdivision (d)(5)(E)1.b.ii. This subdivision requires certain information pertaining to ZEVs and TZEVs delivered for sale to meet the optional Section 177 state compliance path. The reporting requirements have clarified to improve readability and correct a CCR reference. Additionally, the requirement to report vehicle identification numbers has been removed to lessen burden on the manufacturers.

Subdivision (d)(5)(E)1.c. This subdivision describes what happens when a manufacturer fails to meet the optional Section 177 state compliance path. The failure to comply with the optional Section 177 state path has been updated to prohibit all future transactions of credits within and between the regional pools. Additionally, language has been added to ensure the carry back provision applies to the failure to comply provision.

Subdivision (d)(5)(E)1.d. This subdivision ensures that subdivisions of section 1962.2 are still in effect. A CCR reference has been corrected.

Subdivision (d)(5)(F)5. The purpose of this provision is to describe the charging connection requirements for neighborhood electric vehicles. The reference to CCR section containing charging connection requirements for NEVs has been corrected.

Subdivision (g)(2)(A) This subdivision describes that credits from ZEVs shall be expressed in terms of credits, and that those credits may be applied toward meeting a manufacturer's ZEV requirement. A CCR reference has been corrected.

Subdivision (g)(2)(B) This subdivision describes that credits from TZEVs shall be expressed in terms of credits, and that those credits may be applied toward meeting a manufacturer's ZEV requirement. A CCR reference has been corrected.

Subdivision (g)(6)(D) This new subdivision was added to ensure no more than 50% of a manufacturer's requirements that must be met with ZEVs may be met with a combination of credits earned from transportation systems, extended range battery electric vehicles, and the ZEV-GHG over-compliance provision. Individual caps for each of these types of credits still remain in effect.

Subdivision (h)(1) This subdivision names the test procedures used for certification to determine compliance with the ZEV regulation. The amended date of the incorporated test procedure has been updated.

List of Changes to "California Exhaust Emission Standards and Test Procedures for 2018 and Subsequent Model Zero-Emission Vehicles and Hybrid Electric Vehicles in the Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicle Classes"

Section C. Zero Emission Vehicle Standards

The amendments made throughout section 1962.2 have been duplicated in this section of the test procedure.

APPENDIX A
PROPOSED REGULATION ORDER

Amendments to Sections 1962.1 and 1962.2
Title 13, California Code of Regulations

Amend title 13, California Code of Regulations, sections 1962.1, and 1962.2, to read as follows:

NOTE: Set forth below are proposed amendments to title 13 of the California Code of Regulations. Amendments to existing sections proposed and subject to comment in this rulemaking are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions. Subsections for which no changes are proposed in this rulemaking are indicated with "* * * * *".

§1962.1 Zero Emission Vehicle Standards for 2009 through 2017 Model Year Passenger Cars, Light-Duty Trucks, and Medium Vehicles.

* * * * *

(c) ***Partial ZEV Allowance Vehicles (PZEVs).***

* * * * *

(3) ***Zero-Emission VMT PZEV Allowance.***

(A) ***Calculation of Zero-Emission VMT Allowance.*** A vehicle that meets the requirements of subdivision 1962.1(c)(2) and has zero-emission vehicle miles traveled ("VMT") capability will generate an additional zero-emission VMT PZEV allowance calculated as follows:

Range	*Zero-emission VMT Allowance*
$EAER_u$ < 10 miles	0.0
$EAER_u$ ≥10 to 40 miles	$EAER_u \times (1 - UF_{Rcda})/11.028$
$EAER_u$ > 40 miles	$3.627 \times (1 - UF_n)$ Where, $n = 40 \times (R_{cda}/EAER_u)$

Date of Release: September 4, 2013; 45-day Notice Version
Date of Hearing: October 24-25, 2013

A vehicle cannot generate more than 1.39 zero-emission VMT PZEV allowances.

The urban equivalent all-electric range ($EAER_u$) and urban charge depletion range actual (R_{cda}) shall be determined in accordance with section G.11.4 and G.11.9, respectively, of the "California Exhaust Emission Standards and Test Procedures for 2009 through 2017 Model Zero-Emission Vehicles, and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck and Medium Duty Vehicle Classes," adopted December 17, 2008, and last amended ~~December 6, 2012~~[insert amended date here], incorporated by reference in section 1962.1(h). The utility factor (UF) shall be determined according to SAE International's Surface Vehicle Information Report J2841 SEP2010 (Revised September 2010), incorporated by reference herein, from the Fleet Utility Factors (FUF) Table in Appendix B or Using a polynomial curve fit with "FUF Fit" coefficients from Table 2 Utility Factor Equation Coefficients.

* * * * *

(d) ***Qualification for ZEV Multipliers and Credits.***

* * * * *

(5) ***Credits for 2009 through 2017 Model Year ZEVs.***

* * * * *

(B) ***Fast Refueling.*** The "fast refueling capability" requirement for a 2009 through 2017 model year Type III, IV, or V ZEV in subdivision 1962(d)(5)(A) will be considered met if the Type III ZEV has the capability to accumulate at least 95 miles of UDDS range in 10 minutes or less and the Type IV or V ZEV has the capability to accumulate at least 190 or 285 miles, respectively, in 15 minutes or less. For model year 2015 through 2017, qualifying for fast refueling by battery exchange is prohibited. For ZEVs that utilize more than one ZEV fuel, such as plug-in fuel cell vehicles, the Executive Officer may choose to waive these subdivision 1962.1(d)(5)(B) fast refueling requirements and base the amount of credit earned on UDDS ZEV range, as specified in subdivision 1962.1(d)(5)(A).

* * * * *

(E) ***Counting Specified ZEVs Placed in a Section 177 State and in California.***

* * * * *

3. ***Optional Section 177 State Compliance Path.*** Large volume manufacturers and intermediate volume manufacturers that choose to elect the optional Ssection 177 state compliance path must notify the Executive Officer and each Ssection 177 state in writing no later than September 1, 2014.

a. ***Additional 2016 and 2017 Model Year ZEV Requirements.*** Large volume manufacturers and intermediate volume manufacturers that elect the optional Ssection 177 state compliance path must generate additional 2012 through 2017 model year ZEV credits, including no more than 50% Type 1.5x and Type IIx vehicle credits and excluding all NEV, ~~and~~ Type 0 ZEV credits, and transportation system credits, in each Ssection 177 state ~~equal~~ to fulfill the following percentages requirements of their sales volume determined under subdivision 1962.1(b)(1)(B):

Model Years	*Additional Section 177 State ZEV Requirements*
2016	0.75%
2017	1.50%

Subdivision 1962.1(d)(5)(E)2. shall not apply to any ZEV credits used to meet a manufacturer's additional 2016 and 2017 model year ZEV requirements under this subdivision 1962.1(d)(5)(E)3.a. ZEVs produced to meet a manufacturer's additional 2016 and 2017 model year ZEV requirements under this subdivision 1962.1(d)(5)(E)3.a. must be placed in service in the Ssection 177 states no later than June 30, 2018.

i. ***Trading and Transferring ZEV Credits within the West Region Pool and East Region Pool.*** Starting in model year 2016, ~~M~~manufacturers may trade or transfer ~~specified~~2012 through 2017 model year ZEV credits, used to meet the ~~same model year~~ requirements in subdivisions 1962.1(d)(5)(E)3.a. and c., within the West Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 model year shortfall of 100 credits in State X, the manufacturer may transfer 100 (2012 through 2016 model year) ZEV credits from State Y, within the West Region pool. Starting in model year 2016, ~~M~~manufacturers may trade or transfer ~~specific~~ 2012 through 2017 model year ZEV credits, used to meet the ~~same model year~~ requirements in subdivisions 1962.1(d)(5)(E)3.a. and c., within the East Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 model year shortfall of 100 credits in State W, the manufacturer may transfer

100 (2012 through 2016 model year) ZEV credits from State Z, within the East Region pool.

ii. ***Trading and Transferring ZEV Credits between the West Region Pool and East Region Pool.*** Starting in model year 2016, ~~M~~manufacturers may trade or transfer ~~specified~~2012 through 2017 model year ZEV credits used to meet the ~~same model year~~ requirements in subdivisions 1962.1(d)(5)(E)3.a. and c. between the West Region pool and the East Region pool; however, any credits traded or transferred will incur a premium of 30% of their value. For example, in order for a manufacturer to make up a 2016 model year shortfall of 100 credits in the West Region Pool, the manufacturer may transfer 130 (2012 through 2016 model year) ZEV credits from the East Region Pool. No credits may be traded or transferred to the East Region pool or West Region pool from a manufacturer's California ZEV bank, or from the East Region pool or West Region pool to a manufacturer's California ZEV bank.

b. *Reduced TZEV Percentages.* Large volume manufacturers and intermediate volume manufacturers that elect the optional Ssection 177 state compliance path and that fully comply with the additional 2016 and 2017 model year ZEV requirements in this subdivision 1962.1(d)(5)(E)3.a. are allowed to meet TZEV percentages reduced from the allowed TZEV percentages in subdivision 1962.1(b)(2)(D)2. and 3. in 2015 through 2017 model year in each Ssection 177 state as enumerated below:

Model Year	*2015*	*2016*	*2017*
Existing TZEV Percentage	3.00%	3.00%	3.00%
Section 177 State Adjustment for Optional Compliance Path for TZEVs	75.00%	80.00%	85.00%
New Section 177 State Optional Compliance Path TZEV Percentage	2.25%	2.40%	2.55%

Manufacturers may meet the reduced TZEV percentages above with credits from ZEVs or credits from TZEVs. These reduced TZEV percentages also reduce the total ZEV percent requirement, as illustrated in subdivision 1962.1(d)(5)(E)3.c.

i. ***Trading and Transferring TZEV Credits within the West Region Pool and the East Region Pool.*** Starting in model year 2015, ~~M~~manufacturers may trade or transfer ~~specified~~2012 through 2017 model year TZEV credits, as applicable, used to meet the ~~same model year~~ subdivision 1962.1(d)(5)(E)3.c. ~~requirements~~percentages within the West Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 shortfall of 100 credits in State X, the manufacturer may transfer 100 (2012 through 2016 model year) TZEV credits from State Y, within the West Region pool. Starting in model year 2015, ~~M~~manufacturers may trade or transfer 2012 through 2017 model year TZEV credits, as applicable, used to meet the subdivision 1962.1(d)(5)(E)3.c. percentages within the East Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 model year shortfall of 100 credits in State W, the manufacturer may transfer 100 (2012 through 2016 model year) TZEV credits from State Z, within the East Region pool.

ii. ***Trading and Transferring TZEV Credits between the West Region Pool and the East Region Pool.*** Starting in model year 2015, ~~M~~manufacturers may trade or transfer ~~specified~~2012 through 2017 model year TZEV credits, as applicable, used to meet the subdivision 1962.1(d)(5)(E)3.c. ~~same model year~~ percentages ~~in subdivision 1962.1(d)(5)(E)3.c.~~ between the West Region pool and the East Region pool; however, any credits traded or transferred will incur a premium of 30% of their value. For example, in order for a manufacturer to make up a 2016 model year shortfall of 100 credits in the West Region Pool, the manufacturer may transfer 130 (2012 through 2016 model year) TZEV credits from the East Region Pool. No credits may be traded or transferred to the East Region pool or West Region pool from a manufacturer's California ZEV bank, or from the East Region pool or West Region pool to a manufacturer's California ZEV bank.

c. ***Total Requirement Percentages.*** Requirements for the minimum ZEV floor, and allowed percentages for AT PZEVs and PZEVs in subdivision 1962.1(b) remain in effect for large and intermediate volume manufacturers choosing the optional Ssection 177 state compliance path in each Ssection 177 state. However, the optional Ssection 177 compliance path requires manufacturers to meet additional ZEV requirements and allows manufacturers to meet reduced TZEV percentages as

described above in subdivision 1962.1(d)(5)(E)3.a. and b. The tables below enumerates the total annual percentage obligation in each Ssection 177 state for the 2015 through 2017 model years if the manufacturer elects the optional Ssection 177 state compliance path and produces the minimum number of credits required to meet its minimum ZEV floor and the maximum percentage allowed to be met with credits from TZEVs, AT PZEVs and PZEVs.

Large Volume Manufacturer Annual Percentage Obligations under the Section 177 State Optional Compliance Path

Years	*Total ZEV Percent Requirement for Optional Compliance Path*	*Minimum ZEV Floor for Optional Compliance Path*	*TZEVs for Optional Compliance Path*	*AT PZEVs (no change)*	*PZEVs (no change)*
2015	13.25%	3.00%	2.25%	2.00%	6.00%
2016	14.15%	3.75%	2.40%	2.00%	6.00%
2017	15.05%	4.50%	2.55%	2.00%	6.00%

Intermediate Volume Manufacturer Annual Percentage Obligations under the Section 177 State Optional Compliance Path

Years	*Total ZEV Percent Requirement for Optional Compliance Path*	*Additional ZEV Percentage*	*Percent Requirement that may be met with PZEVs*
2015	11.25%	0%	11.25%
2016	12.15%	0.75%	11.40%
2017	13.05%	1.50%	11.55%

d. *Reporting Requirements.* ~~On an annual basis~~For 2015 to 2017 model year, by May 1st of the calendar year following the close of a model year, each manufacturer that elects the optional Ssection 177 state compliance path under subdivision 1962.1(d)(5)(E)3. shall submit, in writing, to the Executive Officer and each Ssection 177 state a report, including an itemized list, that demonstrates the manufacturer has met the requirements of this subdivision 1962.1(d)(5)(E)3. in each Ssection 177 state as well as in the East Region pool and in the West Region pool. The itemized list shall include the following:

* * * * *

iii. Make, model, ~~vehicle identification number~~, credit earned, and Ssection 177 state where delivery for sale of ~~each~~ TZEVs occurred and Ssection 177 state where delivery for sale and placement in service of each ZEV occurred to meet manufacturer's requirements under subdivision 1962.1(d)(5)(E)3.c.

e. ***Right to Request Vehicle Identification Numbers.*** Upon request by the Executive Officer or a Section 177 state, each manufacturer that elects the optional Section 177 state compliance path under subdivision 1962.1(d)(5)(E)3. shall provide the vehicle identification numbers in the report required by subdivision 1962.1 (d)(5)(E)3.d.iii.

f.e. ***Failure to Meet Optional Section 177 State Compliance Path Requirements.*** A manufacturer that elects the optional Ssection 177 state compliance path and does not meet the requirements in subdivision 1962.1(d)(5)(E)3.a. by June 30, 2018 in all Ssection 177 states within an applicable pool shall be treated as subject to the total ZEV percentage requirements in section 1962.1(b) for ~~the 2015 through 2017~~all future model years in each Ssection 177 state and the pooling provisions in subdivision 1962.1(d)(5)(E)3.a. shall not apply. Any future transfers of ZEV credits between Ssection 177 states will be ~~null and void, and ZEV credits will return to the section 177 state in which the credits were earned~~prohibited. A manufacturer that elects the optional Ssection 177 state compliance path and does not meet the percentages in subdivision 1962.1(d)(5)(E)3.b. in a model year or make up their deficit within the specified time and with the specified credits allowed by subdivision 1962.1(g)(7)(A) in all Ssection 177 states within an applicable pool shall be treated as subject to the total ZEV percentage requirements in section 1962.1(b) for ~~the 2015 through 2017~~ all future model years in each Section 177 state and the pooling provisions in subdivision 1962.1(d)(5)(E)3.b. shall not apply. Any future transfers of TZEV credits between Ssection 177 states will be ~~null and void if a manufacturer fails to comply, and TZEV credits will return to the section 177 state in which the credits were earned~~prohibited. Penalties shall be calculated separately by each Ssection 177 state where a manufacturer fails to make up the ZEV deficits by the end of the 2018 model year.

gf. The provisions in section 1962.1 shall apply to a manufacturer electing the optional Ssection 177 state compliance path, except as specifically modified by this subdivision 1962.1(d)(5)(E)3.

(F) ***NEVs.*** Beginning in 2010 model year, to be eligible for the credit amount in subdivision 1962.1(d)(5)(C), NEVs must meet the following specifications and requirements in this subdivision 1962.1(d)(5)(F):

* * * * *

5. ***NEV Charging Requirements.*** Model year 2014 through 2017 NEVs must meet charging connection standard portion of the requirements specified in subdivision 1962.3(c)~~(2)~~.

* * * * *

(h) ***Test Procedures.***

(1) ***Determining Compliance***. The certification requirements and test procedures for determining compliance with this section 1962.1 are set forth in "California Exhaust Emission Standards and Test Procedures for 2009 through 2017 Model Zero-Emission Vehicles and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck and Medium-Duty Vehicle Classes," adopted December 17, 2008, and last amended ~~December 6, 2012~~[insert amended date here], which is incorporated herein by reference.

* * * * *

Note: Authority cited: Sections 39600, 39601, 43013, 43018, 43101, 43104 and 43105, Health and Safety Code. Reference: Sections 38562, 39002, 39003, 39667, 43000, 43009.5, 43013, 43018, 43018.5, 43100, 43101, 43101.5, 43102, 43104, 43105, 43106, 43204, 43205, 43205.5 and 43206, Health and Safety Code.

§1962.2. Zero-Emission Vehicle Standards for 2018 and Subsequent Model Year Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles.

* * * * *

(c) ***Transitional Zero Emission Vehicles (TZEV)***

* * * * *

(3) ***Allowances for TZEVs***

(A) ***Zero Emission Vehicle Miles Traveled TZEV Allowance Calculation***. A vehicle that meets the requirements of subdivision 1962.2(c)(2) and has zero-emission vehicle miles traveled (VMT), as defined by and calculated by the "California Exhaust Emission Standards and Test Procedures for 2018 and Subsequent Model Zero-Emission Vehicles and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck and Medium-Duty Vehicle Classes," adopted March 22, 2012, last amended ~~December 6, 2012~~[insert amended date here], which is incorporated herein by reference, and measured as equivalent all electric range (EAER) capability will generate an allowance according to the following equation:

UDDS Test Cycle Range (AER)	*Allowance*
<10 all electric miles	0.00
≥10 all electric miles	TZEV Credit = [(0.01) * EAER + 0.30]
>80 miles (credit cap)	1.10

1. ***Allowance for US06 Capability.*** TZEVs with US06 all electric range capability (AER) of at least 10 miles shall earn an additional 0.2 allowance. US06 test cycle range capability shall be determined in accordance with section G.7.5 of the "California Exhaust Emission Standards and Test Procedures for the 2018 and Subsequent Model Zero-Emission Vehicles, and Hybrid Electric Vehicles in the Passenger Car, Light-Duty Truck, and Medium Duty Vehicle Classes," adopted March 22, 2012, last amended ~~December 6, 2012~~[insert amended date here], which is incorporated herein by reference.

* * * * *

(d) ***Qualification for Credits From ZEVs.***

* * * * *

(5) ***Credits for 2018 and Subsequent Model Year ZEVs.***

* * * * *

(E) ***Counting Specified ZEVs Placed in Service in a Section 177 State and in California.*** Large volume manufacturers and intermediate volume manufacturers with credits earned from hydrogen fuel cell vehicles that are certified to the California ZEV standards applicable for the ZEV's model year, delivered for sale and placed in service in California or in a Ssection 177 state, may be counted towards compliance in California and in all Ssection 177 states with the percentage ZEV requirements in subdivision 1962.2(b). The credits earned are multiplied by the ratio of a manufacturer's applicable production volume for a model year, as specified in subdivision 1962.2(b)(1)(B), in the state receiving credit to the manufacturer's applicable production volume as specified in subdivision 1962.2(b)(1)(B), for the same model year in California (hereafter, "proportional value"). Credits generated from ZEV placement in a Ssection 177 state will be earned at the proportional value in the Ssection 177 state, and earned in California at the full value specified in subdivision 1962.2(d)(5)(A).

1. ***Optional Section 177 State Compliance Path.***

a. ***Reduced ZEV and TZEV Percentages.*** Large volume manufacturers and intermediate volume manufacturers that have fully complied with the optional Ssection 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. are allowed to meet ZEV percentage requirements and optional TZEV percentages reduced from the minimum ZEV floor percentages and TZEV percentages in subdivision 1962.2(b)(2)(E) in each Ssection 177 state equal to the following percentages of their sales volume determined under subdivision 1962.2(b)(1)(B):

ZEVs

Model Year	*2018*	*2019*	*2020*	*2021*
Existing Minimum ZEV Floor	2.00%	4.00%	6.00%	8.00%
Section 177 State Adjustment for Optional Compliance Path	62.5%	75%	87.5%	100%
Minimum Section 177 State ZEV Requirement	1.25%	3.00%	5.25%	8.00%

TZEVs

Model Year	*2018*	*2019*	*2020*	*2021*
Existing TZEV Percentage	2.50%	3.00%	3.50%	4.00%
Section 177 State Adjustment for Optional Compliance Path	90.00%	100%	100%	100%
New Section 177 State TZEV Percentage	2.25%	3.00%	3.50%	4.00%

Total Percent Requirement

Model Year	*2018*	*2019*	*2020*	*2021*
New Total Section 177 State Optional Requirements[1]	3.50%	6.00%	8.75%	12.00%

[1] Intermediate volume manufacturers may meet these new total Section 177 State optional requirements entirely with TZEV credits.

i. ***Trading and Transferring ZEV and TZEV Credits within West Region Pool and East Region Pool.*** Manufacturers that have fully complied with the optional Ssection 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. may trade or transfer ~~specified~~ 2012 and subsequent model year ZEV and TZEV credits within the West Region pool to meet the ~~same model year~~ requirements in subdivision 1962.2(d)(5)(E)~~2~~1.a, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2019 model year shortfall of 100 credits in State X, the manufacturer may transfer 100 (2012 through 2019 model year) ZEV credits from State Y, within the West Region pool. Manufacturers that have fully complied with the optional Ssection 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. may trade or transfer ~~specified~~ 2012 and subsequent model year ZEV and TZEV credits within the East Region pool to meet the ~~same model year~~ requirements in subdivision 1962.2(d)(5)(E)~~2~~1.a, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2019 model year shortfall of 100 credits in State W, the manufacturer may transfer 100 (2012 through 2019 model year) ZEV credits from State Z, within the East Region pool.

ii. ***Trading and Transferring ZEV and TZEV Credits between the West Region Pool and East Region Pool.*** Manufacturers that have fully complied with the optional Ssection 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. may trade or transfer

~~specified~~ 2012 and subsequent model year ZEV and TZEV credits to meet the ~~same model year~~ requirements in subdivision 1962.2(d)(5)(E)~~2~~1.a. between the West Region pool and the East Region pool; however, any credits traded will incur a premium of 30% of their value. For example, in order for a manufacturer to make up a 2019 model year shortfall of 100 credits in the West Region Pool, the manufacturer may transfer 130 (2012 through 2019 model year) credits from the East Region Pool. No credits may be traded or transferred to the East Region pool or West Region pool from a manufacturer's California ZEV bank, or from the East Region pool or West Region pool to a manufacturer's California ZEV bank.

b. *Reporting Requirements.* On an annual basis, by May 1st of the calendar year following the close of a model year, each manufacturer that elects the optional Ssection 177 state compliance path under subdivision 1962.1(d)(5)(E)3., shall submit, in writing, to the Executive Officer and each Ssection 177 state a report, including an itemized list, that ~~indicates where vehicles have been placed~~ demonstrates the manufacturer has met the requirements of this subdivision 1962.2(d)(5)(E)1 within the East Region pool and within the West Region pool. The itemized list shall include the following:

i. The manufacturer's total applicable volume of PCs and LDTs delivered for sale in each Ssection 177 state within the regional pool, as determined under subdivision 1962.2(b)(1)(B).

ii. Make, model, ~~vehicle identification number~~, credit earned, and Ssection 177 state where delivery for sale of ~~each~~ TZEVs and ZEVs occurred ~~and~~ to meet manufacturer's requirements under subdivision 1962.2(d)(5)(E)~~2~~1.a.

c. *Right to Request Vehicle Identification Numbers.* Upon request by the Executive Officer or a Section 177 state, each manufacturer that elects the optional Section 177 state compliance path under subdivision 1962.1(d)(5)(E)3. shall provide the vehicle identification numbers in the report required by subdivision 1962.2 (d)(5)(E)3.b.

d~~c~~. *Failure to Meet Optional Section 177 State Compliance Path Requirements.* A manufacturer that elects the optional Ssection 177 state compliance path under subdivision 1962.1(d)(5)(E)3, and does not meet the modified percentages in subdivision 1962.2(d)(5)(E)~~2~~1.a. in a model year or make up their deficit within the specified time and with the specified credits allowed by subdivision 1962.2(g)(7)(A) in all

Ssection 177 states of the applicable pool, shall be treated as subject to the total ZEV percentage requirements in section 1962.2(b) for ~~the 2018 through 2021~~all future model years in each Ssection 177 state, and the pooling provisions in subdivision 1962.2(d)(5)(E)~~2~~1.a. shall not apply. Any future transfers of ZEV or TZEV credits between Ssection 177 states will be ~~null and void if a manufacturer fails to comply, and ZEV or TZEV credits will return to the section 177 state in which the credits were earned~~prohibited. Penalties shall be calculated separately by each Ssection 177 state where a manufacturer fails to make up the ZEV deficits within the specified time and with the credits allowed by subdivision 1962.2(g)(7)(A)~~by the end of the 2018 model year~~.

~~e~~**d.** The provisions of section 1962.2 shall apply to a manufacturer electing the optional section 177 state compliance path, except as specifically modified by this subdivision 1962.2(d)(5)(E)~~2~~1.

(F) ***NEVs.*** NEVs must meet the following to be eligible for 0.15 credits:

* * * * *

4. ***NEV Charging Requirements.*** A NEV must meet charging requirements specific in subdivision 1962.3(c)~~(2)~~.

* * * * *

(g) ***Generation and Use of Credits; Calculation of Penalties***

* * * * *

(2) ***ZEV Credit Calculations.***

(A) ***Credits from ZEVs.*** The amount of credits earned by a manufacturer in a given model year from ZEVs shall be expressed in units of credits, and shall be equal to the number of credits from ZEVs produced and delivered for sale in California that the manufacturer applies towards meeting the ZEV requirements, or, if applicable, requirements specified under subdivision 1962.2(d)(5)(E)~~2~~1.a. for the model year subtracted from the number of ZEVs produced and delivered for sale in California by the manufacturer in the model year.

(B) ***Credits from TZEVs.*** The amount of credits earned by a manufacturer in a given model year from TZEVs shall be expressed in units of credits, and shall be equal to the total number of TZEVs produced and delivered for sale in California that the manufacturer applies towards meeting its ZEV requirement, or, if applicable, requirements specified under subdivision 1962.2(d)(5)(E)~~2~~1.a. for the model

year subtracted from the total number of ZEV allowances from TZEVs produced and delivered for sale in California by the manufacturer in the model year.

* * * * *

(4) *ZEV Credits for Advanced Technology Demonstration Programs.*

(A) *[Reserved]*

(B) *ZEVs.* ZEVs, including BEVxs, excluding NEVs, placed in a small or intermediate volume manufacturer's California advanced technology demonstration program for a period of two or more years, may earn ZEV credits even if the vehicle is not "delivered for sale" or registered with the California DMV. To earn such credits, the manufacturer must demonstrate to the reasonable satisfaction of the Executive Officer that the vehicles will be regularly used in applications appropriate to evaluate issues related to safety, infrastructure, fuel specifications or public education, and that for 50 percent or more of the first two years of placement the vehicle will be operated in California. Such a vehicle is eligible to receive the same credit that it would have earned if delivered for sale, and for fuel cell vehicles, placed in service. To determine vehicle credit, the model year designation for a demonstration vehicle shall be consistent with the model year designation for conventional vehicles placed in the same timeframe. Manufacturers may earn credit for up to 25 vehicles per model, per Ssection 177 state, per year under this subdivision 1962.2(g)(4). A manufacturer's vehicles in excess of the 25-vehicle cap will not be eligible for advanced technology demonstration program credits.

(5) *ZEV Credits for Transportation Systems.*

* * * * *

(C) *Cap on Use of Transportation System Credits.*

1. *ZEVs.* Transportation system credits earned or allocated by ZEVs or BEVxs pursuant to subdivision 1962.1 (g)(5), not including any credits earned by the vehicle itself, may be used to satisfy up to one-tenth of a manufacturer's ZEV obligation in any given model year, and may be used to satisfy up to one-tenth of a manufacturer's ZEV obligation which must be met with ZEVs, as specified in subdivision 1962.2(b)(2)(E) or, if applicable, requirements specified under subdivision 1962.2(d)(5)(E)2.a..

* * * * *

(6) *Use of ZEV Credits.* A manufacturer may meet the ZEV requirements in a given model year by submitting to the Executive Officer a commensurate amount of ZEV credits, consistent with subdivision 1962.2(b). Credits in each of the categories

may be used to meet the requirement for that category as well as the requirements for lesser credit earning ZEV categories, but shall not be used to meet the requirement for a greater credit earning ZEV category, except for discounted PZEV and AT PZEV credits. For example, credits produced from TZEVs may be used to comply with the portion of the requirement that may be met with credits from TZEV, but not with the portion that must be satisfied with credits from ZEVs. These credits may be earned previously by the manufacturer or acquired from another party.

(A) ***Use of Discounted PZEV and AT PZEV Credits and NEV Credits.*** For model years 2018 through 2025, discounted PZEV and AT PZEV credits, and NEV credits may be used to satisfy up to one-quarter of the portion of a manufacturer's requirement that can be met with credits from TZEVs, or, if applicable, the portion of a manufacturer's obligation that may be met with TZEVs specified under subdivision 1962.2(d)(5)(E)2.a.~~.~~ Intermediate volume manufacturers may fulfill their entire requirement with discounted PZEV and AT PZEV credits, and NEV credits in model years 2018 and 2019. These credits may be earned previously by the manufacturer or acquired from another party. Discounted PZEV and AT PZEV credits may no longer be used after model year 2025 compliance.

* * * * *

(D) ***Cap on Use of Specified Credits.***

For 2018 and subsequent model year, manufacturers may only meet up to 50% of the portion of their requirement that must be met with credits from ZEVs from a combination of credits earned under subsections 1962.1(d)(5)(G), 1962.2 (d)(5)(G), 1962.1(g)(5), or 1962.2(g)(6)(C). Individual caps for credits earned subsections 1962.1(d)(5)(G), 1962.2 (d)(5)(G), 1962.1(g)(5), or 1962.2(g)(6)(C) remain in effect in any given model year.

* * * * *

(h) ***Test Procedures.***

(1) ***Determining Compliance.*** The certification requirements and test procedures for determining compliance with this section 1962.2 are set forth in "California Exhaust Emission Standards and Test Procedures for 2018 and Subsequent Model Zero-Emission Vehicles and Hybrid Electric Vehicles, in the Passenger Car, Light-Duty Truck and Medium-Duty Vehicle Classes," adopted March 22, 2012, last amended ~~December 6, 2012~~[insert amended date here], which is incorporated herein by reference.

Note: Authority cited: Sections 39600, 39601, 43013, 43018, 43101, 43104 and 43105, Health and Safety Code. Reference: Sections 38562, 39002, 39003, 39667, 43000, 43009.5, 43013, 43018, 43018.5, 43100, 43101, 43101.5, 43102, 43104, 43105, 43106, 43107, 43204, and 43205.5, Health and Safety Code.

APPENDIX B
PROPOSED

California Environmental Protection Agency
AIR RESOURCES BOARD

CALIFORNIA EXHAUST EMISSION STANDARDS AND TEST PROCEDURES FOR 2009 THROUGH 2017 MODEL ZERO-EMISSION VEHICLES AND HYBRID ELECTRIC VEHICLES, IN THE PASSENGER CAR, LIGHT-DUTY TRUCK AND MEDIUM-DUTY VEHICLE CLASSES

Adopted: December 17, 2008
Amended: December 2, 2009
Amended: March 22, 2012
Amended: December 6, 2012
Amended: [insert adoption date]

Note: The proposed amendments to this document are shown in underline to indicate additions and strikeout to indicate deletions compared to the test procedures as adopted December 6, 2012. Existing intervening text that is not amended in this rulemaking is indicated by "* * * * *".

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C. Zero-Emission Vehicle Standards.

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4. Qualification for ZEV Multipliers and Credits.

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4.4 Credits for 2009 through 2017 Model Years ZEVs.

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(b) *Fast Refueling.* The "fast refueling capability" requirement for a 2009 through 2017 model year Type III, IV, or V ZEV in subdivision C.4.4.(a) will be considered met if the Type III ZEV has the capability to accumulate at least 95 miles of UDDS range in 10 minutes or less and the Type IV or V ZEV has the capability to accumulate at least 190 or 285 miles, respectively, in 15 minutes or less. For model year 2015 through 2017, qualifying for fast refueling by battery exchange is prohibited. For ZEVs that utilize more than one ZEV fuel, such as plug-in fuel cell vehicles, the Executive Officer may choose to waive these subdivision C.4.4.(b) fast fueling requirements and base the amount of credit earned on UDDS ZEV range, as specified in subdivision C.4.4.(a).

(c) *ZEV Credits for 2009 through 2017 Model-Year ZEVs.* A 2009 through 2017 model-year ZEV, other than a NEV or Type 0, earns 1 ZEV credit when it is produced and delivered for sale in California. A 2009 through 2017 model-year ZEV earns additional credits based on the earliest year in which the ZEV is placed in service (not earlier than the ZEV's model year). The vehicle must be delivered for sale and placed in service in a Section 177 state or in California in order to earn the total credit amount. The total credit amount will be earned in the state (i.e. California or a Section 177 state) in which the vehicle was delivered for sale. The following table identifies the total credits that a ZEV in each of the eight ZEV tiers will earn, including the credit not contingent on placement in service, if it is placed in service in the specified calendar year or by June 30 after the end of the specified calendar year. A vehicle is not eligible to receive credits if it is placed in service after December 31, five calendar years after the model year. For example, if a vehicle is produced in 2012, but does not get placed until January 1, 2018, the vehicle would no longer be eligible for ZEV credits.

* * * * *

(e) *Counting Specified ZEVs Placed in a Section 177 State and in California.*

* * * * *

(3) *Optional Section 177 State Compliance Path.* Large volume

manufacturers and intermediate volume manufacturers that choose to elect the optional section 177 state compliance path must notify the Executive Officer and each section 177 state in writing no later than September 1, 2014.

(A) *Additional 2016 and 2017 Model Year ZEV Requirements.* Large volume manufacturers and intermediate volume manufacturers that elect the optional section 177 state compliance path must generate additional 2012 through 2017 model year ZEV credits, including no more than 50% Type 1.5x and Type IIx vehicle credits and excluding all NEV, ~~and~~ Type 0 ZEV credits, and transportation system credits, in each section 177 state ~~equal~~ to fulfill the following percentages requirements of their sales volume determined under subdivision C.4.5(e)(3)(A)1.:

Model Years	Additional Section 177 State ZEV Requirements
2016	0.75%
2017	1.50%

Subdivision C.4.5(e)(2) shall not apply to any ZEV credits used to meet a manufacturer's additional 2016 and 2017 model year ZEV requirements under this subdivision C.4.5(e)(3)(A). ZEVs produced to meet a manufacturer's additional 2016 and 2017 model year ZEV requirements under this subdivision C.4.5(e)(3)(A) must be placed in service in the Ssection 177 states no later than June 30, 2018.

1. *Trading and Transferring ZEV Credits within the West Region Pool and East Region Pool.* Starting in model year 2016, ~~M~~manufacturers may trade or transfer ~~specified~~2012 through 2017 model year ZEV credits, used to meet the ~~same model year~~ requirements in subdivision C.4.5(e)(3)(A) and (C), within the West Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 model year shortfall of 100 credits in State X, the manufacturer may transfer 100 (2012 and 2016 model year) ZEV credits, from State Y, within the West Region pool. Starting in model year 2016, ~~M~~manufacturers may trade or transfer ~~specific~~ 2012 through 2017 model year ZEV credits, used to meet the ~~same model year~~ requirements in subdivision C.4.5(e)(3)(C), within the East Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 model year shortfall of 100 credits in State W, the manufacturer may transfer 100 (2012 through 2016 model year) ZEV credits from State Z, within the East Region pool.

2. *Trading and Transferring ZEV Credits between the West Region Pool and East Region Pool.* Starting in model year 2016, ~~M~~manufacturers may trade or transfer ~~specified~~2012 through 2017 model year ZEV credits used to meet the ~~same model year~~ requirements in subdivision C.4.5(e)(3)(A) and (C) between the

West Region pool and the East Region pool; however, any credits traded or transferred will incur a premium of 30% of their value. For example, in order for a manufacturer to make up a 2016 model year shortfall of 100 credits in the West Region Pool, the manufacturer may transfer 130 (2012 through 2016 model year) ZEV credits from the East Region Pool. No credits may be traded or transferred to the East Region pool or West Region pool from a manufacturer's California ZEV bank, or from the East Region pool or West Region pool to a manufacturer's California ZEV bank.

(B) *Reduced TZEV Percentages.* Large volume manufacturers and intermediate volume manufacturers that elect the optional Ssection 177 state compliance path and that fully comply with the additional 2016 and 2017 model year ZEV requirements in this subdivision C.4.5(e)(3)(A). are allowed to meet TZEV percentages reduced from the allowed TZEV percentages in subdivision C.2.2(d)(2) and (3) in 2015 through 2017 model year in each Ssection 177 state as enumerated below:

Model Year	2015	2016	2017
Existing TZEV Percentage	3.00%	3.00%	3.00%
Section 177 State Adjustment for Optional Compliance Path for TZEVs	75.00%	80.00%	85.00%
New Section 177 State Optional Compliance Path TZEV Percentage	2.25%	2.40%	2.55%

Manufacturers may meet the reduced TZEV percentages above with credits from ZEVs or credits from TZEVs. These reduced TZEV percentages also reduce the total ZEV percent requirement, as illustrated in subdivision C.4.5(e)(3)(C).

1. *Trading and Transferring TZEV Credits within the West Region Pool and East Region Pool.* Starting in model year 2015, Mmanufacturers may trade or transfer specified2012 through 2017 model year TZEV credits, as applicable, used to meet the same model year subdivision C.4.5(e)(3)(C) percentages within the West Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 shortfall of 100 credits in State X, the manufacturer may transfer 100 (2012 through 2016 model year) TZEV credits from State Y, within the West Region pool. Starting in model year 2015, mManufacturers may trade or transfer TZEV credits, as applicable, used to meet the same model year subdivision C.4.5(e)(3)(C) percentages within the East Region pool, and will incur no premium on their credit values. For example, for a manufacturer to make up a 2016 model year shortfall of 100 credits in State W, the manufacturer may transfer 100 (2012 through 2016 model year) TZEV credits from State Z, within the East Region pool.

2. *Trading and Transferring TZEV Credit between the West Region Pool and East Region Pool.* Starting in model year 2015, mManufacturers may trade or transfer ~~specified~~ 2012 through 2017 model year TZEV credits, as applicable, used to meet subdivision C.4.5(e)(3)(C) ~~the same model year~~ percentages ~~in subdivision C.4.5(e)(3)(C)~~ between the West Region pool and the East Region pool; however, any credits transferred will incur a premium of 30% of their value. For example, in order for a manufacturer to make up a 2016 model year shortfall of 100 credits in the West Region Pool, the manufacturer may transfer 130 (2012 through 2016 model year) TZEV credits from the East Region Pool. No credits may be traded or transferred to the East Region pool or West Region pool from a manufacturer's California ZEV bank, or from the East Region pool or West Region pool to a manufacturer's California ZEV bank.

(C) *Total Requirement Percentages.* Requirements for the minimum ZEV floor, and allowed percentages for AT PZEVs and PZEVs in subdivision C.2 remain in effect for large and intermediate volume manufacturers choosing the optional Ssection 177 state compliance path in each Ssection 177 state. However, the optional Section 177 compliance path requires manufacturers to meet additional ZEV requirements and allows manufacturers to meet reduced TZEV percentages as described above in subdivision C.4.5(e)(3)(A) and (B). The table below enumerates the total annual percentage obligation in each Ssection 177 state for the 2015 through 2017 model years if the manufacturer elects the optional Ssection 177 state compliance path and produces the minimum number of credits required to meet its minimum ZEV floor and the maximum percentage allowed to be met with credits from TZEVs, AT PZEVs and PZEVs.

Large Volume Manufacturer Annual Percentage Obligations under the Section 177 State Optional Compliance Path

Years	Total ZEV Percent Requirement for Optional Compliance Path	Minimum ZEV Floor for Optional Compliance Path	TZEVs for Optional Compliance Path	AT PZEVs (no change)	PZEVs (no change)
2015	13.25%	3.00%	2.25%	2.00%	6.00%
2016	14.15%	3.75%	2.40%	2.00%	6.00%
2017	15.05%	4.50%	2.55%	2.00%	6.00%

Intermediate Volume Manufacturer Annual Percentage Obligations under the Section 177 State Optional Compliance Path

Years	Total ZEV Percent Requirement	Additional ZEV Percentage	Percent Requirement that may be

	for Optional Compliance Path		met with PZEVs
2015	11.25%	0%	11.25%
2016	12.15%	0.75%	11.40%
2017	13.05%	1.50%	11.55%

~~d.~~(D) *Reporting Requirements.* ~~On an annual basis~~For 2015 to 2017 model year, by May 1st of the calendar year following the close of a model year, each manufacturer that elects the optional Ssection 177 state compliance path shall submit, in writing, to the Executive Officer and each Ssection 177 state a report, including an itemized list, that demonstrates the manufacturer has met the requirements of this subdivision C.4.5(e)(3)(C) in each Ssection 177 state as well as in the East Region pool and in the West Region pool. The itemized list shall include the following:

* * * * *

iii. Make, model, ~~vehicle identification number,~~ credit earned, and Ssection 177 state where delivery for sale of ~~each~~ TZEVs occurred and Ssection 177 state where delivery for sale and placement in service of each ZEV occurred to meet manufacturer's requirements under subdivision C.4.5(e)(3)(C)

(E) *Right to Request Vehicle Identification Numbers.* Upon request by the Executive Officer or a Section 177 state, each manufacturer that elects the optional section 177 state compliance path under subdivision C.4.5(e)(3) shall provide the vehicle identification numbers in the report required by subdivision C.4.5(e)(3)(D)iii.

~~e.~~(F) *Failure to Meet Optional Section 177 State Compliance Path Requirements.* A manufacturer that elects the optional Ssection 177 state compliance path and does not meet the requirements in subdivision C.4.5(e)(3)(A) by June 30, 2018 in all Ssection 177 states within an applicable pool shall be treated as subject to the total ZEV percentage requirements in section C.2 for ~~the 2015 through 2017~~future model years in each Ssection 177 state and the pooling provisions in subdivision C.4.5(e)(3)(A) shall not apply. Any transfers of ZEV credits between Ssection 177 states will be ~~null and void, and ZEV credits will return to the section 177 state in which the credits were earned~~prohibited. A manufacturer that elects the optional Ssection 177 state compliance path and does not meet the percentages in subdivision C.4.5(e)(3)(B) in a model year or make up their deficit within the specified time and with the specified credits allowed by subdivision C.7.7(a) in all Ssection 177 states within an applicable pool shall be treated as subject to the ZEV percentage requirements in section C.2 for the ~~2015 through 2017~~all future model years in each Section 177 state and the pooling provisions in subdivision C.4.5(e)(3)(B) shall not apply. Any future transfers of TZEV credits between section 177 states will be ~~null and void if a manufacturer fails to comply, and TZEV credits will return to the section 177 state in which the credits were earned~~prohibited. Penalties shall be calculated separately by each section 177 state where a manufacturer fails to make up the ZEV deficits by the end of the 2018 model

year.

* * * * *

f.(G) The provisions in section C shall apply to a manufacturer electing the optional Ssection 177 state compliance path, except as specifically modified by this subdivision C.4.5(e)(3).

* * * * *

APPENDIX C
PROPOSED

California Environmental Protection Agency
AIR RESOURCES BOARD

CALIFORNIA EXHAUST EMISSION STANDARDS AND TEST PROCEDURES FOR 2018 AND SUBSEQUENT MODEL ZERO-EMISSION VEHICLES AND HYBRID ELECTRIC VEHICLES, IN THE PASSENGER CAR, LIGHT-DUTY TRUCK AND MEDIUM-DUTY VEHICLE CLASSES

Adopted: March 22, 2012
Amended: December 6, 2012
Amended: [insert amended date]

Note: The proposed amendments to this document are shown in underline to indicate additions and strikeout to indicate deletions compared to the test procedures as adopted December 6, 2012. Existing intervening text that is not amended in this rulemaking is indicated by "* * * * *".

* * * * *

C. Zero-Emission Vehicle Standards.

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4. Qualification for Credits From ZEVs.

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4.5 Credits for 2018 and Subsequent Model Years.

* * * * *

(~~1~~e) *Provisions for 2018 through 2025 Model Years.* Large volume manufacturers and intermediate volume manufacturers with credits earned from hydrogen fuel cell vehicles that are certified to the California ZEV standards applicable for the ZEV's model year, delivered for sale and placed in service in California or in a section 177 state, may be counted towards compliance in California and in all section 177 states with the percentage ZEV requirements in subdivision C.2. The credits earned are multiplied by the ratio of a manufacturer's applicable production volume for a model year, as specified in subdivision C.2.1(b), in the state receiving credit to the manufacturer's applicable production volume as specified in subdivision C.2.1(b), for the same model year in California(hereafter, "proportional value"). Credits generated from ZEV placement in a Ssection 177 state will be earned at the proportional value in the Ssection 177 state, and earned in California at the full value specified in subdivision C.4.5(a).

(~~2~~1) *Optional Section 177 State Compliance Path.*

(A) *Reduced ZEV and TZEV Percentages.* Large volume manufacturers and intermediate volume manufacturers that have fully complied with the optional section 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. are allowed to meet ZEV percentage requirements and optional TZEV percentages reduced from the minimum ZEV floor percentages and TZEV percentages in subdivision C.2.2(e) in each Ssection 177 state equal to the following percentages of their sales volume determined under subdivision 1962.2(b)(1)(B):

ZEVs

Model Year	2018	2019	2020	2021
Existing Minimum ZEV Floor	2.00%	4.00%	6.00%	8.00%
Section 177 State Adjustment for Optional Compliance Path	62.5%	75%	87.5%	100%
Minimum Section 177 State ZEV Requirement	1.25%	3.00%	5.25%	8.00%

TZEVs

Model Year	2018	2019	2020	2021
Existing TZEV Percentage	2.50%	3.00%	3.50%	4.00%
Section 177 State Adjustment for Optional Compliance Path	90.00%	100%	100%	100%
New Section 177 State TZEV Percentage	2.25%	3.00%	3.50%	4.00%

Total Percent Requirement

Model Year	2018	2019	2020	2021
New Total Section 177 State Optional Requirements[1]	3.50%	6.00%	8.75%	12.00%

[1] Intermediate volume manufacturers may meet these new total Section 177 State optional requirements entirely with TZEV credits.

1. *Trading and Transferring ZEV and TZEV Credits within West Region Pool and East Region Pool.* Manufacturers that have fully complied with the optional Ssection 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. may trade or transfer ~~specified~~ 2012 and subsequent model year ZEV and TZEV credits within the West Region pool to meet the ~~same model year~~ requirements in subdivision C.4.5(e)(~~2~~1)(A) and will incur no premium on their credit values. For example, for a manufacturer to make up a 2019 model year shortfall of 100 credits in State X, the manufacturer may transfer 100 (2012 through 2019 model year) ZEV credits from State Y, within the West Region pool. Manufacturers that have fully complied with the optional section 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. may trade or transfer ~~specified~~ 2012 and subsequent model year ZEV and TZEV credits within the East Region pool to meet the same model year requirements in subdivision C.4.5(e)(~~2~~1)(A), and will incur no premium on their credit values. For example, for a manufacturer to make up a 2019 model year shortfall of 100 credits in State W, the manufacturer may transfer 100 (2012 through 2019 model year) ZEV credits from State Z, within the East Region pool.

2. *Trading and Transferring ZEV and TZEV Credits between the West Region Pool and the East Region Pool.* Manufacturers that have fully complied with the optional Ssection 177 state compliance path requirements in subdivision 1962.1(d)(5)(E)3. may trade or transfer ~~specified~~ 2012 and subsequent model year ZEV and TZEV credits to meet the same model year requirements in subdivision C.4.5(e)(~~2~~1)(A)~~.a.~~ between the West Region pool and the East Region pool; however, any credits traded will incur a premium of 30% of their value. For example, in order for a

manufacturer to make up a 2019 model year shortfall of 100 credits in the West Region Pool, the manufacturer may transfer 130 (2012 through 2019 model year) credits from the East Region Pool. No credits may be traded or transferred to the East Region pool or West Region pool from a manufacturer's California ZEV bank, or from the East Region pool or West Region pool to a manufacturer's California ZEV bank.

(B) *Reporting Requirements.* On an annual basis, by May 1st of the calendar year following the close of a model year, each manufacturer that elects the optional section 177 state compliance path under subdivision 1962.1(d)(5)(E)3 shall submit, in writing, to the Executive Officer and each Ssection 177 state a report, including an itemized list, that ~~indicates where vehicles have been placed~~ demonstrates the manufacturer has met the requirements of this subdivision C.4.5(e)(1)(A) within the East Region pool and within the West Region pool. The itemized list shall include the following:

1. The manufacturer's total applicable volume of PCs and LDTs delivered for sale in each Ssection 177 state within the regional pool, as determined under subdivision C.2.1(b).

2. Make, model, ~~vehicle identification number~~, credit earned, and Ssection 177 state where delivery for sale of ~~each~~ TZEVs and ZEV occurred and to meet manufacturer's requirements under subdivision C.4.5(e)(~~2~~1)(A).

(C) *Right to Request Vehicle Identification Numbers.* Upon request by the Executive officer, or a Section 177 state, each manufacturer that elects the optional Section 177 state compliance path under subdivision 1962.1(d)(5)(E)3. Shall provide the vehicle identifications numbers in the report required by subdivision C.4.5(e)(3)(B).

(~~C~~D) *Failure to Meet Optional Section 177 State Compliance Path Requirements.* A manufacturer that elects the optional Ssection 177 state compliance path subdivision 1962.1(d)(5)(E)3 and does not meet the modified percentages in subdivision C.4.5(e)(~~2~~1)(A) in a model year or make up their deficit within the specified time and with the specified credits allowed by subdivision C.7.7(a) in all Ssection 177 states of the applicable pool, shall be treated as subject to the ZEV percentage requirements in section C.2 for all future model years in each Ssection 177 state, and ~~T~~the pooling provisions in subdivision C.4.5(e)(~~2~~1)(A) shall not apply. Any future transfers of ZEV or TZEV credits between Ssection 177 states will be ~~null and void if a manufacturer fails to comply, and ZEV or TZEV credits will return to the section 177 state in which the credits were earned~~prohibited. Penalties shall be calculated separately by each Ssection 177 state where a manufacturer fails to make up the ZEV deficits within the specified time and with the credits allowed by subdivision C.7.7(a) ~~by the end of the 2018 model year~~.

(~~D~~E) The provisions of section C shall apply to a manufacturer electing

the optional Ssection 177 state compliance path, except as specifically modified by this subdivision C.4.5(e)(2).

(f) *NEVs.* NEVs must meet the following to be eligible for 0.15 credits:

* * * * *

(5) *NEV Charging Requirements.* A NEV must meet charging connection standard portion of the requirements specified in subdivision 1962.3(c)~~(2)~~.

* * * * *

7. Generation and Use of ZEV Credits; Calculation of Penalties

* * * * *

7.2 ZEV Credit Calculations.

(a) *Credits from ZEVs.* The amount of credits earned by a manufacturer in a given model year from ZEVs shall be expressed in units of credits, and shall be equal to the number of credits from ZEVs produced and delivered for sale in California that the manufacturer applies towards meeting the ZEV requirements, or, if applicable, requirements specified under subdivision C.4.5(e)(~~2~~1)(A) for the model year subtracted from the number of ZEVs produced and delivered for sale in California by the manufacturer in the model year.

(b) *Credits from TZEVs.* The amount of credits earned by a manufacturer in a given model year from TZEVs shall be expressed in units of credits, and shall be equal to the total number of TZEVs produced and delivered for sale in California that the manufacturer applies towards meeting its ZEV requirement, or, if applicable, requirements specified under subdivision C.4.5(e)(~~2~~1)(A) for the model year subtracted from the total number of ZEV allowances from TZEVs produced and delivered for sale in California by the manufacturer in the model year.

* * * * *

7.4 ZEV Credits for Advanced Technology Demonstration Programs.

(a) *[Reserved]*

(b) *ZEVs.* ZEVs, including BEVxs, excluding NEVs, placed in a small or intermediate volume manufacturer's California advanced technology demonstration program for a period of two or more years, may earn ZEV credits even if the vehicle is not "delivered for sale" or registered with the California DMV. To earn such credits, the manufacturer must demonstrate to the reasonable satisfaction of the Executive Officer that the vehicles will be regularly used in applications appropriate to evaluate issues

related to safety, infrastructure, fuel specifications or public education, and that for 50 percent or more of the first two years of placement the vehicle will be operated in California. Such a vehicle is eligible to receive the same credit that it would have earned if delivered for sale, and for fuel cell vehicles, placed in service. To determine vehicle credit, the model year designation for a demonstration vehicle shall be consistent with the model year designation for conventional vehicles placed in the same timeframe. Manufacturers may earn credit for up to 25 vehicles per model, per Ssection 177 state, per year under this subdivision C.7.4. A manufacturer's vehicles in excess of the 25-vehicle cap will not be eligible for advanced technology demonstration program credits.

* * * * *

7.6 Use of ZEV Credits. A manufacturer may meet the ZEV requirements in a given model year by submitting to the Executive Officer a commensurate amount of ZEV credits, consistent with subdivision C.2. Credits in each of the categories may be used to meet the requirement for that category as well as the requirements for lesser credit earning ZEV categories, but shall not be used to meet the requirement for a greater credit earning ZEV category, except for discounted PZEV and AT PZEV credits. For example, credits produced from TZEVs may be used to comply with the portion of the requirement that may be met with credits from TZEV, but not with the portion that must be satisfied with credits from ZEVs. These credits may be earned previously by the manufacturer or acquired from another party.

(c) *GHG-ZEV Over Compliance Credits.*

* * * * *

(3) *Use of GHG-ZEV Over Compliance Credits.* A manufacturer may use no more than the percentage enumerated in the table below to meet either the total ZEV requirement nor the portion of their ZEV requirement that must be met with ZEV credits, with credits earned under this subdivision C.7.6(c).

2018	2019	2020	2021
50%	50%	40%	30%

Credits earned in any given model year under this subdivision C.7.6(c) may only be used in the applicable model year and may not be used in any other model year.

Credits calculated under this provision must also be removed from the GHG compliance bank, and cannot be banked for future compliance toward section 1961.3, or towards compliance with the National greenhouse gas program requirements as allowed by subdivision 1961.3(c).

* * * * *

(d) *Cap on Use of Specified Credits.*

For 2018 and subsequent model year, manufacturers may only meet up to 50% of the portion of their requirement that must be met with credits from ZEVs from a combination of credits earned under subsections 1962.1(d)(5)(G), 1962.1(g)(5), or subdivisions

C.4.5(g), C.7.6(c). Individual caps for credits earned subsections 1962.1(d)(5)(G), 1962.1(g)(5), or subdivisions C.4.5(g), C.7.6(c) remain in effect in any given model year.

TITLE 13. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER A PROPOSED REGULATION FOR *STATE IMPLEMENTATION PLAN CREDIT FROM MOBILE AGRICULTURAL EQUIPMENT*

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider a proposed adoption of a regulation for *State Implementation Plan Credit from Mobile Agricultural Equipment.*

DATE: October 24, 2013

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., Thursday, October 24, 2013, and may continue at 8:30 a.m., on Friday, October 25, 2013. This item may not be considered until October 25, 2013. Please consult the agenda for the hearing, which will be available at least 10 days before October 24, 2013, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of California Code of Regulations, title 13, section 2428.

Documents Incorporated by Reference: "*2011 Carl Moyer Program Guidelines*" (approved April 28, 2011); "*2008 Carl Moyer Program Guidelines*" (approved March 27, 2008); and "*2005 Carl Moyer Program Guidelines*" (approved November 17, 2005)

Background and Effect of the Proposed Rulemaking:

In 2007, the San Joaquin Valley Air Pollution Control District (SJVAPCD) developed a State Implementation Plan (SIP) to meet the 0.08 parts per million (ppm) 8-hour ozone standard by 2023. The 2007 SIP, which was approved by the United States Environmental Protection Agency (U.S. EPA) in December 2011, contains a measure by ARB to propose a regulation for mobile agricultural equipment in the San Joaquin Valley, which is comprised of the counties within the SJVAPCD, including San Joaquin, Stanislaus, Merced, Madera, Fresno, Tulare, Kings Counties, as well as the western portion of Kern County. Specifically, the approved 2007 SIP includes a goal to achieve

emissions reductions of 5 to 10 tons per day of oxides of nitrogen (NOx) in the San Joaquin Valley by 2017 in order to accelerate air quality progress.

ARB incentive-based air quality programs are designed to achieve near- and long-term emission reductions through investments in cleaner technologies. These programs include the Carl Moyer Program, Assembly Bill 118 Air Quality Improvement Program (AQIP), and Proposition 1B (Goods Movement and Lower-Emission School Bus Programs). Each of these programs addresses specific air quality priorities, such as the early replacement of older vehicles and engines with newer, cleaner engines and the development and deployment of advanced technology vehicles and equipment. The success of these programs helps California accelerate progress toward achieving health-based air quality standards, prevents federal sanctions such as the loss of federal highway funds, and assists businesses with equipment upgrades prior to regulatory requirements (with cost-sharing to leverage private funding for all projects).

In particular, since 1998 ARB's Carl Moyer Program has funded the extra capital cost of cleaner-than-required vehicles and equipment to help achieve air pollution reductions that are both early and surplus to regulations. Funds for the Carl Moyer Program include tire replacement and vehicle registration (smog abatement) fees. The Carl Moyer Program provides incentives to private and public agencies to voluntarily clean up older, dirtier vehicles and mobile off-road engines through retrofit or replacement. ARB develops statewide implementation guidelines, distributes funds to air districts, and conducts periodic oversight. Air districts choose which project types to fund from a variety of eligible categories, including on-road and off-road vehicles and equipment, marine, shore power, locomotives, stationary agriculture pumps, emergency equipment, lawn and garden equipment, and light duty vehicle scrap. Funded projects must achieve early or extra emission reductions not otherwise required by law or regulation. SJVAPCD (like other large and medium-sized air districts) contributes match funds as required by the Carl Moyer Program.

SJVAPCD has partnered with ARB from the beginning of the Carl Moyer Program, and has used the Carl Moyer Program as a model for other local funded programs. As demonstrated through multiple reviews and audits, SJVAPCD's incentive programs are highly efficient and effective. SJVAPCD's voluntary incentive programs fund cleaner-than-required engines and equipment and are a crucial component of the SJVAPCD's efforts to reduce emissions and meet air quality standards. Since the adoption of the 2007 SIP, the agricultural industry has worked collaboratively with the SJVAPCD and the U.S. Department of Agriculture Natural Resource Conservation Service (NRCS) to procure and expend federal, state and local funds to reduce pollution by accelerating the turnover of older, dirtier mobile agricultural equipment with the cleanest available technologies, which for mobile agricultural equipment is primarily comprised of Tier 3 and cleaner off-road engines. U.S. EPA has provided guidance on incorporating voluntary measures, such as these incentive programs, into SIPs. To meet U.S. EPA criteria for SIP creditability of incentive funded projects, the emission reductions must be surplus, quantifiable, enforceable, and permanent.

In 2010, SJVAPCD, ARB, NRCS, and U.S. EPA signed a Statement of Principles to work collaboratively to develop a mechanism to provide SIP credit for investments made in the San Joaquin Valley by the agriculture industry to clean up mobile agricultural equipment through local, state, and federally funded incentive programs. This regulatory action is the outcome of this Statement of Principles.

Arising from the Statement of Principles, SJVAPCD developed *Rule 9610 State Implementation Plan for Emission Reductions Generated Through Incentive Programs* (Rule 9610) that was approved by their Governing Board on June 20, 2013. Rule 9610 provides administrative requirements for local, state, and federal voluntary incentive programs in the San Joaquin Valley to ensure that emission reductions will be eligible to receive SIP credit.

The Proposed Regulation for *State Implementation Plan Credit from Mobile Agricultural Equipment* would complement Rule 9610 by providing an administrative mechanism to ensure that incentive-funded mobile agricultural equipment projects implemented using the Carl Moyer Program Guidelines and administered by SJVAPCD result in emission reductions that are eligible to receive SIP credit.

Overall, both the ARB regulation and Rule 9610 combined would ensure that all SIP creditable emission reductions from incentive-funded mobile agricultural equipment projects (regardless of funding source) are coordinated and accounted for. This proposed regulation would also provide for an opt-in for any other air district in California that complies with the requirements of the proposed regulation; the opt-in district's local rule must have mobile agricultural equipment emission reductions resulting from incentive programs that follow the Carl Moyer Program Guidelines to be eligible to be considered for SIP credit.

Description of the Proposed Regulatory Action, Objective, and Benefits:

Proposed Regulatory Action:

To be eligible for SIP credit, ARB's proposed regulation requires that mobile agricultural equipment incentive projects follow the Carl Moyer Program Guidelines. To ensure accountability, ongoing program reviews and audits by the air district will be required to verify project data, application information, emission reductions, destruction verification, and retention of application, inspection, destruction, and other project-related documentation consistent with the Carl Moyer Program Guidelines.

Carl Moyer Program emission reductions are surplus, quantifiable, enforceable, and permanent, and are consistent with U.S. EPA guidance for SIP creditability of incentive funded projects. This proposed regulation would also allow an opt-in for any other air district in California that complies with the requirements of the proposed regulation to have mobile agricultural equipment emission reductions that result from incentive programs that follow the Carl Moyer Program Guidelines be eligible to be considered for SIP credit.

Objective: Administrative Mechanism for State Implementation Plan Credit for Incentive Plans Following Carl Moyer Program Guidelines:

This proposed rulemaking provides an administrative mechanism to ensure emission reductions from voluntary incentive programs implemented following the Carl Moyer Program Guidelines are eligible for SIP credit and can be used towards meeting a SIP commitment. The proposed regulation is intended to complement SJVAPCD's Rule 9610, which provides administrative requirements on local, state, and federal voluntary incentive programs in the San Joaquin Valley to ensure that emission reductions will be eligible to receive SIP credit.

Benefits:

The proposed regulation ensures that ARB will meet the 2007 SIP commitment to bring to the Board a measure for mobile agricultural equipment in the San Joaquin Valley. Staff estimates that the emission reductions that will be eligible for SIP credit as a result of the proposed regulation will meet the 2007 SIP goal for NOx emission reductions of 5 to 10 tons per day by 2017 to accelerate clean air progress.

DETERMINATION OF INCONSISTENCY AND INCOMPATIBILITY WITH EXISTING STATE REGULATIONS

During the process of developing the proposed regulatory action, ARB has conducted a search of any similar regulations on this topic and has concluded that these regulations are neither inconsistent nor incompatible with existing state regulations.

COMPARABLE FEDERAL REGULATIONS

There are no comparable federal regulations.

STATE IMPLEMENTATION PLAN REVISION

If adopted, ARB plans to submit the proposed regulatory action to U.S. EPA for approval as a revision to the California SIP required by the federal Clean Air Act (CAA). The adopted regulatory action would be submitted as a SIP revision because it adopts regulations intended to reduce emissions of air pollutants in order to attain and maintain National Ambient Air Quality Standards promulgated by U.S. EPA pursuant to the CAA.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The report is entitled: Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment.

Copies of the ISOR and the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, may be

accessed on ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990, on Wednesday, October 9, 2013.

Final Statement of Reasons Availability

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on ARB's website listed below.

Agency Contact Persons

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Ms. Lynsay Carmichael, Resources Engineer, at (916) 322-0407 or Mr. Tim Hartigan, Air Pollution Specialist, at (916) 324-0202.

Further, the agency representative, to whom nonsubstantive inquiries concerning the proposed administrative action may be directed to Ms. Trini Balcazar, Regulations Coordinator, (916) 445-9564. The Board staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

Internet Access

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at http://www.arb.ca.gov/regact/2013/sipmobileag2013/sipmobileag2013.htm

DISCLOSURES REGARDING THE PROPOSED REGULATION

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Fiscal Impact / Local Mandate

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would create no administrative costs to ARB, SJVAPCD, or other opt-in air districts by implementing the regulation. The expenses represent no additional workload to current administrative activities and therefore are covered through normal administration budgets. The proposed regulatory action would not create costs or savings to any other State agency, or in federal funding to the State, costs or mandate to any local agency or school district whether or not reimbursable by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, or other nondiscretionary cost or savings to State or local agencies.

Significant Statewide Adverse Economic Impact Directly Affecting Business, Including Ability to Compete

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons.

Cost Impacts on Representative Private Persons or Businesses

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses. ARB is not aware of any cost impacts that a representative private person or business would necessarily incur in reasonable compliance with the proposed action.

Results of The Economic Impact Analysis/Assessment Prepared Pursuant to Government Code Sec. 11346.3(b)

Effect on Jobs/Businesses:

The Executive Officer has determined that the proposed regulatory action would not affect the creation or elimination of jobs within the State of California, the creation of new businesses or elimination of existing businesses within the State of California, or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

Benefits of the Proposed Regulation:

The objective of the proposed regulation is to provide an administrative mechanism to ensure emission reductions from mobile agricultural equipment voluntary incentive programs implemented by SJVAPCD following the Carl Moyer Program Guidelines are eligible for SIP credit and can help meet the 2007 SIP goal of reducing NOx emissions in the San Joaquin Valley by 5 to 10 tons per day by 2017 to accelerate air quality progress. Other California air districts that opt-in per the requirements of the proposed regulation would also be eligible for SIP credit for mobile agricultural equipment voluntary incentive programs that follow the Carl Moyer Program Guidelines.

Effect on Small Business

The Executive Officer has also determined, pursuant to California Code of Regulations, title 1, section 4, that the proposed regulatory action would not affect small businesses because the regulated party, SJVAPCD or Districts that opt-in, does not fall under the category of "small business."

Housing Costs

The Executive Officer has also made the initial determination that the proposed regulatory action will not have a significant effect on housing costs.

Alternatives

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons than the proposed action, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provision of law. Staff considered two alternatives to the proposed regulation. One alternative considered was "No Regulation", that is, refrain from establishing a mechanism for mobile agricultural equipment voluntary incentive programs and projects to demonstrate emission reductions that can be eligible to receive SIP credit. The second alternative considered was a "Require Turnover to New Technology" alternative that requires the mobile agricultural fleet in the San Joaquin Valley to turn over to the cleanest technology by a set compliance schedule. A more detailed analysis of the alternatives considered for the regulation can be found in *ISOR Chapter VI, Economic Impacts*.

Environmental Analysis

In accordance with ARB's certified regulatory program, California Code of Regulations, title 17, sections 60006 through 60007, and the California Environmental Quality Act, Public Resources Code section 21080.5, ARB has conducted an analysis of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulatory action. The environmental analysis of the proposed regulatory action can be found in *ISOR Chapter IV, Environmental Impacts Analysis*.

WRITTEN COMMENT PERIOD AND SUBMITTAL OF COMMENTS

Interested members of the public may present comments orally or in writing at the meeting and may provide comments by postal mail or by electronic submittal before the meeting. The public comment period for this regulatory action will begin on **Monday, September 9, 2013**. To be considered by the Board, written comments not physically submitted at the meeting, must be submitted on or after **Monday, September 9, 2013** and received **no later than 12:00 noon on Wednesday, October 23, 2013**, and must be addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

You can sign up online in advance to speak at the Board meeting when you submit an electronic board item comment. For more information go to: http://www.arb.ca.gov/board/online-signup.htm

Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

ARB requests that written and email statements on this item be filed at least 10 days prior to the hearing so that ARB staff and Board members have additional time to consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

Additionally, the Board requests but does not require that persons who submit written comments to the Board reference the title of the proposal in their comments to facilitate review.

AUTHORITY AND REFERENCE

This regulatory action is proposed under the authority granted in Health and Safety Code, sections 39001, 39003, 39500, 39515, 39516, 39600, 39601, 39602, 39602.5, 39659, 43000, 43000.5, and 44291. This action is proposed to implement, interpret, and make specific sections 39002, 39515, 39516, 39600, 39601, 39602, 39602.5, 39650, 39656, 39657, 39658, 39659, 43000, 43000.5, and 43018.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, Government Code, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340).

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice and that the regulatory language as modified could result from the proposed regulatory action; in such event, the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15-days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Consistent with California Government Code Section 7296.2, special accommodation or language needs may be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Consecuente con la sección 7296.2 del Código de Gobierno de California, una acomodación especial o necesidades lingüísticas pueden ser suministradas para cualquiera de los siguientes:

- Un intérprete que esté disponible en la audiencia
- Documentos disponibles en un formato alterno u otro idioma
- Una acomodación razonable relacionados con una incapacidad

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envié un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California..

CALIFORNIA AIR RESOURCES BOARD

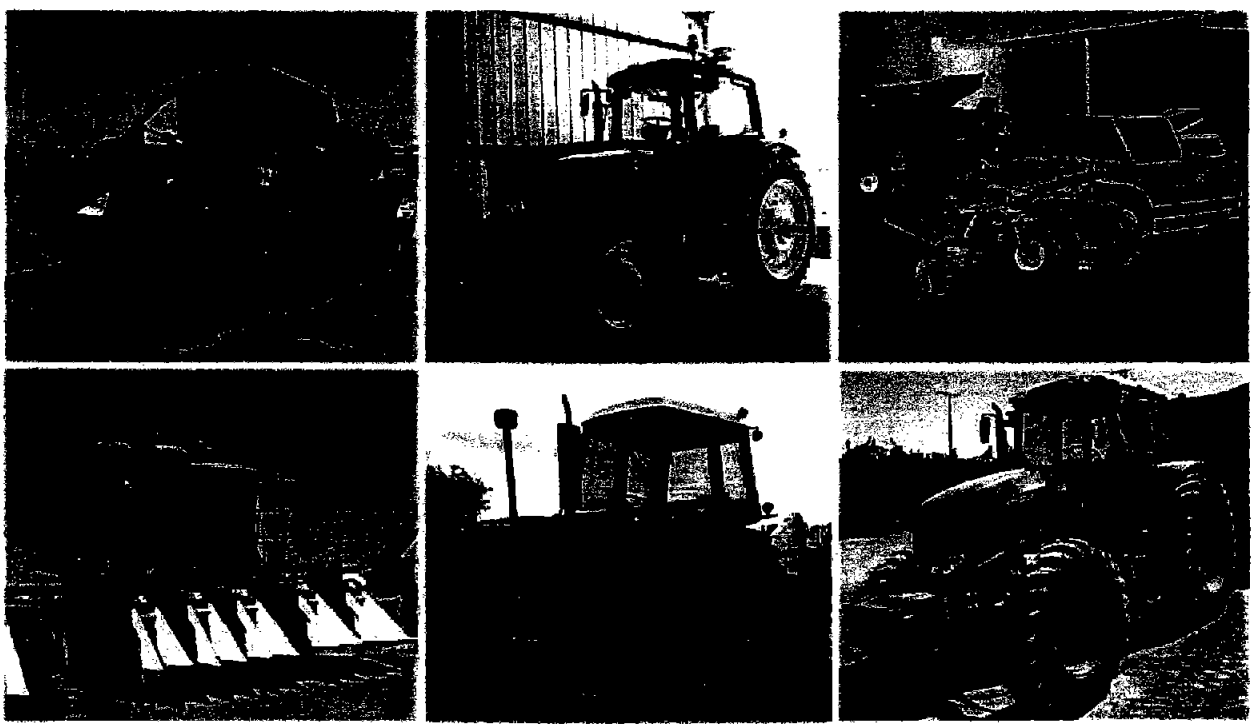
Richard W. Corey
Executive Officer

Date: August 27, 2013

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website at www.arb.ca.gov.

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING



PROPOSED REGULATION FOR STATE IMPLEMENTATION PLAN CREDIT FROM MOBILE AGRICULTURAL EQUIPMENT

Date of Release: September 4, 2013
Scheduled for Consideration: October 24, 2013

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the California Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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EXECUTIVE SUMMARY

The California Air Resources Board (ARB or the Board) is responsible for protecting public health and the environment from the harmful effects of air and climate pollution. ARB oversees all air pollution control efforts in California, including activities of California's 35 local air pollution control districts and air quality management districts (air districts). The San Joaquin Valley Air Pollution Control District (SJVAPCD) is one of California's largest local air districts and is responsible for air quality in the San Joaquin Valley. Per federal Clean Air Act (CAA) National Ambient Air Quality Standards (NAAQS), the San Joaquin Valley is designated as extreme nonattainment for ozone and nonattainment for fine particulate matter (PM2.5).

The San Joaquin Valley is the most productive agricultural area in the world, and emissions associated with diesel-powered off-road mobile agricultural equipment are a significant contributor to the region's air pollution problem. Diesel-powered mobile agricultural equipment emits oxides of nitrogen (NOx), a precursor to ozone formation. Medical studies of large populations have found that ozone exposure is associated with an increase in hospital admissions and emergency room visits, particularly for lung problems such as asthma and chronic obstructive pulmonary disease.

Federal clean air laws require areas with unhealthy levels of ozone, inhalable particulate matter, carbon monoxide, nitrogen dioxide, and sulfur dioxide to develop plans, known as State Implementation Plans (SIP). SIPs are comprehensive plans that describe how an area will attain NAAQS by the applicable deadlines. In 2007, SJVAPCD developed a SIP to meet the 0.08 parts per million (ppm) 8-hour ozone standard by 2023. The 2007 SIP, which was approved by United States Environmental Protection Agency (U.S. EPA) in December 2011, contains a measure for mobile agricultural equipment which sets a goal to achieve emissions reductions of 5 to 10 tons per day of NOx in the San Joaquin Valley by 2017 in order to accelerate air quality progress. In 2016, another SIP will be due to address the more stringent 2008 ozone standard with and attainment deadline of 2032.

ARB incentive-based air quality programs are designed to achieve near- and long-term emission reductions through investments in cleaner technologies. These programs include the Carl Moyer Program, Assembly Bill 118 - Air Quality Improvement Program, Proposition 1B Goods Movement Program, and Proposition 1B Lower-Emission School Bus Program. Each of these programs address specific air quality priorities, such as the early replacement of older vehicles and engines with newer, cleaner engines and the development and deployment of cleaner vehicle and equipment technology. The success of these programs helps California accelerate progress toward achieving health-based air quality standards, prevents federal sanctions such as the loss of federal highway funds, and assists businesses with equipment upgrades prior to regulatory requirements (with cost-sharing to leverage private funding for all projects).

In particular, since 1998, ARB's Carl Moyer Program has funded the extra capital cost of cleaner-than-required vehicles and equipment to help achieve air pollution reductions that are both early and surplus to regulations. Funds for the Carl Moyer Program include tire replacement and vehicle registration (smog abatement) fees. The Carl Moyer Program provides incentives to private and public agencies to voluntarily clean up older, dirtier vehicles and mobile off-road engines through retrofit or replacement. ARB develops statewide implementation guidelines, distributes funds to air districts, and conducts periodic oversight. Air districts choose which project types to fund from a variety of eligible categories, including on-road and off-road vehicles and equipment, marine, shore power, locomotives, stationary agriculture pumps, emergency equipment, lawn and garden equipment, and light duty vehicle scrap. Funded projects must achieve early or extra emission reductions not otherwise required by law or regulation. SJVAPCD (like other large and medium-sized air districts) contributes match funds as required by the Carl Moyer Program.

SJVAPCD has partnered with ARB from the inception of the Carl Moyer Program and has used the Carl Moyer Program as a model for other local funded programs. As demonstrated through multiple reviews and audits, SJVAPCD's incentive programs are highly efficient and effective.[1] SJVAPCD's voluntary incentive programs fund cleaner-than-required engines and equipment and are a crucial component of the SJVAPCD's efforts to reduce emissions and meet air quality standards. Since the adoption of the 2007 SIP, the agricultural industry has worked collaboratively with the SJVAPCD and the U.S. Department of Agriculture Natural Resource Conservation Service (NRCS) to procure and expend federal, state and local funds to reduce pollution by accelerating the turnover of older, dirtier mobile agricultural equipment with the cleanest available technologies, which for mobile agricultural equipment is primarily comprised of Tier 3 and cleaner off-road engines. U.S. EPA has provided guidance on incorporating voluntary measures, such as these incentive programs, into SIPs. To meet U.S. EPA criteria for SIP creditability of incentive funded projects, the emission reductions must be surplus, quantifiable, enforceable, and permanent.

In 2010, SJVAPCD, ARB, NRCS, and U.S. EPA signed a Statement of Principles[2] to work collaboratively to develop a mechanism to provide SIP credit for investments made in the San Joaquin Valley by the agriculture industry to clean up mobile agricultural equipment through local, state, and federal funded incentive programs. This regulatory action is the outcome of this Statement of Principles.

Arising from the Statement of Principles, SJVAPCD developed *Rule 9610 State Implementation Plan for Emission Reductions Generated Through Incentive Programs*

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[1] ARB Incentive Program Oversight webpage, http://www.arb.ca.gov/msprog/moyer/audits/audits.htm; http://www.arb.ca.gov/msprog/moyer/audits/2011/sjvarbprogramreview.pdf; http://www.arb.ca.gov/msprog/moyer/audits/2011/sjvdofreview.pdf; http://www.arb.ca.gov/msprog/moyer/audits/2007/sjvapcd_final_report.pdf; http://www.arb.ca.gov/msprog/moyer/audits/2007/dof_sjv_report.pdf

[2] Appendix B, Statement of Principles—December 2010

(Rule 9610)[3] that was approved by their Governing Board on June 20, 2013. Rule 9610 provides administrative requirements for local, state, and federal voluntary incentive programs in the San Joaquin Valley to ensure that emission reductions will be eligible to receive SIP credit.

This proposed regulation, *State Implementation Plan Credit from Mobile Agricultural Equipment,*[4] meets ARB's commitment in the 2007 SIP for a mobile agricultural equipment regulation by providing an administrative mechanism to ensure that incentive funded projects (regardless of funding source) implemented using Carl Moyer Program Guidelines are surplus, quantifiable, enforceable, and permanent, and result in emission reductions that are eligible for SIP credit. U.S. EPA guidance regarding SIP credit for incentive program emission reductions, *Improving Air Quality with Economic Incentive Programs,*[5] describe the same "Integrity Elements," i.e., they must be surplus, quantifiable, enforceable, and permanent. This regulation will complement the SJVAPCD's Rule 9610, and ensure that emission reductions achieved through incentive programs are eligible for SIP credit when quantified and included in a SIP amendment adopted by the ARB and approved by U.S. EPA in accordance with the requirements of CAA. The incentive funded projects implemented by SJVAPCD using Carl Moyer Program Guidelines per this proposed regulation result in SIP creditable emission reductions that help meet the 2007 SIP goal of 5 to 10 tons per day of NOx reductions by 2017. The proposed regulation imposes no administrative costs to ARB, SJVAPCD, and air districts that opt in to participate.

While ARB and the SJVAPCD continue to implement the 2007 SIP, U.S. EPA revised the 8-hour ozone standard in 2008, lowering the level to 0.075 ppm. A new SIP for the revised 8-hour ozone standard will be developed for submittal to U.S. EPA in 2016. This SIP will address additional reductions needed in the San Joaquin Valley to attain the more stringent standard with an attainment deadline of 2032. This plan will require a comprehensive strategy for emission reductions and apply to many source categories. To meet the longer-term emission reductions needs identified in that plan, staff has initiated a second and concurrent regulatory development process for mobile agricultural equipment. Strategies for this second effort will rely on continued use of voluntary incentive programs, the availability and increased use of the cleanest technologies for mobile agricultural equipment (primarily Tier 4 equipment), and equipment trade-up programs.

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[3] Appendix C, San Joaquin Valley Air Pollution Control District Rule 9610 — *State Implementation Plan Credit for Emission Reductions Generated Through Incentive Programs* — June 20, 2013

[4] Appendix A: Proposed Regulation for *State Implementation Plan Credit from Mobile Agricultural Equipment*

[5] U.S. EPA, Office of Air and Radiation (January 2001), *Improving Air Quality with Economic Incentive Programs*, EPA-452/R-01-001, pages 35-44, http://www.epa.gov/ttn/oarpg/t1/memoranda/eipfin.pdf

I. INTRODUCTION AND BACKGROUND

A. Need for Cleaner Air in the San Joaquin Valley

ARB is the State agency responsible for protecting public health and the environment from the harmful effects of air pollution. ARB oversees all air pollution control efforts in California, including the activities of 35 local air districts. ARB works in cooperation with the air districts and U.S. EPA on strategies to attain state and federal standards and to reduce toxic air emissions. SJVAPCD is the local government agency primarily responsible for air quality assessment and improvement in the San Joaquin Valley.

Off-road mobile agricultural equipment is a significant source of emissions in the San Joaquin Valley and in particular, NOx, a precursor to ozone and particulate matter formation. Ozone is a highly reactive gas that forms in the atmosphere through complex reactions between chemicals directly emitted from motor vehicles, industrial plants, consumer products and many other sources. Studies have consistently shown that inhalation of ozone can lead to inflammation and irritation of the tissues lining the human airways. This causes the muscle cells in the airways to spasm and contract, thus reducing the amount of air that can be inhaled. Symptoms and responses to ozone exposure vary widely, even when the amount inhaled and length of exposure is the same. Typical symptoms include cough, chest tightness, and increased asthma symptoms. Medical studies of large populations have found that ozone exposure is associated with an increase in hospital admissions and emergency room visits, particularly for lung problems such as asthma and chronic obstructive pulmonary disease. Several studies have also associated ozone exposure with increased premature mortality in elderly people with chronic diseases of the lungs and circulatory system.[6]

B. California's Agricultural Industry and Mobile Agricultural Equipment in the San Joaquin Valley

California's agricultural industry consists of over 81,000 farms growing and producing over 400 different commodities, making agriculture one of the State's most diverse industries.[7] Producers, custom operators, first processors, and rental companies in the agricultural industry own and operate approximately 160,000 pieces of mobile agricultural equipment Statewide. This equipment is defined as diesel-fueled, self-propelled, off-road equipment or vehicles with greater than 25 horsepower that are used in agricultural operations. Approximately 76 percent of the population are tractors and 24 percent consist of harvesters, loaders, sprayers, conditioners, balers, cotton pickers and other specialized equipment types. Some types of non-tractor mobile agricultural equipment have

[6] *Air Resources Board's Proposed State Strategy for California's 2007 State Implementation Plan,* http://arb.ca.gov/planning/sip/2007sip/apr07draft/sipback.pdf

[7] *California Agricultural Production Statistics,* http://www.cdfa.ca.gov/statistics

unique and specific roles within an operation based on the commodity being produced and usually require specialized functions of the equipment. Non-tractors often have unalterable roles that are specific to certain functions and limit their usefulness for alternate operations, causing non-tractors to be significantly more expensive than tractors. The large expense deters operators from replacing and purchasing specialized equipment which leads to a higher prevalence of older, more polluting equipment within the specialized mobile agricultural equipment population. Some examples of mobile agricultural equipment are shown below:

Figure I-1 Tractor

Figure I-2 Loader

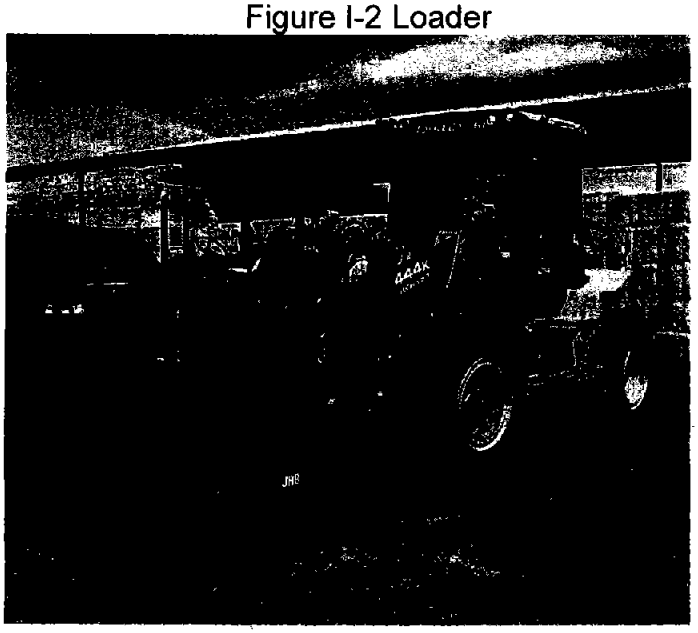


Figure I-3 Combine Harvester

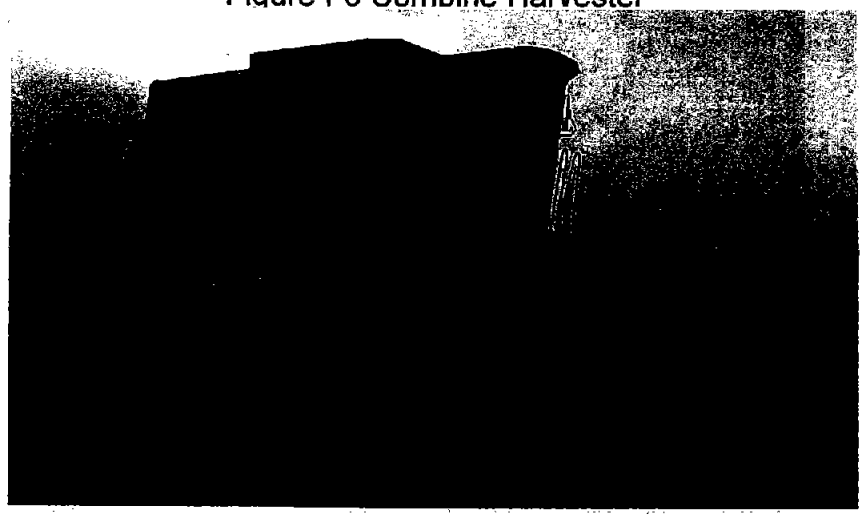


Figure I-4 Almond Harvester

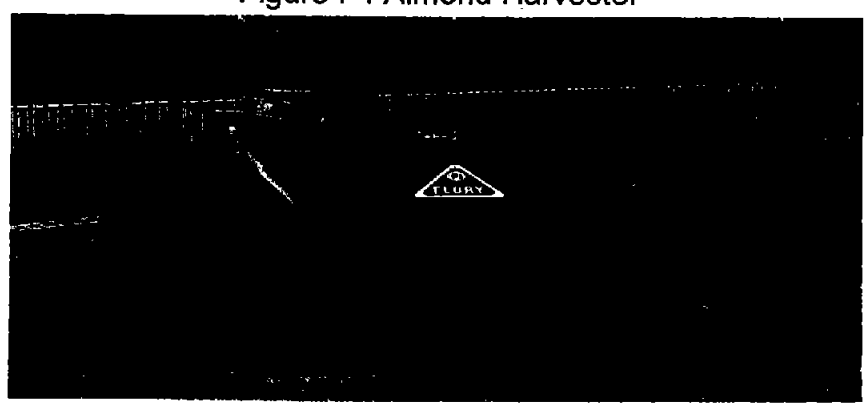


Figure I-5 Sprayer

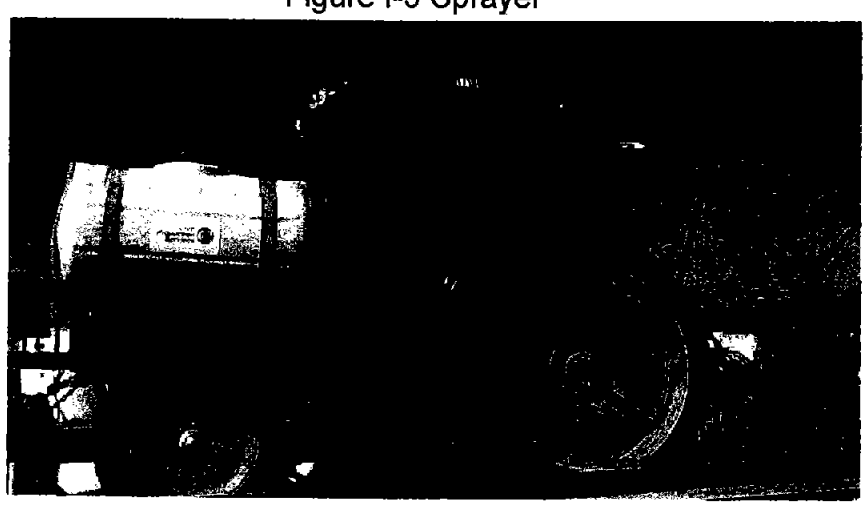
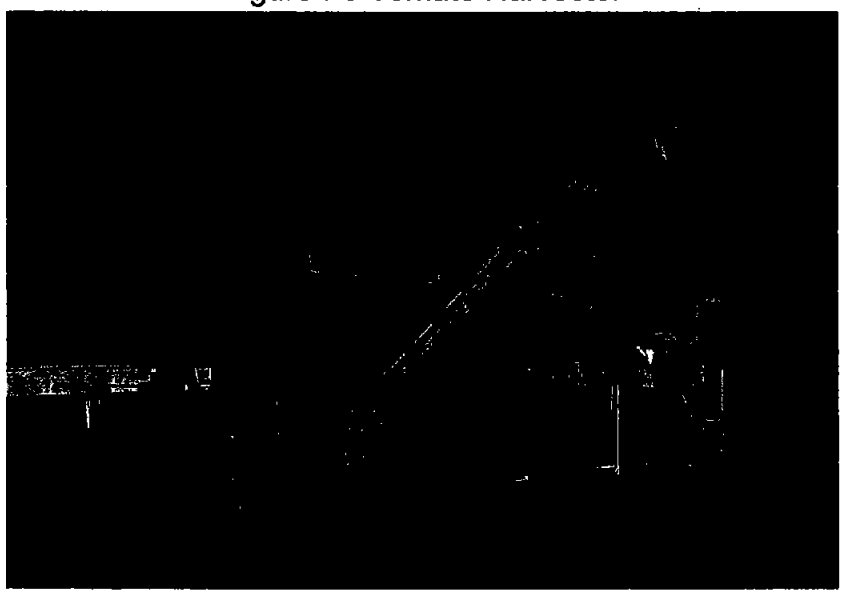


Figure I-6 Tomato Harvester



In the San Joaquin Valley, mobile agricultural equipment plays a significant role in the air quality challenges as the region has a large agricultural economy. In the current emissions inventory, mobile agricultural equipment accounts for over 13 percent of the total NOx emissions and about 2 percent of the total PM2.5 emissions from mobile sources in the San Joaquin Valley.[8] Although the increasingly stringent U.S. EPA new engine standards for off-road equipment will reduce emissions from mobile agricultural equipment over time, most mobile agricultural equipment is operated for several decades before being retired due to their durability and relatively low cost to maintain. Thus, natural turnover is not sufficient to meet the San Joaquin Valley's near-term clean air needs. As a result, additional early emission reductions from mobile agricultural equipment are needed as an important part of California's strategy to meet NAAQS in the San Joaquin Valley.

In the 2007 SIP, ARB included a commitment to take a measure to the Board to clean up mobile agricultural equipment in the San Joaquin Valley with a goal of achieving reductions of 5 to 10 tons per day of NOx by 2017 to accelerate air quality progress. The overall goal of the measure was to encourage turnover of the mobile agricultural fleet in San Joaquin Valley to the cleanest Tier 4 final equipment. Staff recognized, however, that Tier 4 final equipment may not yet be widely available and that significant reductions can be achieved sooner by upgrading dirty, older equipment now to Tier 3. The measure acknowledged a role for incentive programs and the public health benefit of early voluntary actions. The measure is being implemented through the comprehensive incentive programs in place in the San

[8] California Emissions Projection Analysis Model (CEPAM)
http://outapp.arb.ca.gov/cefs/norcal2012pm25sip/

Joaquin Valley. ARB staff have estimated the benefits to be in the range of 5 to 10 tons per day by 2017.

C. Progress Toward Cleaner Air in San Joaquin Valley Through Voluntary Incentive Program Mobile Agricultural Equipment Projects

Since the adoption of the 2007 SIP, the agricultural industry, SJVAPCD, and NRCS have worked collaboratively to procure and expend federal, state and local funds to reduce pollution by accelerating the turnover of older, dirtier mobile agricultural equipment with the cleanest available technologies (primarily Tier 3 and cleaner off-road engines in mobile agricultural equipment). In a Statement of Principles signed by ARB, U.S. EPA, NRCS, and SJVAPCD in 2010, the agencies agreed to work in partnership to develop a mechanism to ensure that the early emission reductions resulting from these voluntary incentive programs be eligible to receive SIP credit. ARB's proposed regulatory action is the outcome of this Statement of Principles.

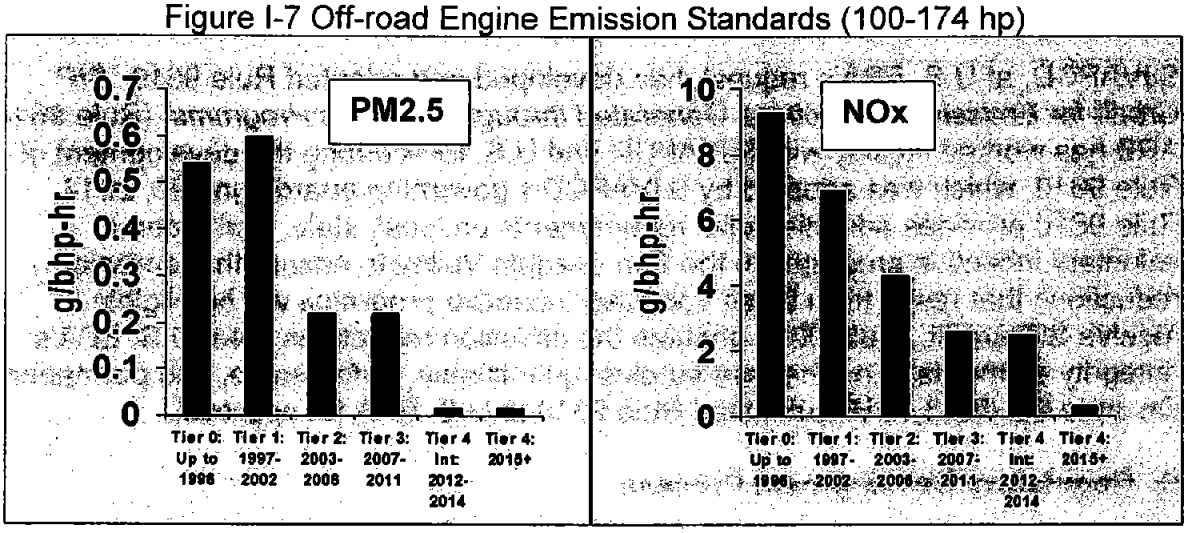
SJVAPCD, at U.S. EPA's request, has developed and adopted Rule 9610 "*SIP Credit for Emission Reductions Generated through Incentive Programs*" (Rule 9610). ARB has worked closely with SJVAPCD and U.S. EPA during the development of Rule 9610, which was adopted by SJVAPCD's governing board June 20, 2013. Rule 9610 provides administrative requirements on local, state, and federal voluntary incentive programs in the San Joaquin Valley to ensure that emission reductions that result from these voluntary incentive programs will be eligible to receive SIP credit. Rule 9610 ensures the emission reductions meet U.S. EPA's "integrity elements", i.e., they are surplus, quantifiable, enforceable, and permanent. On June 26, 2013, ARB submitted Rule 9610 to U.S. EPA for approval.

D. Regulatory Development Process

In 2012, ARB staff began the regulatory development process for mobile agricultural equipment to be eligible to receive SIP credit. This process included gaining a thorough understanding of the unique economy and operational characteristics of mobile agricultural equipment in the agricultural industry, continuing to collect additional data for updating the emissions inventory work that began in 2008, and reviewing and analyzing the cost and availability of Tier 4 technologies for mobile agricultural equipment. The goal at the beginning of this regulatory process was to develop one regulation that would meet the 2007 SIP emission reduction goal for 2017 and attainment of the 1997 ozone standard by 2023, while also addressing the actions required to meet the new, more stringent 8-hour ozone standard by 2032. Over the course of this process, however, it became clear that a two-step regulatory process that ensures SIP credit for voluntary incentive program mobile agricultural projects in the near-term and a longer-term effort to accelerate use of Tier 4 equipment would better serve to maximize the air quality benefits over time while also meeting the 2007 SIP goal for 2017 and 2023.

Staff reviewed and analyzed U.S. EPA and California new engine standards and how the standards are currently being met by engine manufacturers and Original Equipment Manufacturers (OEM). Flexibility and emission credit banking provisions available to the engine manufacturers and OEMs allow for the delayed production and introduction of the cleanest Tier 4 final engine technologies. Staff estimate that cleaner engine technologies will not be introduced for all mobile agricultural equipment applications until about the 2020-timeframe (see Section J below). Until that time, encouraging the mobile agricultural fleet in the San Joaquin Valley to upgrade now with the cleanest technologies currently available, typically Tier 3, offers significant early air pollution reduction benefits. Figure I-7, below, compares emissions standards associated with different Tier engine designations for off-road diesel equipment, and illustrates the significant PM2.5 and NOx reductions achieved by Tier 3 equipment (for 100 to 174 horsepower engines) and the even more substantial reductions that Tier 4 final equipment achieves. Recognizing this, ARB is proposing two rulemakings for mobile agricultural equipment.

Figure I-7 Off-road Engine Emission Standards (100-174 hp)



The first proposed regulation, which is complementary to SJVAPCD's Rule 9610 and outlined in this staff report *State Implementation Plan Credit for Mobile Agricultural Equipment,* provides an administrative mechanism to ensure that incentive funded mobile agricultural projects implemented by SJVAPCD using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. To ensure accountability, SJVAPCD must conduct ongoing project monitoring per the Carl Moyer Program Guidelines. ARB will continue to oversee the Carl Moyer Program by managing program funds; developing and revising guidelines, protocols, and criteria for covered vehicle projects including mobile agricultural equipment; and determining methodologies used for evaluating project cost-effectiveness. Other air districts can opt-in if they comply with the requirements of this proposed regulation.

The outcome of the proposed regulation is SJVAPCD and other air districts that opt-in could be eligible to receive SIP credit for mobile agricultural equipment projects, regardless of funding source, implemented using the Carl Moyer Program

Guidelines. Furthermore, emission reductions from voluntary incentive program mobile agricultural equipment projects in the San Joaquin Valley would be eligible to assist in meeting the 2007 SIP goal of achieving 5 to 10 tons per day of NOx reductions and accelerate progress toward clean air.

Following this rulemaking, a second ARB rulemaking will be developed concurrently with the 2016 SIP for the San Joaquin Valley that will address a new, more stringent 8-hour ozone standard. This 2016 SIP will address additional reductions needed to attain the 2008 standard by the 2032 deadline, likely achieved through strategies that will include relying on the availability of the cleanest technologies in mobile agricultural equipment (Tier 4 final).

E. Proposed Regulation for *State Implementation Plan Credit from Mobile Agricultural Equipment*

The proposed regulation provides an administrative mechanism to ensure that incentive funded projects implemented using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. Using Carl Moyer Program Guidelines ensures these programs produce emission reductions that are surplus, quantifiable, enforceable, and permanent, and meet U.S. EPA guidance for SIP creditability of incentive funded projects. As a result, this proposed regulation will ensure that the substantial investments made by the public sector and by the agricultural industry in the San Joaquin Valley through participation in mobile agricultural equipment projects funded by voluntary incentive programs result in emission reductions that are eligible to receive SIP credit. The emission reductions generated through the NRCS incentive program in the San Joaquin Valley will be eligible for SIP credit through SJVAPCD's Rule 9610. Other California air districts can opt-in to have incentive program mobile agricultural equipment projects receive SIP credit if they comply with the requirements of this proposed regulation.

F. Authority for this Proposed Regulation

ARB has been granted both general and specific authority under the Health and Safety Code (HSC) to adopt the proposed regulation. HSC Sections 39600, 39601, and 39602.5 confer on ARB the general authority and obligation to adopt rules and measures necessary to execute the Board's powers and duties imposed by State law and to attain federal NAAQS in all areas by applicable attainment dates. Also, HSC Section 39602 provides ARB authority to coordinate the activities of the air districts to comply with CAA.

G. Statutory Requirement for SIPs

Section 172 of CAA requires that each state develop a SIP for areas designated as in nonattainment of the primary and secondary NAAQS. The SIP is a plan for each state that contains control measures and strategies which demonstrate how each area will attain and maintain the NAAQS.

The 2007 San Joaquin Valley 8-Hour Ozone SIP, approved by U.S. EPA in December 2011, contains a commitment by ARB to present to the Board a regulation for mobile agricultural equipment.

H. U.S. EPA's Guidance on Voluntary Reductions

U.S. EPA has provided guidance on emission reductions from voluntary incentive programs. To be eligible for SIP credit, emission reductions from these programs must be surplus, quantifiable, enforceable, and permanent. The following describes how the four elements apply to the proposed regulation:

Surplus
Carl Moyer Program Guidelines ensure the resulting emission reductions for mobile agricultural equipment are not otherwise required by any federal, state, or local regulation or other legal mandate. The emission reductions must also be in excess of the SIP baseline emission levels; meaning the emission reductions must be in excess of the base year, attainment year, and progress milestone year emissions forecasts that include adopted regulations.

Quantifiable
Carl Moyer Program Guidelines ensure that emission reductions can be reliably determined through the use of well-established, publicly available emission factors and calculation methodologies. Emission reduction calculation methodologies in the Carl Moyer Program Guidelines for mobile agricultural equipment are well-established, use publicly available emission factors that were generated from ARB's Mobile Source Emission Inventory off-road model, and can be replicated by the public.

Enforceable
Carl Moyer Program Guidelines ensure that emission reductions achieved through funded projects are enforceable. The Carl Moyer Program Guidelines require that emission reductions must be independently and practicably verifiable for the duration of the project life through inspections, monitoring, and other mechanisms. Furthermore, incentive program violations are defined through legally binding contracts, grants, or vouchers that identify the party or parties responsible for ensuring that emission reductions are achieved. Funding recipients of voluntary incentive program funds are also obligated to provide all records needed to demonstrate that emission reductions are achieved. All emission-related information for reductions claimed must be available for public access.

Permanent

Carl Moyer Program Guidelines ensure that emission reductions are made permanent for the duration of the project life by requiring that existing (baseline) equipment or vehicles are physically destroyed or permanently disabled, or to permanently amend practices to ensure reductions for the duration of the project life.

I. Existing Air Quality Voluntary Incentive Programs

Since 2008, over 2,500 pieces of mobile agricultural equipment have been replaced through several voluntary incentive programs in the San Joaquin Valley. Staff estimates that these and future projects resulting from continued funding will be sufficient to meet the SIP goal of reductions of 5 to 10 tons of NOx by 2017. When the San Joaquin Valley ozone SIP is updated in 2016, the benefits of incentive programs will be quantified and documented using the mechanism specified in this proposed regulation. Below is a summary of the existing voluntary incentive programs that fund mobile agricultural equipment replacement in the San Joaquin Valley. ARB will continue supporting efforts to secure additional and new sources of federal, state, and local funds to continue achieving early emission reductions that can be credited to the SIP.

Carl Moyer Memorial Air Quality Standards Attainment Program
The Carl Moyer Program has provided $7 million in grant funding for over 180 cleaner-than-required agricultural equipment and engine replacements since 2008 in the San Joaquin Valley. Emission reductions from the Carl Moyer Program projects are SIP creditable; this proposed regulation provides the administrative mechanism to receive those credits. Carl Moyer Program grants are administered by air districts. ARB works collaboratively with the air districts and other stakeholders to set guidelines and ensure the program results in projects that reduce air pollution, achieving early reductions in emissions of key pollutants that are necessary for California to meet its clean air commitments under regulatory requirements. Funding the replacement, repower or retrofit of mobile agricultural equipment is an approved source category in the Carl Moyer Program.

SJVAPCD Agricultural Tractor / Mobile Equipment Replacement Program
SJVAPCD's Agricultural Tractor / Mobile Equipment Replacement Program provides incentive funds for the replacement of in-use, off-road mobile equipment that is engaged in agricultural operations as defined by ARB. The program follows the Heavy-Duty Engine Program, Off-Road Vehicle Component, Agricultural Tractor/Mobile Equipment Replacement Option, Eligibility Criteria, and Application Guidelines, which are modeled after Carl Moyer Program Guidelines. These emission reductions will be able to receive SIP credit through SJVAPCD's Rule 9610. As of

March 2013, the program had allocated over $26 million in grant funding to replace over 1,000 pieces of agricultural equipment.

NRCS, Environmental Quality Incentive Program (EQIP)
EQIP is a federally funded and implemented program that provides financial assistance to implement approved conservation practices to address significant air quality resource concerns for designated high priority geographic locations throughout the nation, specifically states and counties which are designated as non-attainment according to Clean Air Act requirements. In order to help California meet its NAAQS, NRCS established the California Air Quality Initiative through the 2008 Farm Bill to award payment assistance to projects that provide significant environmental benefits. The San Joaquin Valley's eight counties are included in this designation and received $72 million in funding for over 1,300 mobile off-road agricultural equipment replacements through NRCS EQIP from 2009 through 2012. These emission reductions will be able to receive SIP credit through SJVAPCD's Rule 9610. The program operates using the EQIP Guidelines, Policies, and Procedures-Combustion Systems Improvement (Code 372) which were developed using the Carl Moyer Program Guidelines.

J. Delayed Availability of Cleaner Technologies

On May 11, 2004, U.S. EPA adopted Tier 4 standards that require additional reductions of PM and NOx from exhaust emissions for off-road engines, including engines used in mobile agricultural equipment, with the emission standards being phased-in over the period between 2008 and 2015. California adopted equivalent emission standards in 2004. New off-road engine emission standards are effective on January 1 of each year beginning in 2008 through 2015 (by power categories). For example, January 1, 2013, is the effective compliance date for the Tier 4 final emission standards for engines between 25 and 75 horsepower.[9] Off-road engine manufacturers will use a variety of technologies to meet these emission standards including, but not limited to one or more of the following: improved engine design, advance exhaust gas after-treatment, selective catalytic reduction, exhaust gas recirculation, diesel particle filter, or diesel oxidation catalyst.

The new engine regulations include options available to engine manufacturers and OEMs to help enable them to meet these engine standards. Flexibilities in the regulation include U.S. EPA's Average, Banking and Trading Program (ABT) for engine manufacturers and Transition Program for Equipment Manufacturers (TPEM) for OEMs. For engine manufacturers using ABT, engine families are certified by averaging emission levels across engine families and by using emission credits

[9] U.S. EPA (June 29, 2004), *Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel*; Final Rule, 69 Federal Register 38958-39273, http://www.gpo.gov/fdsys/pkg/FR-2004-06-29/pdf/04-11293.pdf

generated from engines previously certified to emission levels that are lower than the applicable certification standard.[10] Taking into account regulatory flexibilities, Tier 4 final engines are not being phased into production to meet the deadlines previously mentioned because engine manufacturers are using ABT credits to meet their emission standards. Also, OEMs are participating in TPEM which allows them to delay introduction of Tier 4 final engines. In addition, engines manufactured specifically for agricultural purposes account for a small percentage of the overall off-road engine population, especially in California as compared to the rest of the country. Therefore, while the Tier 4 final standards will become effective between 2013 and 2015, staff estimates a more reasonable expectation of the availability of Tier 4 final technologies for all power categories in mobile agricultural equipment will be in the 2020-timeframe.

[10] U.S. EPA (October 2008), *Progress Report Vehicle and Engine Compliance Activities*, EPA-420-R-08-11, pages 37-43, http://www.epa.gov/otaq/about/420r10022.pdf

II. STATEMENT OF REASONS

A. Description of Problem Proposal is Intended to Address

The CAA requires states to prepare and submit SIPs to U.S. EPA that demonstrate how each NAAQS will be met by the applicable deadline. SIPs must be reviewed and approved by U.S. EPA. The San Joaquin Valley is classified as extreme nonattainment for the 1997 ozone NAAQS, with an attainment deadline of 2023. The San Joaquin Valley is also classified as extreme nonattainment for the more stringent 2008 ozone NAAQS, with a deadline of 2032. Given the severity of the ozone air quality problem in the San Joaquin Valley, emissions from mobile agricultural equipment must be significantly reduced through a combination of regulations and incentive programs.

U.S. EPA's SIP approval process requires states to demonstrate that emissions reductions are documented and well quantified. This regulation provides an administrative mechanism to ensure that the emission reductions that are being achieved through incentive programs are approved by U.S. EPA. In 2010, U.S. EPA signed a Statement of Principles to work with ARB on a mechanism to provide SIP credit for investments being made in the San Joaquin Valley to clean up mobile agricultural equipment. SJVAPCD and U.S. Department of Agriculture are also signatories. This regulation will be submitted to U.S. EPA to implement the Statement of Principles, and to provide an enforceable process for determining the eligibility of emission reductions from mobile agricultural equipment incentive programs for SIP credit. U.S. EPA approval of the regulation as part of the California SIP will provide assurance that SIP credit can be taken for mobile agricultural equipment emission reductions used to demonstrate attainment of NAAQSs.

B. Proposed Solution

The proposed regulation provides an administrative mechanism to ensure that incentive funded projects implemented by SJVAPCD using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. The proposed regulation requires that, to become eligible to receive SIP credit, mobile agricultural equipment incentive projects must be implemented using Carl Moyer Program Guidelines. Using Carl Moyer Program Guidelines ensures that projects and the resulting emission benefits are surplus, quantifiable, enforceable, and permanent. Consistent with the Carl Moyer Program Guidelines, SJVAPCD and other air districts will be required to ensure accountability by monitoring and reviewing the programs and projects; ensure that projects remain within the area and properly report actual usage; enforce projects if contract terms are not met; and maintain project records and make those records available for public review upon request.

This proposed regulation also allows an opt-in for any other air district in California that complies with the requirements of the proposed regulation.

C. Rationale Supporting the Proposed Solution

Adoption of this mechanism allows SJVAPCD and other air districts to be eligible to receive SIP credit for the emission reductions from mobile agricultural equipment projects required to attain the appropriate NAAQS achieved through voluntary incentive programs. These voluntary incentive programs encourage fleet owners to turn over mobile agricultural equipment to Tier 3 or cleaner mobile agricultural equipment to implement a 2007 ozone SIP measure, which set a goal of achieving 5 to 10 tons per day of NOx reductions by 2017. Providing an accounting mechanism that can be approved by U.S. EPA ensures that California's SIP obligations are quantified accurately. If SIP credit for incentive programs is not approved by U.S. EPA, California would need to adopt additional regulations at a significant cost to businesses in the State.

D. Benefits Anticipated from Regulatory Action, Including the Benefits or Goals Provided in the Authorizing Statute

The proposed regulation ensures that ARB will meet the 2007 commitment to bring to the Board by 2013 a measure for mobile agricultural equipment in the San Joaquin Valley. Staff estimate that the emission reductions that will be eligible for SIP credit as a result of the proposed regulation will help meet the 2007 SIP goal for NOx emission reductions of 5 to 10 tons per day by 2017 and will accelerate air quality progress. Meeting these goals contributes to improved public health and also provides public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

III. SUMMARY OF PROPOSED ACTION

Staff's proposed regulation, *State Implementation Plan Credit from Mobile Agricultural Equipment*, provides an administrative mechanism to ensure that incentive funded projects implemented using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. Other air districts that comply with the requirements of the proposed regulation can opt-in and become eligible to receive SIP credit for voluntary incentive program mobile agricultural equipment project emission reductions.

IV. ENVIRONMENTAL IMPACTS ANALYSIS

A. Introduction

This section provides an environmental analysis for the proposed regulation. Based on ARB's review, staff has determined that implementing the proposed *Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment* will not result in any potentially significant adverse impacts on the environment. This analysis provides the basis for reaching this conclusion. This section also discusses environmental benefits expected from implementing the proposed regulation.

B. Environmental Review Process

ARB is the lead agency for the proposed regulation and has prepared this environmental analysis pursuant to its regulatory program certified by the Secretary of the Natural Resources Agency (14 CCR 15251(d); 17 CCR 60005-60007). In accordance with Public Resources Code Section 21080.5 of the California Environmental Quality Act (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). ARB has prepared this environmental analysis to assess the potential for significant adverse and beneficial environmental impacts associated with the proposed regulation, as required by ARB's certified regulatory program (17 CCR 60005(b)). The resource areas from CEQA Guidelines Environmental Checklist were used as a framework for assessing the potential for significant impacts (17 CCR 60005(b)).

If comments received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in the Final Statement of Reasons (FSOR) prepared for the proposed regulation. The final decision-maker will approve the written responses to comments prior to taking final action on the proposed regulation (17 CCR 60007(a)). If the proposed regulation is adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection (17 CCR 60007(b)).

C. Prior Environmental Analysis

ARB staff is proposing this new proposed regulation for mobile agricultural equipment that focuses on voluntary actions from the agricultural industry to reduce emissions through participation in incentive funding programs in order to accelerate the use of the cleanest available technologies in the San Joaquin Valley. This proposed regulation follows a Statement of Principles agreement reached amongst SJVAPCD, ARB, NRCS, and U.S. EPA, and with input from the agriculture industry, that would allow for a mechanism to be developed to provide SIP credit for investments being made by the agriculture industry to clean up mobile agriculture equipment. Because this proposed regulation is new, there were no prior

compliance responses required and no prior environmental analyses conducted relating to this proposed regulation.

D. Proposed Regulation

i. Description

The proposed regulation includes the provisions described in Section VII of this Staff Report. This proposed regulation would provide an administrative mechanism to ensure that mobile agricultural equipment incentive funded projects implemented using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. Other air districts that opt-in must also follow the requirements of this proposed regulation.

ii. Methods of Compliance

With the proposed regulation, ARB is providing SJVAPCD and other air districts with an administrative mechanism to ensure that mobile agricultural equipment incentive funded projects implemented using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. Because these administration requirements are already in use by SJVAPCD and other air districts, they do not go above and beyond or add to the standard administrative activities that air districts perform regularly.

E. Environmental Impacts

i. Beneficial Impacts

The proposed regulation provides an administrative mechanism to ensure that mobile agricultural equipment incentive funded projects implemented using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. The mechanism itself does not generate additional emissions reductions, but rather it encourages the funding of future emissions reductions through incentive programs and the voluntary participation of the agricultural industry. Early actions to voluntarily replace older, dirtier mobile agricultural equipment with newer, cleaner equipment using newer, cleaner technologies provide air quality and public health benefits.

The amount of emission reductions generated is dependent upon on the amount of incentive funds available, equipment characteristics such as age and annual usage, and the availability of cleaner technologies. In addition, the Carl Moyer Program Guidelines provides the methodology used to determine a project's emission reductions, cost-effectiveness, and the maximum grant amount that can be awarded.

ii. Resource Areas with No Impacts

Based on ARB's review of the proposed regulation, staff concludes that the proposed regulation is administrative in nature and does not result in any significant or potentially significant adverse impacts on the environment because compliance with the proposed regulation does not result in any physical change to the existing environment. The proposed regulation merely provides an administrative mechanism that does not require or result in any new development or require modifications to buildings or other structures, affect operations at existing facilities, or cause any new land use designation. The proposed regulation is therefore not expected to result in any adverse impacts that result from development including aesthetics, air quality, agricultural and forestry resources, biological resources, cultural resources, geology and soils, greenhouse gases, land use planning, mineral resources, population and housing, public services, recreation, or traffic and transportation.

Additionally, because compliance with the proposed regulation is voluntary and administrative in nature, the proposed regulation does not involve any activity that involves or affects hazardous materials, hydrology and water quality, noise, or recreation because it is an optional mechanism for obtaining SIP credit and does not mandate any action that affects these resources.

Although not required, the proposed regulation will likely encourage SJVAPCD and other air districts to continue to provide funding for the programs, and the agricultural industry to continue to voluntarily replace their older, dirtier equipment with newer, cleaner equipment through these programs. The proposed regulation mandates that, to be eligible to receive SIP credit, SJVAPCD and other air districts must adhere to the Carl Moyer Program Guidelines for mobile agricultural equipment projects to ensure that the emission reductions they produce are surplus, quantifiable, enforceable, and permanent. Other California air districts can opt-in if they comply with the requirements of this proposed regulation.

No discussion of alternatives or mitigation measures is necessary because no significant adverse environmental impacts were identified.

V. ENVIRONMENTAL JUSTICE

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. ARB is committed to making environmental justice an integral part of its activities. The Board approved its Environmental Justice Policies and Actions (Policies) on December 13, 2001, to establish a framework for incorporating environmental justice into ARB's programs consistent with the directives of State law (CARB 2001). These policies apply to all communities in California, but recognize that environmental justice issues have been raised more in the context of low-income and minority communities. The proposed regulation has no impact on State or other air district's Environmental Justice efforts.

VI. ECONOMIC IMPACT ANALYSIS/ASSESSMENT PREPARED PURSUANT TO GOVERNMENT CODE SEC. 11346.3(b)

A. Potential Cost Impacts of the Proposed Regulation

This proposed regulation does not affect or otherwise alter the economic benefit that businesses have received or will continue to receive from their participation in voluntary incentive programs for mobile agricultural equipment. The proposed regulation causes no additional work load or cost increases for either SJVAPCD or ARB, because ARB and SJVAPCD are already implementing and plan to continue to implement these programs. Furthermore, the Carl Moyer Program provides funding for administration of the program to ARB and participating air districts. Other air districts that opt-in to this proposed regulation may or may not already implement voluntary incentive program mobile agricultural equipment projects, but the proposed regulation imposes no extra work load or cost increases.

B. Major Regulations

HSC Section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to a proposed measure before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding $10 million. Staff estimates the cost of the proposed regulation to California is no cost.

C. Reasonable Alternatives to the Proposed Regulation and the Agency's Reason for Rejecting those Alternatives

Staff considered two alternatives to the proposed regulation. One alternative considered was "No Regulation"; that is, refrain from establishing a mechanism for mobile agricultural equipment voluntary incentive programs and projects to demonstrate emission reductions that can be eligible to receive SIP credit. Staff rejected this proposal because, as discussed in Section II, the administrative mechanism proposed is necessary for these mobile agricultural equipment voluntary incentive programs and projects to be eligible to receive SIP credit for the emission reductions that they are achieving and will continue to achieve, as well as the emission reductions to be achieved by new projects in the future. Under the "No Regulation" alternative, additional regulations would be needed to achieve the emission reductions equivalent to those achieved by the incentive programs.

The second alternative considered by staff was to accelerate development of a regulation to require the mobile agricultural equipment fleet in the San Joaquin Valley to turn over to the cleanest technologies by a set compliance schedule. Such a compliance schedule would be designed to accomplish fleet turnover at a faster rate than would otherwise occur through natural attrition in order to achieve emission reductions that meet SIP attainment goals.

Staff rejected this alternative for several reasons. First, staff estimates that the mobile agricultural equipment turnover from agriculture industry participation in voluntary incentive programs in the San Joaquin Valley that has been occurring and will continue to occur is sufficient to meet the 2007 emission reduction goal of 5 to 10 tons per day of NOx reductions by 2017. Therefore, the immediate regulatory need is to ensure a mechanism for achieving SIP credit for these emission reductions.

Second, a new ozone SIP process must be developed by 2016 to meet a more stringent 2008 federal 8-hour ozone standard, which identify additional reductions needed from mobile agricultural equipment with attainment required in 2032. More time is needed to develop a regulation proposal to address emissions from mobile agricultural equipment after 2017. As discussed in Section I.F., however, a near-term compliance schedule is not practical to consider at this time because the deployment of cleanest engine technologies (Tier 4 final) are not expected to be widely available in the agricultural sector until 2020.

Third, because Tier 4 final technologies in mobile agricultural equipment are not widely available now, requiring turnover prior to 2017 would result in a mobile agricultural equipment inventory that would not meet the needs for attainment in 2032. This would create a requirement for a second turnover of the fleet to Tier 4 final technologies when that equipment becomes available. Requiring the agriculture industry to turnover equipment twice will impose significant increased costs and is not necessary at this time because the voluntary incentive program agricultural equipment projects are meeting the 2007 SIP emission reduction goal.

Finally, to address the new 2008 federal standards and the additional post-2017 reduction needs, the process for a separate mobile agricultural equipment regulation has been started and scheduled for completion in 2015. This subsequent process will address both the remaining emission reduction needs for attainment in 2023 as well as provide additional reductions needed for the attainment in 2032.

D. Significant Adverse Economic Impact Directly Affecting Business-Evidence

This proposed regulation provides an administrative mechanism to ensure that incentive funded mobile agricultural projects implemented using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. The mechanism requires SJVAPCD and other air districts to use Carl Moyer Program Guidelines to implement the programs to ensure that emission reductions are surplus, quantifiable, enforceable, and permanent, and meet U.S. EPA guidance for SIP creditability of incentive funded projects. These programs, projects, and emission reductions, are occurring and will continue to occur, regardless of this proposed regulation. As such, this proposed regulation has no adverse economic impacts that directly affect business, including small businesses, and the Board has not identified any impacts or alternatives that would lessen any impacts on small

businesses. Even though other air districts may opt-in to this proposed regulation, the administrative mechanism similarly has no significant adverse economic impacts that directly affect business in those areas.

No alternatives considered by the Board would be more effective in carrying out the purpose for which the proposed regulation is proposed or would be as effective as or less cumbersome to affected private persons than the proposed regulation.

E. Justification for Adoption Regulations Different from Federal Regulations Contained in the Code of Federal Regulations

This proposed regulation does not differ from any federal regulations contained in the Code of Federal Regulations and therefore does not warrant justification for being different.

VII. SUMMARY AND RATIONALE FOR EACH REGULATORY PROVISION

This chapter describes the major provisions of the proposed regulation, including:

- Purpose
- Applicability
- Definitions
- Air District Requirements
- Incentive Program Guidelines
- Recordkeeping Requirements
- Project Monitoring Review Provisions
- Opt-in Provisions
- ARB Requirements

A discussion of the proposal's main elements and their rationale is provided below. The proposed regulatory text to adopt new article 4.1, section 2428, title 13, California Code of Regulations is contained in Appendix A.

A. Summary of Subsection 2428(a) Purpose

Subsection (a) of the proposed regulation provides an administrative mechanism to ensure that incentive funded mobile agricultural projects implemented by SJVAPCD using Carl Moyer Program Guidelines result in emission reductions that are eligible for SIP credit. While this proposed regulation establishes SIP eligibility, the emission reductions are quantified and granted credit to the SIP through a SIP amendment. Other air districts may opt-in to be eligible to receive SIP credit for emission reductions from voluntary incentive program mobile agricultural equipment projects if they notify the Executive Officer and follow the proposed requirements.

B. Rationale for Subsection 2428(a) Purpose

This subsection is needed for SJVAPCD and other air districts that opt-in to be eligible to receive SIP credit for off-road mobile agricultural equipment projects that are paid for following the Carl Moyer Program Guidelines. Furthermore, emission reductions achieved will assist in meeting the 2007 SIP goal of achieving 5 to 10 tons per day of NOx reductions and accelerate clean air quality progress.

C. Summary of Subsection 2428(b) Applicability

Subsection (b) of the proposed regulation applies to emission reductions achieved in the San Joaquin Valley from voluntary incentive program mobile agricultural equipment projects administered or implemented by ARB and SJVAPCD using Carl Moyer Program Guidelines. Other air districts may opt-in to the proposed regulation.

D. Rationale for Subsection 2428(b) Applicability

This subsection is needed to define that the proposed regulation applies to SJVAPCD and to other air districts that opt-in.

E. Summary of Subsection 2428(c) Definitions

Subsection (c) of the proposed regulation provides definitions of the terms used in the regulation.

F. Rationale for Subsection 2428(c) Definitions

This subsection is needed to provide clarity and support for the requirements presented within the proposed regulation. Many of the definitions are unique to this proposed regulation, but where possible the definitions come from existing regulations and state and federal guideline documents.

G. Summary of Subsection 2428(d) District Requirements

Subsection (d) of the proposed regulation clarifies the responsibility of SJVAPCD, and other districts that opt-in, to fulfill the requirements of this proposed regulation.

H. Rationale for Subsection 2428(d) District Requirements

This subsection is needed for emission reductions from incentive-funded mobile agricultural equipment projects to be eligible to receive SIP credit.

I. Summary of Subsection 2428(e) Incentive Program Guidelines

Subsection (e) of the proposed regulation requires that SJVAPCD, and other air districts that opt-in, must use Carl Moyer Program Guidelines to administer and implement voluntary incentive program mobile agricultural equipment projects to result in emission reductions that are eligible for SIP credit. Approved Carl Moyer Program Guidelines include the *2011 Carl Moyer Program Guidelines*, approved April 28, 2011; the *2008 Carl Moyer Program Guidelines*, approved March 27, 2008; and the *2005 Carl Moyer Program Guidelines*, approved November 17, 2005.

J. Rationale for Subsection 2428(e) Incentive Program Guidelines

This subsection is needed to provide the Carl Moyer Program Guidelines that SJVAPCD and other air districts that opt-in must use for programs that they seek to be eligible to receive SIP credit.

K. Summary of Subsection 2428(f) Recordkeeping Requirements

Subsection (f) of the proposed regulation requires that SJVAPCD and other air districts that opt-in must follow Carl Moyer Program Guidelines requirements to keep and maintain documents created or used for incentive-funded mobile agricultural

equipment projects that receive SIP credit. Such records must also be made available for public review, consistent with the California Public Records Act and other related requirements.

L. Rationale for Subsection 2428(f) Recordkeeping Requirements

This subsection is needed to ensure the records and documents are properly kept and maintained and to ensure that they are available for public review.

M. Summary of Subsection 2428(g) Project Monitoring Provisions

Subsection (g) of the proposed regulation requires that SJVAPCD and other air districts that opt-in must monitor the voluntary incentive program mobile agricultural equipment projects per Carl Moyer Program Guidelines requirements. These requirements verify and ensure that projects are surplus, quantifiable, enforceable, and permanent throughout the life of the contract. The proposed regulation also requires SJVAPCD and other air districts that opt-in to allow ARB to monitor the projects reported.

N. Rationale for Subsection 2428(g) Project Monitoring Provisions

This subsection is needed to ensure that expected emission reductions are achieved and are implemented in a manner consistent with Carl Moyer Program Guidelines, U.S. EPA Integrity Elements, and State law.

O. Summary of Subsection 2428(h) Opt-in Provisions

Subsection (h) of the proposed regulation allows air districts other than the SJVAPCD to opt-in to the proposed regulation. To opt-in, air districts must notify the ARB Executive Officer in writing and comply with the requirements of the proposed regulation to ensure that emission reductions from voluntary incentive program mobile agricultural equipment projects are eligible to receive SIP credit. In addition, the air district must adopt a local rule that meets the requirements of this proposed regulation and submit the local rule to U.S. EPA for approval.

P. Rationale for Subsection 2428(h) Opt-In Provisions

This subsection is needed to provide the steps necessary for air districts other than SJVAPCD to opt-in to the proposed regulation.

Q. Summary of Subsection 2428(i) ARB Requirements

Subsection (i) of the proposed regulation requires ARB to annually report to U.S. EPA by November 30 the participating air districts and the programs, projects, and project data they report to ARB per Carl Moyer Program Guidelines.

R. Rationale for Subsection 2428(i) ARB Requirements

This subsection is needed to provide the requirements and date for ARB to report to U.S. EPA the districts, programs, projects, and project data subject to the regulation.

VIII. PUBLIC PROCESS FOR DEVELOPMENT OF PROPOSED ACTION (PRE-REGULATORY INFORMATION)

This section describes the public process conducted by ARB during the development of the proposed regulation. ARB conducted three sets of public workshops to present proposals and to solicit public input. All of the Sacramento workshops were webcast to increase participation.

The first set of public workshops was held on September 6, 2012, September 18, 2012, and October 4, 2012, in Fresno, Sacramento and Redding, respectively. These workshops were kick-off workshops on the overall statewide off-road mobile agricultural equipment regulatory strategy. The Fresno workshop was also video telecast to Modesto and Bakersfield in order to reach more stakeholders. At these workshops, staff provided background information on the need for emission reductions from mobile agricultural equipment, an update on the development of the emissions inventories for mobile agricultural equipment, the data sources that were currently being utilized, the role of the economic analysis, and the next steps of the regulatory process.

The second set of public workshops was held on March 14, 2013 and March 15, 2013, in Fresno and Sacramento, respectively. The Fresno workshop was also video telecast to Modesto and Bakersfield. At these workshops, staff provided a proposal for a two-step approach for the regulatory strategy for mobile agricultural equipment, draft results from the *In-Use Mobile Agricultural Equipment Regulation Survey,*[11] the proposed regulation *State Implementation Plan Credit from Mobile Agricultural Equipment*, and the timeline for the regulatory development process.

The third public workshop was held on July 9, 2013 in Fresno with video telecast to Modesto and Bakersfield, and was webcast via the internet. At this workshop, staff presented the draft regulatory language for the proposed regulation for *State Implementation Plan Credit from Mobile Agricultural Equipment.*

Notices of the workshops were sent via the electronic In-Use Mobile and Stationary Diesel Agricultural Engines list serve and the general Mobile Source Mailings list serve. ARB also posted notice of the workshops and the workshop materials on its In-Use Off-Road Mobile Agricultural Equipment Regulation webpage.[12]

In addition to the public workshops, ARB staff worked extensively with the agricultural industry over the past few years to establish a better understanding of mobile agricultural equipment in California, their operating characteristics, and the impacts from equipment on emissions statewide and regionally. During the past year, ARB regulatory, inventory, and economic staff have had numerous meetings with farmers, custom operators, first processors, equipment and engine manufacturers, and industry organizations throughout California. ARB staff toured grower's fields, dairies,

[11] http://www.arb.ca.gov/ag/agtractor/agsurvey.htm
[12] http://www.arb.ca.gov/ag/agtractor/agtractor.htm

manufacturing plants, packing facilities, and feed lots. The tours covered a wide array of commodities, including: nuts, fruit (avocado, peaches, pomegranate, grapes, etc.), cotton, hay, rice, vegetables (potatoes, carrots, onions, etc.).

Staff also met with the California Farm Bureau and local Farm Bureaus throughout the state often attending their monthly meetings. For the past two years, staff attended the world's largest annual agricultural exposition, the World Ag Expo in Tulare. In the second year, ARB staff provided materials in an outreach booth in order to address stakeholders concern and receive their input. In addition to meeting with industry stakeholders, staff also held meetings with U.S. EPA, SJVAPCD and various environmental and health advocacy organizations. This resulted in valuable input and feedback that ultimately helped guide the direction of the proposed regulation for mobile agricultural equipment.

For additional information on public comments received during ARB's process to develop this proposed action see Appendix D.

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Appendix A

Proposed Regulation for

State Implementation Plan Credit from Mobile Agricultural Equipment

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Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment

Adopt new article 4.1, section 2428, title 13, California Code of Regulations to read as follows:

NOTE: The following text is all new text to be added to the California Code of Regulations.

§ 2428 Procedure for State Implementation Plan Credit from Mobile Agricultural Equipment.

(a) Purpose.

The purpose of this regulation is to provide an administrative mechanism for the State of California to receive credit towards the State Implementation Plan (SIP) requirements for emission reductions achieved in the San Joaquin Valley Air Pollution Control District from incentive-funded mobile agricultural equipment projects that are implemented using the Carl Moyer Program guidelines. This regulation will complement San Joaquin Valley Air Pollution Control District's Rule 9610, adopted by their governing board on June 20, 2013, which provides an administrative mechanism for the San Joaquin Valley Air Pollution Control District to receive credit toward SIP requirements for emissions reductions achieved in the San Joaquin Valley through incentive programs administered by the district, the U.S. Department of Agriculture Natural Resources Conservation Service, or the Air Resources Board (ARB). The two rules together ensure that emission reductions achieved through incentive programs in the San Joaquin Valley are eligible to become credited to SIP when quantified and included in a SIP amendment adopted by ARB and approved by United States Environmental Protection Agency (U.S. EPA) in accordance with the requirements of the federal Clean Air Act (CAA).

Other California Air Pollution Control Districts or Air Quality Management Districts (District) may to opt-in if the District governing board notifies the Executive Officer of the intent to participate, adopts a local rule that complies with the requirements of this regulation, and submits the local rule to ARB for approval. Upon approval, ARB will submit the local rule to U.S. EPA. Upon approval of the local rule by ARB and U.S. EPA, emission reductions that are determined to be eligible for SIP credit under this proposed regulation become credited to the SIP when quantified and included in a SIP amendment adopted by ARB and approved by U.S. EPA in accordance with the requirements of the CAA.

(b) Applicability.

This proposed regulation applies to emission reductions achieved from voluntary incentive-funded mobile agricultural equipment projects implemented using incentive program guidelines and administered or implemented by ARB or the District.

(c) Definitions.

(1) ***"Agricultural operations"*** means (1) the growing or harvesting of crops from soil (including forest operations) and the raising of plants at wholesale nurseries (but not retail nurseries), or the raising of fowl or animals for the primary

purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution, or (2) agricultural crop preparation services such as packinghouses, cotton gins, nut hullers and processors, dehydrators, and feed and grain mills. Agricultural crop preparation services include only the first processing after harvest, not subsequent processing, canning, or other similar activities. For forest operations, agricultural crop preparation services include milling, peeling, producing particleboard and medium density fiberboard, and producing woody landscape materials.

(2) ***"Air Pollution Control Officer (APCO)"*** means the District Air Pollution Control Officer, Executive Director, Executive Officer or designee.

(3) ***"Air Resources Board (ARB or CARB)"*** means the California State Air Resources Board as established by Health and Safety Code section 39510.

(4) ***"Carl Moyer Program"*** means the Carl Moyer Memorial Air Quality Standards Attainment Program, as defined by California Health and Safety Code Sections 44275– 44299.2.

(5) ***"Clean Air Act (CAA)"*** means the Clean Air Act, United States Code, Title 42, Chapter 85.

(6) ***"Contract"*** means a legally binding document including, but not limited to, contracts, grants, vouchers, rebates, loans, and loan guarantees signed by ARB or a District and the funding recipient to fund an incentive program project for the purpose of reducing emissions. Contracts include provisions for ensuring that the emission reductions occur, including, but not limited to, actions that the funding recipient must take to achieve the emission reductions for the project, deadlines, inspection and monitoring requirements, non-performance penalties, and contract term.

(7) ***"District"*** *means a local air pollution control district or air quality management district.*

(8) ***"Enforceable"*** means emission reductions are enforceable if the incentive program guidelines include provisions for ensuring the following:

(A) The emission reductions are independently and practicably verifiable through reporting, inspections, monitoring, or other mechanisms;
(B) Incentive program violations are defined through legally binding contracts, including identifying the party or parties responsible for ensuring that emission reductions are achieved;
(C) Funding recipients are obligated to provide all records needed to demonstrate that emission reductions are achieved; and
(D) The District provides public access to all emissions-related information for reductions claimed.

(9) ***"Executive Officer"*** means ARB Executive Officer.

(10) ***"Funding recipient"*** means a person, business, association, public agency, or other entity that enters into a contract with ARB or a District to reduce emissions under an incentive program.

(11) ***"Incentive program"*** means a program that reduces emissions by promoting the adoption of lower emitting mobile agricultural equipment through the distribution of funds to a funding recipient who chooses to voluntarily participate in the program.

(12) ***"Incentive program guidelines"*** means administrative procedures, emission reductions quantification methodologies, eligibility criteria, cost-effectiveness criteria, reporting practices, and other procedures and methodologies used to implement incentive programs, as described in Section (e).

(13) ***"Inspection"*** means a physical examination by an APCO of mobile agricultural equipment under contract as part of an incentive program.

(14) ***"Mobile agricultural equipment"*** means diesel-fueled, self-propelled, off-road equipment or vehicles with greater than 25 horsepower that are used in agricultural operations. For the purposes of this regulation, an equipment or vehicle that is used by its owner for both agricultural and nonagricultural operations is considered to be an equipment or vehicle engaged in agricultural operations only if over half of its annual operating hours are for agricultural operations.

(15) ***"Operating hours"*** means hours of mobile agricultural equipment use.

(16) ***"Permanent"*** means actions are taken to physically destroy or disable forever the older, dirtier mobile agricultural equipment to ensure the reduction of emissions for the duration of the project life.

(17) ***"Project"*** means actions taken to reduce emissions through incentive programs, as contracted between the funding recipient and ARB or a District. Such actions include, but are not limited to, replacements, retrofits, or repowers for one or more pieces of mobile agricultural equipment.

(18) ***"Project life"*** means the period of time over which an incentive program project achieves emission reductions that are surplus, quantifiable, enforceable, and permanent. Project life must not exceed the useful life of mobile agricultural equipment funded through incentive programs and may vary across incentive programs and project types.

(19) ***"Project type"*** means the type of mobile agricultural equipment funded through incentive programs.

(20) ***"Quantifiable"*** means emission reductions can be reliably determined through the use of well-established, publicly available emission factors and calculation methodologies, as outlined in applicable incentive program guidelines.

(21) ***"San Joaquin Valley Air Pollution Control District"*** means the regional governing authority that has primary responsibility for air quality management in eight counties including the entire counties of Fresno, Kings, Madera, Merced, San Joaquin, Stanislaus, Tulare, and the western portion of Kern County.

(22) ***"SIP attainment demonstration"*** means the technical control measures, analyses, and emission reduction commitments that show how a nonattainment area will meet a National Ambient Air Quality Standard by the applicable deadline.

(23) ***"State Implementation Plan (SIP)"*** means a plan which provides for implementation, maintenance, and enforcement of National Ambient Air Quality Standards promulgated by U.S. EPA.

(24) ***"Surplus"*** means emission reductions that are not otherwise required by any federal, state, or local regulation, or other legal mandate, and are in excess of the baseline emission inventory, attainment year, and progress milestone year forecasts that include adopted regulations.

(25) ***"U.S. EPA"*** means United States Environmental Protection Agency.

(26) ***"Western Portion of Kern County"*** means that portion of Kern County which lies west and north of a line described as follows: beginning at the Kern-Los Angeles County boundary and running north and east along the northwest boundary of the Rancho La Libre Land Grant to the point of intersection with the range line common to R. 16 W. and R. 17 W., San Bernardino Base and Meridian; north along the range line to the point of intersection with the Rancho El Tejon Land Grant boundary; then southeast, northeast, and northwest along the boundary of the Rancho El Tejon Land Grant to the northwest corner of S. 3, T. 11 N., R. 17 W.; then west 1.2 miles; then north to the Rancho El Tejon Land Grant boundary; then northwest along the Rancho El Tejon line to the southeast corner of S. 34, T. 32 S., R. 30 E., Mount Diablo Base and Meridian; then north to the northwest corner of S. 35, T. 31 S., R. 30 E.; then northeast along the boundary of the Rancho El Tejon Land Grant to the southwest corner of S. 18, T. 31 S., R. 31 E.; then east to the southeast corner of S. 13, T. 31 S., R. 31 E.; then north along the range line common to R. 31 E. and R. 32 E., Mount Diablo Base and Meridian, to the northwest corner of S. 6, T. 29 S., R. 32 E.; then east to the southwest corner of S. 31, T. 28 S., R. 32 E.; then north along the range line common to R. 31 E. and R. 32 E. to the northwest corner of S. 6, T. 28 S., R. 32 E., then west to the southeast corner of S. 36, T. 27 S., R. 31 E., then north along the range line common to R. 31 E. and R. 32 E. to the Kern-Tulare County boundary.

(d) District Requirements.

The District must fulfill the requirements of Sections (e) through (g) for emission reductions achieved from incentive-funded mobile agricultural equipment projects implemented using incentive program guidelines to be considered for SIP credit.

(e) Incentive Program Guidelines.

The District must use Carl Moyer Program guidelines to fund mobile agricultural equipment projects that result in emission reductions that are surplus, quantifiable, enforceable, and permanent as defined in this regulation. (2011 Carl Moyer Program Guidelines, approved April 28, 2011; 2008 Carl Moyer Program Guidelines, approved March 27, 2008; and 2005 Carl Moyer Program Guidelines, approved November 17, 2005, all as incorporated by reference herein.)

(f) Recordkeeping Requirements.

All documents created and used for incentive-funded mobile agricultural equipment projects must be kept by an air district and maintained as required by the incentive

program guidelines. Consistent with the California Public Records Act and other related requirements, such records shall be made available for public review.

(g) Project Monitoring Provisions.

(1) Each calendar year, a District must monitor incentive-funded mobile agricultural equipment projects implemented using incentive program guidelines to ensure projects are surplus, quantifiable, enforceable, and permanent throughout the life of the contract.

(2) The District must allow ARB to conduct program reviews of incentive-funded mobile agricultural equipment projects that are implemented and used for SIP credit. ARB will conduct these reviews as specified in the 2011 Carl Moyer Program Guidelines, Chapter 3, Section V., approved April 28, 2011; 2008 Carl Moyer Program Guidelines, Part III of IV, Part F, approved March 27, 2008; and 2005 Carl Moyer Program Guidelines, Part I of IV, Chapter 2, approved November 17, 2005, incorporated by reference herein.

(h) Opt-in Provisions.

Emission reductions achieved from incentive-funded mobile agricultural equipment projects in Districts other than the San Joaquin Valley Air Pollution Control District that are implemented using incentive program guidelines are eligible to be considered to receive credit toward SIP requirements.

(1) Districts must notify the Executive Officer in writing of their intention to comply with the requirements of this proposed regulation, and

(2) Districts must adopt a local rule that complies with all requirements of this proposed regulation, and

(3) Districts must submit their local rule to ARB for approval.

(i) ARB Requirements.

ARB must annually report to U.S. EPA by November 30 the participating Districts, programs, projects, and project data reported to ARB per Carl Moyer Program Guidelines.

Note: Authority cited: Sections 39001, 39003, 39500, 39515, 39516, 39600, 39601, 39602, 39602.5, 39659, 43000, 43000.5 and 44291, Health and Safety Code. Reference: Sections 39002, 39515, 39516, 39600, 39601, 39602, 39602.5, 39650, 39656, 39657, 39658, 39659, 43000, 43000.5 and 43018, Health and Safety Code.

Appendix B

Statement of Principles – December 2010

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Statement of Principles Regarding the Approach to State Implementation Plan Creditability of Agricultural Equipment Replacement Incentive Programs Implemented by the USDA Natural Resources Conservation Service and the San Joaquin Valley Air Pollution Control District

December 2010

Statement of Principles
December 2010

Introduction

The U.S. Department of Agriculture Natural Resources Conservation Service (NRCS) is implementing an Environmental Quality Incentive Program in California to help achieve federal air quality standards and meet emission reduction goals of the State Implementation Plans (SIP) for the San Joaquin Valley. This federal incentive program complements existing State and local incentive programs in California. The NRCS program is modeled after California's Carl Moyer Incentive Program, which was developed as part of California's 1994 Ozone SIP approved by U.S. Environmental Protection Agency (U.S. EPA) in 1997. The San Joaquin Valley Air Pollution Control District (District) is also implementing a program to achieve SIP creditable reductions through the early introduction of cleaner agricultural equipment. Both agencies are applying strict criteria to ensure the emission reductions achieved are surplus, quantifiable, enforceable, and permanent.

Relationship to San Joaquin Valley 2007 Ozone SIP

The San Joaquin Valley faces significant challenges in achieving attainment with the U.S EPA's ambient air quality standards. The District has many of the nation's toughest air pollution rules already in place, and many new regulations are in progress under the District's most recent attainment plans, such as the *2007 Ozone Plan*. However, regulations alone will not bring the Valley into attainment of federal air quality standards.

When the Air Resources Board (ARB) approved the District's *2007 Ozone Plan* on June 14, 2007, ARB committed to investigate additional control measures before transmitting the plan to the U.S. EPA. When ARB adopted the 2007 State Strategy on September 27, 2007, ARB committed to reducing emissions from agricultural equipment in the Valley beginning in 2014, with five to ten tons per day of NOx reductions in the Valley by 2017. This measure would accelerate fleet turnover to equipment with engines meeting cleaner new engine NOx standards as quickly as possible. ARB committed to meeting this reduction target through regulatory or voluntary incentive measures, stating that it would be *"supporting efforts to secure federal funds and other mechanisms to achieve near-term reductions that can be credited to the SIP."*

This statement of principles establishes a general framework for ensuring that reductions in air emissions resulting from voluntary incentives to replace off-road agricultural equipment receive credit in State Implementation Plans (SIPs). Given the heavy investment from the public sector and agricultural community in replacing equipment under these voluntary incentives, establishing a general framework to receive SIP credit for these emissions reductions is critical for ensuring the continued success of these programs. These voluntary incentives are administered by the District and NRCS.

Statement of Principles

1. The District, NRCS, ARB, and U.S. EPA will work collaboratively to develop a mechanism to provide SIP credit for emissions reductions from the federal, state, and local incentive programs that meet the criteria of ensuring the reductions are surplus, quantifiable, enforceable, and permanent.

2. The District and NRCS will each submit annual reports of the prior year's completed projects and associated emission reductions to U.S. EPA and ARB.

3. U.S. EPA will expeditiously review the submitted annual report. If EPA determines that the emissions reductions are consistent with the mechanism and criteria in Principle 1, EPA would credit the emission reductions toward the SIP.

4. The District and NRCS will ensure ongoing accountability by maintaining databases of project data, application information, funded-project data, and emissions reductions; and record retention of application forms, inspection documentation, destruction verification, and other project-relevant documentation.

Signed for U.S. EPA By,

for Deborah Jordan
Director, Air Division, Region IX

Date: 12-15-10

Signed for SJVUAPCD By,

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Date: 12/15/10

Signed for USDA, NRCS By,

for Lincoln E. Burton
State Conservationist for California

Date: 12-16-10

Signed for ARB By,

James Goldstene
Executive Officer

Date: 12/15/10

Appendix C

San Joaquin Valley Air Pollution Control District Rule 9610 – State Implementation Plan Credit for Emission Reductions Generated Through Incentive Programs – Adopted June 20, 2013

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RULE 9610 STATE IMPLEMENTATION PLAN CREDIT FOR EMISSION REDUCTIONS GENERATED THROUGH INCENTIVE PROGRAMS (Adopted June 20, 2013)

1.0 Purpose

The purpose of this rule is to provide an administrative mechanism for the District to receive credit towards State Implementation Plan requirements for emission reductions achieved in the San Joaquin Valley Air Basin through incentive programs administered by the District, NRCS, or ARB.

2.0 Definitions

2.1 APCO: the Air Pollution Control Officer of the San Joaquin Valley Unified Air Pollution Control District, or any person authorized to act on behalf of the APCO.

2.2 ARB: the California state Air Resources Board as established by California Health and Safety Code Section 39510, or any person authorized to act on its behalf.

2.3 Carl Moyer Program: the Carl Moyer Memorial Air Quality Standards Attainment Program; a State of California funded incentive program as defined by California Health and Safety Code Sections 44275– 44299.2.

2.4 Case-by-Case Determination: alternative procedures approved by ARB for specific projects, as authorized under the Carl Moyer Program Guidelines.

2.5 Contract: a legally binding agreement signed by the District, NRCS, or ARB and the Grantee to fund an incentive project for the purpose of reducing emissions. Contracts shall include provisions for ensuring that the emissions reductions occur, including, but not limited to, actions that the Grantee must take to achieve the emission reductions for the project, project specific deadlines, inspection and monitoring requirements, and non-performance remedies.

2.6 Cost Effectiveness: the amount of incentive funding expended per ton of emissions reduced, as defined by the applicable incentive program guidelines.

2.7 District: the San Joaquin Valley Unified Air Pollution Control District.

2.8 Enforceable: for purposes of this rule, emission reductions are enforceable if the incentive program includes provisions for ensuring the following:

2.8.1 The emission reductions are independently and practicably verifiable through inspections, monitoring, and/or other mechanisms;

2.8.2 Incentive program violations are defined through legally binding contracts, including identifying the party or parties responsible for ensuring that emission reductions are achieved;

2.8.3 Grantees are obligated to provide all records needed to demonstrate that emission reductions are achieved; and

2.8.4 The public has access to all emissions-related information for reductions claimed in the annual demonstration report, as outlined in Section 4.0.

2.9 EPA: the United States Environmental Protection Agency.

2.10 EQIP: Environmental Quality Incentives Program; a voluntary program administered by the NRCS that provides financial and technical assistance to agricultural producers to plan and implement conservation practices that address natural resource concerns, including the improvement of combustion systems from stationary agricultural irrigation pump engines and mobile agricultural equipment.

2.11 Funding Source: a source of funding used to implement incentive programs, including, but not limited to, federal, state, and local sources. Examples of funding sources include Carl Moyer Program funds and Proposition 1B – Goods Movement Emission Reduction Program funds.

2.12 Grantee: a person, business, association, public agency, or other entity that enters into a contract with the District, NRCS, or ARB to reduce emissions under an incentive program.

2.13 Implementation Date: for the purposes of this rule, the date which new or replacement equipment, vehicles, or practices funded through incentive programs are put into service.

2.14 Incentive Program: a program that reduces emissions by promoting the adoption of lower emitting equipment, vehicles, or practices through the distribution of financial incentives to a Grantee.

2.15 Incentive Program Guidelines: administrative procedures, quantification methodologies, eligibility criteria, cost effectiveness criteria, reporting practices, and/or other procedures and methodologies used to implement incentive programs, as identified in Section 3.0.

2.16 Inspection: for purposes of this rule, a physical inspection by the APCO of the equipment, vehicle, or practice under contract as part of an incentive project.

2.17 NRCS: the United States Department of Agriculture Natural Resources Conservation Service.

2.18 Permanent: for purposes of this rule, emission reductions are permanent if actions are taken to physically destroy or permanently disable existing or baseline equipment or vehicles, or to permanently amend practices to ensure the reduction of emissions for the duration of the project life.

2.19 Project: for purposes of this rule, actions taken to reduce emissions through incentive programs, as contracted between the Grantee and the District, NRCS, or ARB using incentive program guidelines at the time of contracting. Such actions include, but are not limited to, replacements, retrofits, new purchases, new practices, and repower.

2.20 Project Life: for purposes of this rule, the period of time over which an incentive program project achieves SIP-creditable emission reductions. Project life shall not exceed the useful life of equipment, vehicles, or practices funded through incentive programs, and may vary across incentive programs and project types.

2.21 Project Type: for purposes of the annual demonstration report required by this rule, the project type is identified as the type of equipment, vehicle, or practice, and the action taken.

2.22 Proposition 1B: the Goods Movement Emission Reduction Program; a State of California funded incentive program as codified in California Health and Safety Code Section 39625 et seq.

2.23 Quantifiable: for purposes of this rule, emission reductions are quantifiable if they can be reliably determined through the use of well-established, publicly available emission factors and calculation methodologies.

2.24 SIP: the State Implementation Plan; a plan which provides for implementation, maintenance, and enforcement of National Ambient Air Quality Standards promulgated by EPA.

2.25 SIP-Creditable Emission Reduction: for purposes of this rule, reductions of emissions achieved through incentive programs that are Surplus, Quantifiable, Enforceable, and Permanent, as those terms are defined in this rule.

2.26 SIP Shortfall: for purposes of this rule, an instance when a commitment made pursuant to Section 7.0 in an adopted SIP to achieve a certain amount of SIP-creditable emission reductions is not achieved.

2.27 Surplus: for purposes of this rule, emission reductions are surplus when they are not otherwise required by any federal, state, or local regulation, or other legal mandate, and are in excess of the baseline emission inventories underlying a SIP attainment demonstration.

2.28 Valley: the San Joaquin Valley Air Basin including Fresno, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare Counties, and the San Joaquin Valley Air Basin portion of Kern County.

3.0 Incentive Program Guidelines

3.1 The District shall quantify emission reductions under this rule in accordance with the following specific incentive program guidelines that provide for SIP-creditable emission reductions:

3.1.1 ARB Carl Moyer Program Guidelines for incentive projects funded by either the Carl Moyer Program or non Carl Moyer funding sources, for the following project types:

3.1.1.1 On-Road Heavy-Duty Vehicle

3.1.1.1.1 New Vehicle Purchase (Chapter 1, approved 11/17/2005; Chapter 3, approved 2008; or Chapter 4, approved 4/28/2011);

3.1.1.1.2 Repower (Chapter 1, approved 11/17/2005; Chapter 3, approved 2008; or Chapter 4, approved 4/28/2011); or

3.1.1.1.3 Retrofit (Chapter 1, approved 11/17/2005; Chapter 3, approved 2008; or Chapter 4, approved 4/28/2011).

3.1.1.2 On-Road Heavy-Duty Vehicles Fleet Modernization/Replacement (Chapter 2, approved 11/17/2005; Chapter 4, approved 3/27/2008; or Chapter 5, approved 4/28/2011).

3.1.1.3 Off-Road Compression-Ignition Equipment

3.1.1.3.1 Repower (Chapter 5, approved 11/17/2005; Chapter 5, approved 3/27/2008; or Chapter 7, approved 4/28/2011);

3.1.1.3.2 Replacement (Chapter 4, approved 3/27/2008: or Chapter 9, approved 4/28/2011): or

3.1.1.3.3 Retrofit (Chapter 5, approved 11/17/2005; Chapter 5, approved 3/27/2008: or Chapter 7, approved 4/28/2011).

3.1.1.4 Portable and Stationary Agricultural Sources

3.1.1.4.1 Repower (Chapter 10, approved 11/17/2005; Chapter 10, approved 3/27/2008: or Chapter 10, approved 4/28/2011):

3.1.1.4.2 New purchase of electric motor (Chapter 10, approved 11/17/2005; Chapter 10, approved 3/27/2008; or Chapter 10, approved 4/28/2011); or

3.1.1.4.3 Retrofit (Chapter 10, approved 11/17/2005; Chapter 10, approved 3/27/2008: or Chapter 10, approved 4/28/2011).

3.1.2 NRCS Conservation Practice Standard 372 - Combustion System Improvement (approved September 2010); Conservation Practice Standard 723 – Combustion System Air Emission Management (approved May 2009); NRCS General Manual, Title 450, Part 401 – Conservation Practice Standards (approved October 18, 2009): NRCS General Manual, Title 450, Part 407 – Documentation, Certification, and Spot Checking (approved October 17, 2009): Conservation Practice Standard 372 Specification (approved September 2010); NRCS Interim Conservation Practice Standard 723 – Combustion System Air Emission management (approved May 2009); NRCS Combustion System Improvement 372 Operation and Maintenance; and associated NRCS Program Combustion System Improvement of Mobile Engines Guidelines (December 2011; updated May 2012) for incentive projects funded by EQIP funds.

3.1.3 ARB Proposition 1B Goods Movement Emission Reduction Program Guidelines for Heavy-Duty Diesel Trucks repower, replacement, PM retrofit, or PM + NOx retrofit incentive projects funded by Proposition 1B funds or non-Proposition 1B funds. Applicable ARB Proposition 1B Goods Movement Emission Reduction Program Guidelines are the 2013 Proposition 1B: Goods Movement Emission Reduction Program Guidelines (Appendix A, approved 01/25/2013): the 2010 Proposition

1B: Goods Movement Emission Reduction Program Guidelines (Appendix A, approved 03/25/2010); and the 2008 Proposition 1B: Goods Movement Emission Reduction Program Guidelines (Appendices A or B, approved 02/28/2008).

3.2 Subject to sections 3.2.1 and 3.2.2 below, the District may quantify emission reductions under this rule in accordance with incentive program guidelines not specifically identified in Section 3.1, provided the District submits to EPA, pursuant to Section 7.0, a demonstration that each such guideline provides for SIP-creditable emission reductions. Incentive program guidelines subject to these procedures may include ARB Carl Moyer Program Guidelines, NRCS Combustion System Improvement Conservation Practice Standard 372 and associated NRCS Program Combustion System Improvement of Mobile Engines Guidelines, and ARB Proposition 1B Goods Movement Emission Reduction Program Guidelines.

3.2.1 Incentive program guidelines developed by the District to reduce emissions from mobile sources shall be developed in consultation with ARB.

3.2.2 Notwithstanding Sections 3.1 or Section 3.2, no case-by-case determination may be used to quantify emission reductions under this rule unless such determination is reviewed through a public process and submitted to EPA in accordance with Section 7.0.

3.3 The District shall develop and maintain a Manual of Procedures that includes all incentive program guidelines used to achieve SIP-creditable emission reductions from incentive programs, pursuant to Section 3.0. The Manual of Procedures shall:

3.3.1 Be made publically available on the District's website and maintained on an ongoing basis as incentive program guidelines are adopted; and

3.3.2 Include a description of how the incentive program guidelines ensure that incentive program emission reductions are SIP-creditable.

4.0 Annual Demonstration Report

The APCO shall annually prepare a report that demonstrates the quantity of SIP-creditable emission reductions. This report shall include the following elements, and shall be prepared and submitted to ARB and EPA through a public process in accordance with Section 5.0.

4.1 Description of incentive program guidelines used by the District, NRCS, or ARB to implement the incentive programs generating claimed SIP-creditable emission reductions, a description of how the guidelines ensure that the claimed emission

reductions are SIP-creditable, and a list of any guidelines that are being used for the first time under this rule.

4.2 SIP-creditable emission reductions generated through incentive programs, as implemented in the preceding year(s), summarized by pollutant, years that the emission reductions are occurring (project life), cost effectiveness, funding amount, incentive program guideline, and project type.

4.3 Adjustments to SIP-creditable emission reductions claimed in prior annual demonstration reports shall be reported in the annual demonstration report the year that the adjustments are made with a discussion explaining the cause for the adjustments. Adjustments to emission reductions claimed in prior annual demonstration reports may be the result of, but are not limited to, updated project information received during the course of project implementation or the adoption of new local, state, or federal requirements that might affect the surplus nature of emission reductions achieved by incentive programs.

4.4 Identification of SIP commitment(s) identified in District adopted SIP(s) (by year, pollutant, and magnitude), which the District has satisfied, in whole or in part, through SIP-creditable emission reductions. Such commitments include, but are not limited to, emission reduction commitments adopted to meet Clean Air Act requirements concerning the demonstration of attainment, Reasonable Further Progress, Rate of Progress, contingency measures, and long-term measures as defined by the federal Clean Air Act Section 182(e)(5) ("black box" reductions). The District shall identify and quantify SIP commitment shortfalls, if any, and remedies for addressing said shortfalls.

4.5 Project Information

Reported project information shall include the following information for incentive projects achieving SIP-creditable emission reductions, as applicable:

4.5.1 Unique project identification number, as established by the District, NRCS, or ARB;

4.5.2 Project location;

4.5.3 Project type;

4.5.4 Project life;

4.5.5 Implementation date of project;

4.5.6 Funding amount provided by District, NRCS, or ARB;

4.5.7 Incentive program guideline(s) used to implement the project, including revision date;

4.5.8 Quantified emission reductions per year, and aggregated over the project life, by pollutant; and

4.5.9 Description of both the baseline and the new equipment, vehicles, or practices, including the following for each, as applicable:

4.5.9.1 Make and model of equipment or vehicle;

4.5.9.2 Equipment or vehicle rating or horsepower;

4.5.9.3 Model year; and

4.5.9.4 Historical and projected annual usage.

4.5.10 Additional project details, as necessary to demonstrate the SIP-creditable emission reductions claimed in the annual demonstration report.

4.6 Project Monitoring and Enforcement

The annual demonstration report shall include a summary of monitoring and enforcement activities conducted during the reporting period for incentive projects for which SIP-creditable emission reductions are being claimed, as follows:

4.6.1 Identification of project audits, usage reports, inspections, and other project monitoring activities; and

4.6.2 List of actions taken to enforce emission reductions associated with contract requirements, including the following:

4.6.2.1 Identification of projects that do not satisfy contractual requirements; and

4.6.2.2 Identification of enforcement actions and remedies, including penalties, additional contractual requirements, or other actions.

4.7 Incentive Program Evaluation

The District shall perform a retrospective assessment of the performance of its incentive program to evaluate overall incentive program performance and develop recommendations for future enhancements to incentive program implementation.

This assessment shall include a summary of the public process to receive comments on the draft report, as required by Section 5.0.

5.0 Annual Demonstration Report Process

5.1 The APCO shall submit the annual demonstration report and information described in Section 4.0 to ARB and EPA no later than August 31 of each year.

5.2 The APCO shall release the draft annual demonstration report to the public and present it to the District Governing Board prior to submittal to ARB and EPA for concurrence.

5.3 Previously submitted annual demonstration reports shall be made available on the District's website.

6.0 Recordkeeping Requirements

6.1 All documents created and/or used in implementing the requirements of Section 4.0 shall be kept and maintained as required by the applicable incentive program guidelines. Consistent with the California Public Records Act and other related requirements, such records shall be made available for public review. Information regarding the process for the public review of such records shall be included in the annual demonstration report.

6.2 Records related to implementation of the NRCS Program Combustion System Improvement of Mobile Engines incentive program are prohibited from mandatory disclosure, pursuant to the Federal Food Security Act of 1985 (7 U.S.C. § 608d(2)).

7.0 Use of Projected Incentive Program Reductions in SIPs

Where the District intends to rely on projections of SIP-creditable emission reductions under this rule to satisfy a federal Clean Air Act SIP requirement (e.g., attainment, Reasonable Further Progress, Rate of Progress, contingency measures, or long-term measures as defined by the federal Clean Air Act Section 182(e)(5) ("black box" reductions)), the District shall identify specific amounts of SIP-creditable emission reductions for a particular year or years in the relevant SIP. Each SIP submission in which the District relies on such projections shall contain a demonstration that the applicable incentive program guideline(s) continues to provide for SIP-creditable emission reductions and shall contain an enforceable commitment that:

7.1 Identifies incentive program guidelines, as specified in Section 3.0, used to generate projected SIP-creditable emission reductions;

7.2 Identifies emission reductions not to exceed the amount projected to be achieved through the use of secured or reasonably anticipated incentive program funding and the estimated availability of emission reductions projects and willing participants, based on historical participation and estimates of remaining equipment;

7.3 Is specifically adopted by the District as a part of the SIP and accounted for in the annual demonstration report as SIP-creditable emission reductions are achieved through provisions of this rule; and

7.4 States that if either the District or EPA finds that there is a SIP shortfall for a particular year, the District will adopt and submit to EPA, by specified dates, substitute rules and measures that will achieve equivalent emission reductions as expeditiously as practicable and no later than any applicable implementation deadline in the Clean Air Act or EPA's implementing regulations.

Appendix D

Summary of Public Comments and ARB Responses

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I. Introduction

In 2012, California Air Resources Board (ARB) staff began the public regulatory development process for mobile agricultural equipment. A primary focus of this process was for staff to gain a thorough understanding of California's agricultural industry, its economic impacts on the State, and how the agricultural industry uses, maintains, and replaces mobile agricultural equipment. In addition, staff's efforts included soliciting public comments from stakeholders and other interested parties. Staff also created a dedicated webpage to provide public information of the background for the proposed regulation, timeline of events, notice of public workshops, documents, links to other relevant websites, staff contact information, and a list-serve signup to receive email notifications. ARB also held a series of public workshops to present information about the proposed regulation, inform stakeholders on the progress of the regulation development, and provide a forum for the public to communicate their ideas, comments, and questions regarding the proposed regulation.

A Final Statement of Reasons for Rulemaking (FSOR) will follow and update the Initial Statement of Reasons (ISOR) to which this document is an appendix. The FSOR will provide summaries of the written and oral comments received during the 45-Day and 15-Day Comment Periods and ARB's responses to those comments.

A. Workshops

The following is a list of public workshops held including the date of workshop, topic summary, and location.

1. Initial workshop series to notify the public and receive input on effectively achieving emission reductions from mobile agricultural equipment and include discussion of the emissions inventory, economic analysis, expected timeline, and public process for rule development.

   Date: September 6, 2012
   Location: San Joaquin Valley Air Pollution Control District offices: main meeting in Fresno, simulcast to Bakersfield and Modesto.

2. Repeat of initial public workshop with webcast.
   Date: September 18, 2012
   Location: Sacramento

3. Repeat of initial public workshop.
   Date: October 4, 2012
   Location: Redding

4. Second series of workshops held for public input on California's air quality goals and the need for emission reductions from mobile agricultural equipment. Topics discussed include: draft survey results from mobile

agricultural equipment, assessment of local, State, and federal financial incentive programs, the development of a mechanism to ensure local, State, and federal incentive program reductions are creditable to the State Implementation Plan (SIP), and the availability of cleaner technologies (tier 4 final) in mobile agricultural equipment.

Date: March 14, 2013
Location: San Joaquin Valley Air Pollution Control District offices: main meeting in Fresno, simulcast to Bakersfield and Modesto.

5. Repeat of second public workshop with webcast.
Date: March 15, 2013
Location: Sacramento

6. Third workshop held for public input on draft proposals for the regulation.
Date: July 9, 2013
Location: San Joaquin Valley Air Pollution Control District offices: main meeting in Fresno, simulcast to Bakersfield and Modesto. In addition, the workshop was webcast via the internet.

B. During this Rulemaking

Actions taken during this rulemaking include gathering data about the California agricultural industry and the mobile agricultural equipment used by the industry and understanding how the equipment contributes to air quality problems in California. Staff communicated with and listened to stakeholders about their views and concerns about these issues. Comments and questions were received from the public throughout this process, through conversation during tours of farms and ranches, received through email and by letters, and during public workshops.

II. Summary of Comments, Questions, and Agency Responses to the Proposal

The following is a summarization of the comments and questions received from stakeholders during the rulemaking process since March 2012.

A. Regarding Emission Reductions from Mobile Agricultural Equipment

Staff received a number of comments (listed below) regarding whether there exists a need for emission reductions from mobile agricultural equipment in all areas of California or just the San Joaquin Valley.

- Mobile agricultural equipment should only be regulated in areas of the state where they contribute to a significant air pollution problem.

- A mobile agricultural equipment regulation should apply to all regions of the State to avoid placing certain areas in a competitive disadvantage.
- The percentage that mobile agricultural equipment contributes to the air pollution problem in the San Joaquin Valley and in other areas of the State is very small.
- The mobile agricultural equipment fleet causes air pollution and should be regulated like other mobile sources in California.
- Growing crops produce air quality benefits that should be measured and could balance emissions from mobile agricultural equipment.

RESPONSE:
The *Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment* is designed to address the 2007 8-Hour Ozone SIP goal of achieving 5 to 10 tons per day emission reductions of nitrogen oxides (NOx) in the San Joaquin Valley by providing an administrative mechanism to be eligible to receive SIP credit. The 2007 SIP did not identify emission reduction goals for mobile agriculture equipment for areas other than the San Joaquin Valley. In the San Joaquin Valley, mobile agricultural equipment plays a significant role in the air quality challenges, accounting for over 13 percent of the total NOx emissions from mobile sources.[1]

The proposed regulation is an administrative mechanism that concerns programs, projects, and emission reductions that are already occurring and will continue to occur regardless of whether the proposed regulation is adopted. As such, the proposed regulation will not place the San Joaquin Valley in a competitive disadvantage with other areas of the State. The competitive position of other California air districts that opt-in to this proposed regulation will similarly not be affected.

A new 2016 ozone SIP process, based on more stringent 2008 federal standards for 8-hour ozone, will identify additional reductions needed from mobile agricultural equipment with attainment required in 2032. To address the new 2008 federal standards and the additional reduction needs that may result during the development of the new SIP, a second mobile agricultural equipment regulation process will include accelerated fleet turnover as one of the strategies to be considered. This subsequent process will address both the remaining emission reduction needs for attainment in 2023 as well as provide additional reductions needed for the attainment in 2032.

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[1] California Emissions Projection Analysis Model (CEPAM)
http://outapp.arb.ca.gov/cefs/norcal2012pm25sip/

B. Regarding Inventory of Mobile Agricultural Equipment

Staff received a number of questions and comments (listed below) regarding the inventory of mobile agricultural equipment in California and particularly in the San Joaquin Valley.

- What is the inventory of mobile agricultural equipment in California and other areas in the State?
- How did ARB develop the inventory?
- What is the inventory comprised of in terms of age, use, size, and other factors?
- What is the natural turnover of the fleet?
- Aren't the emission reductions that are being achieved through natural turnover of the mobile agricultural equipment fleet enough?
- How does ARB model what happens to the inventory if a regulation is enacted?
- How will this regulation affect the inventory?
- What happens if the inventory is significantly incorrect?
- How do the incentive program mobile agricultural equipment projects being done in the San Joaquin Valley affect the inventory?

RESPONSE:
An inventory is a representation of the emissions from mobile agricultural equipment in the State as a whole and within regions of the State. Information on equipment characteristics is combined with emissions measurements to produce an emissions inventory. In 2009, ARB, in conjunction with California State University Fresno and the agriculture industry, began a survey of how mobile agricultural equipment is used, maintained, and replaced. Mobile agricultural equipment is defined as diesel-fueled, self-propelled, off-road equipment or vehicles with greater than 25 horsepower that are used in agricultural operations. The results of the survey were presented during the March 14 and 15, 2013, workshops held for this regulation. The full presentation is available on the ARB website, http://www.arb.ca.gov/ag/agtractor/workshop/wspres03142013.pdf.

The results of the survey show a total of 151,900 pieces of mobile agricultural equipment operating in California, including 77 percent tractors, 10 percent harvesters, 6 percent loaders, and 7 percent "other." By sector, producers have the largest population of equipment in the State, representing about 71 percent of the total. Custom operators represent about 25 percent, and the remaining 4 percent are made up of rental, first processor, and logging operations.

Turnover in this context is defined as the normal process the fleet of mobile agricultural equipment undergoes as used equipment is replaced or scrapped and newer equipment is purchased. So called "natural" turnover is how this process occurs without regulatory requirements that result in more rapid turnover. Since 2008, natural turnover in the San Joaquin Valley has been enhanced by over 2,500 pieces of mobile agricultural equipment that have been replaced through the several voluntary incentive programs in the San Joaquin Valley. Staff estimates that these

and future projects resulting from continued funding will meet the SIP goal of NOx reductions of 5 to 10 tons per day by 2017. The proposed regulation will not affect natural turnover in the San Joaquin Valley, or other air districts that opt-in, because the incentive programs, projects, and emission reductions are occurring and will continue to occur regardless of this proposed regulation.

C. Regarding Turnover of Equipment to Cleaner Technology

Staff received a number of comments (listed below) regarding why the turnover of equipment to cleaner technology should or should not be required.

- The agriculture industry should be required to turn over the entire fleet to cleaner equipment now and to the cleanest equipment once it becomes available.
- What constitutes "cleaner technology" and "cleanest technology?"
- New technologies such as particulate filters and other emission reduction technologies are inappropriate for agriculture due to safety and cost issues.
- New technologies have higher operating temperatures that increase fire danger and insurance costs.
- New mobile agricultural equipment requires larger engine compartments that cause safety issues due to hindered sight lines for operators, can damage crops or orchards, and may not be feasible to produce and therefore not made available for purchase due to these reasons.
- Because new mobile agricultural equipment requires larger engine compartments, this may require changes in how crops are planted and grown.
- New mobile agricultural equipment have increased costs due to complex engine management systems that cost more to repair, take longer to repair, are harder to diagnose, require factory or dealer mechanics to repair, and may disrupt operations during critical periods of harvest or weather events.
- Older equipment must be allowed as backup for when newer equipment fails.
- ARB should not require turnover to the cleanest equipment until it is widely available and thoroughly field tested.
- Many technologies exist that can reduce emissions from existing mobile agricultural equipment but are not certified by ARB and cannot legally be used.
- ARB should help people get rid of the oldest equipment rather than require people to buy the newest equipment.
- Replacement equipment for specialized mobile agricultural equipment may no longer be available at any cost or may be cost prohibitive to custom manufacture.
- Specialized equipment should be exempt from regulation due to low usage and high costs.

RESPONSE:
Staff considered a regulation to require turnover to new technology that would require the mobile agricultural equipment fleet in the San Joaquin Valley to turn over to the cleanest technologies by a set compliance schedule. Such a compliance schedule would be designed to accomplish fleet turnover at a faster rate than would

otherwise occur through natural attrition in order to achieve emission reductions that meet SIP attainment goals.

Staff ultimately did not propose such a regulation for several reasons. First, staff estimates that the mobile agricultural equipment turnover from agriculture industry participation in voluntary incentive programs in the San Joaquin Valley that has been occurring and will continue to occur is sufficient to meet the 2007 SIP emission reduction goal of
5 to 10 tons per day of NOx reductions by 2017.

Second, a new 2016 ozone SIP process, based on more stringent 2008 federal standards for 8-hour ozone, will identify additional reductions needed from mobile agricultural equipment with attainment required in 2032. A compliance schedule, however, is not practical to consider at this time because the deployment of cleanest engine technologies (Tier 4 final) are not expected to be widely available in the agricultural sector until 2020.

Third, because Tier 4 final technologies in mobile agricultural equipment are not widely available now, requiring turnover now would result in a mobile agricultural equipment inventory that would not meet the needs for attainment in 2032. This would create a need to require a second turnover of the fleet to Tier 4 final technologies when that equipment becomes available. Requiring the agriculture industry to turnover equipment twice will impose significant increased costs and is not necessary at this time because the voluntary incentive program agricultural equipment projects are meeting the 2007 SIP emission reduction goal.

Finally, to address the new 2008 federal standards and the additional reduction needs that may result during the development of the new SIP, a second mobile agricultural equipment regulation process will include accelerated fleet turnover as one of the strategies to be considered. This subsequent process will address both the remaining emission reduction needs for attainment in 2023 as well as provide additional reductions needed for attainment in 2032.

D. Regarding Economic Impacts

Staff received a number of questions and comments (listed below) regarding economic impacts of the *Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment.*

- A rigorous, balanced, and complete economic analysis is needed to study the potential impacts of a regulation on food prices, consumers, individual farmers and ranchers, and the California agriculture industry as a whole.
- The agriculture industry in California is extremely complex and economic impacts of a regulation will be difficult to accurately predict.

- ARB should consider the cumulative and growing economic impact of all the regulations that California agricultural industry faces other than ARB regulations, such as water, pesticide, and labor regulations.
- Most farmers, ranchers, and dairy operators cannot afford to purchase new equipment, even with help from incentive programs.
- The economics to replace a tractor that doesn't operate for very many hours doesn't make sense, most farmers can't afford to replace low operation equipment, and low operation equipment can't receive incentive funding because it does not meet cost-effectiveness requirements.
- Regulation causes equipment that will become noncompliant in the future to lose value immediately.
- Noncompliant equipment becomes worthless, making the purchase of new equipment even more difficult.
- A mobile agricultural equipment regulation will increase the competitive disadvantage that California already faces with the rest of the country and the world.
- Extra costs imposed on farmers cannot easily be passed along to consumers.

RESPONSE:
These questions are most relevant to the longer-term development process for the 2016 SIP and the next mobile agricultural equipment regulation development. The *Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment* causes no administrative costs on the San Joaquin Air Pollution Control District (SJVAPCD), other air districts, and ARB.

E. Regarding Incentive Programs

Staff received a number of questions and comments (listed below) regarding the mobile agricultural incentive programs that underlay the *Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment.*

- There is not enough incentive funds available to help everyone who needs help to turn over mobile agricultural equipment.
- Relying upon incentive program emission reductions doesn't provide enough emission reductions.
- Incentive funds typically go to the largest operations that don't really need the help.
- Incentive funds typically go to replace mobile agricultural equipment that has the highest use, but most of the oldest/highest polluting equipment has lower usage.
- The process to apply and receive incentive funds is complex and lengthy which discourages all but the largest operations from participation.
- Incentive program contractual requirements, including usage requirements, discourage smaller operations from participating.
- Many who have applied for incentive funding but turned down will not try again.

- Specialized equipment that gets low hours of operation may not qualify for incentive programs.
- Incentive funds should go to manufacturers or dealers to make mobile agricultural equipment more affordable for everyone rather than to purchasers.
- U.S. Department of Agriculture Natural Resources Conservation Service (NRCS) funded projects should be recommended as playing a role in achieving emission reductions that will count towards meeting SIP credit.

RESPONSE:
This regulation is designed to complement SJVAPCD's Rule 9610, adopted by the SJVAPCD Board on June 20, 2013, and recognizes emission reductions achieved through incentive programs administered by SJVAPCD, NRCS, and ARB. In general, this regulation imposes certain minimum administrative and implementation policies and procedures for incentive programs to be eligible to receive SIP credit, but does not otherwise affect the programs.

ARB recognizes the importance of incentive programs for achieving emission reduction goals through accelerating the use of cleaner technology. The existing incentive programs and projects have been producing emission reductions since 2008, and these and subsequent incentive program projects will continue regardless of this regulation. ARB will continue to work cooperatively with stakeholders and other government agencies to identify additional sources of funding for the industry.

F. Regarding Enforcement

Staff received comments (listed below) regarding enforcement of the *Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment.*

- Enforcement by ARB should protect and encourage those who comply or attempt to comply by taking action on those who refuse to comply.
- People who simply can't afford to comply shouldn't be made criminals.
- Enforcement should be fair.
- How does the public ensure that emission reductions are occurring?
- Farmers don't want to register their mobile agricultural equipment because they fear it puts them "in the system" and makes them more vulnerable to enforcement.

RESPONSE:
These comments are most relevant to the longer-term development process for the 2016 SIP and the next mobile agricultural equipment regulation development. This regulation, however, requires SJVAPCD and other air districts to monitor and enforce the projects as required in the Carl Moyer Program Guidelines. Carl Moyer Program Guidelines ensure that emission reductions achieved through funded projects are enforceable. The Carl Moyer Program Guidelines require that emission reductions must be independently and practicably verifiable for the duration of the project life through inspections, monitoring, and other mechanisms. Furthermore,

incentive program violations are defined through legally binding contracts, grants, or vouchers that identify the party or parties responsible for ensuring that emission reductions are achieved. Funding recipients of voluntary incentive program funds are also obligated to provide all records needed to demonstrate that emission reductions are achieved. All emission-related information for reductions claimed must be available for public access.

G. General Comments on this Regulation

Staff received a number of general questions and comments (listed below) regarding the *Proposed Regulation for State Implementation Plan Credit from Mobile Agricultural Equipment.*

- A mobile agricultural equipment regulation should be coordinated and commence later than other ARB regulations such as the Truck and Bus Rule and the Off-Road Compression Ignition Regulation.
- Compliance options should be flexible and provide plenty of time for the regulated community to take action to comply.
- A regulation should be simple to understand.
- A regulation should have ample and effective outreach to ensure that everyone who should know about it does and has time to comply.
- ARB should provide a low-usage exemption for mobile agricultural equipment. (Suggested thresholds range from between 50 to 600 annual hours.)
- Tier 3 and cleaner equipment should be exempt to regulation until 2032.
- There should be a trade-up program so that cleaner equipment remains in the inventory and the oldest/dirtiest is removed.
- All equipment should have a useful life before they are affected by regulation. (Suggested useful lifespans ranged from 15 to 30 years.)
- Regulation should focus on removing uncontrolled and Tier 1 equipment.

RESPONSE:
These comments are not germane to the proposed regulation but pertain to equipment regulations in general and are most relevant to the development process for the 2016 SIP and the next mobile agricultural equipment regulation.

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider adoption of amendments to California's existing Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.), which was developed pursuant to requirements of the California Global Warming Solutions Act of 2006.

DATE: October 24, 2013

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., October 24, 2013, and may continue at 8:30 a.m., October 25, 2013. This item may not be considered until October 25, 2013. Please consult the agenda for the meeting, which will be available at least 10 days before October 24, 2013, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed amendments to sections 95101, 95102, 95103, 95104, 95105, 95110, 95111, 95112, 95113, 95114, 95115, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95129, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, title 17, California Code of Regulations. Proposed adoption of new section 95124 and Appendix B, title 17, California Code of Regulations.

Documents Incorporated by Reference:

1. Definition of Volatile Organic Compounds (VOC). 40 CFR Part 51.100(s). United States Environmental Protection Agency. March 31, 2009. http://www.epa.gov/ttn/naaqs/ozone/ozonetech/def_voc.htm (accessed August 2, 2013)
2. Definition of Toxic Air Contaminant. California Health and Safety Code, Section 39655(a). http://www.leginfo.ca.gov/cgi-bin/displaycode?section=hsc&group=39001-40000&file=39655 (accessed August 2, 2013)

3. ASTM D-70 – 09 "*Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method),*" 2010.

4. ASTM D-287 – 92 "*Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method),*" 2006.

5. ASTM D-1945 – 03 "*Standard Test Method for Analysis of Natural Gas by Gas Chromatography,*" 2003.

6. ASTM D-2597 – 94 "*Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography,*" 2004.

7. ASTM D-3710 – 95 "*Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography,*" 1999.

8. ASTM D-3588 – 98 "*Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels,*" 2003.

9. ASTM D-4007 – 08 "*Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method,*" 2008.

10. ASTM D-4052 – 09 "*Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter,*" 2009.

11. ASTM D-5002 – 99 "*Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer,*" 2010.

12. ASTM D-5504 – 08 "*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence,*" 2008.

13. ASTM D-6228 – 10 "*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection,*" 2010.

14. California Health and Safety Code, Part 3 of Division 26, commencing with Section 40000. *Air Pollution Control Districts.* http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=hsc (accessed August 22, 2013).

15. "*Columbia River Treaty: Treaty between Canada and the United States of America relating to Cooperative Development of the Water Resources of The Columbia River Basin,*" January 17, 1961.

16. EPA Method 15 "*Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources,*" 1996.

17. EPA Method 16 "*Semicontinuous Determination of Sulfur Emissions from Stationary Sources,*" 1996.

18. EPA Method 8021B "*Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/or Electrolytic Conductivity Detectors,*" 1996.

19. EPA Method 8260B "*Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS),*" 1996.

20. EPA Method TO-14 "*Determination of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters with Subsequent Analysis by Gas Chromatography,*" 1999.

21. EPA Method TO-15 "*Determination of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters and Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS),*" 1999.

22. GPA 2174 – 93 "*Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography,*" 1993.

23. GPA 2177 – 03 "*Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography,*" 2003.

24. GPA 2261 – 00 "*Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,*" 2000.

25. GPA 2286 – 95 "*Extended Gas Analysis Utilizing a Flame Ionization Detector,*" 1995.

26. ISO 12625-8:2010 "*Tissue paper and tissue products -- Part 8: Water-absorption time and water-absorption capacity, basket-immersion test method,*" International Standards Organization, 2010.

27. ISO 50001 "*Energy Management Systems – Requirements with Guidance for Use,*" International Standards Organization, 2011.

28. "*Official Methods of Analysis of the Association of Official Analytical Chemists,*" 13th Ed., 1980, sections 32.025 to 32.030, under the heading "Method III (Potentiometric Method)."

29. "*Official Methods of Analysis of the Association of Official Analytical Chemists,*" 13th Ed., 1980, sections 32.014 to 32.016 and 52.012.

30. "*Standards for Gas Service in the State of California, General Order No. 58A.*" State of California, Public Utilities Commission, 1992.

Background and Effect of Proposed Rulemaking:

In 2006, the Legislature passed and Governor Schwarzenegger signed the California Global Warming Solutions Act of 2006 (Assembly Bill 32 (AB 32); Stats. 2006, chapter 488). In AB 32, the Legislature declared that global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of California. AB 32 created a comprehensive, multi-year program to reduce greenhouse

gas (GHG) emissions in California, with the overall goal of restoring emissions to 1990 levels by the year 2020.

One of the requirements of AB 32 is that ARB must adopt a greenhouse gas reporting regulation. To comply with this requirement, the Board approved the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (reporting regulation) at its December 2007 Board meeting. The reporting regulation became effective on January 2, 2009.

Over the past five years, ARB staff has implemented the California greenhouse gas reporting program established by the reporting regulation. Under the program, over 700 facilities and entities annually submit to ARB their GHG emissions data reports, the majority of which are verified as accurate and complete by ARB-accredited third-party verifiers. Information about the program can be found at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

At its December 2010 public hearing, the Board approved amendments to the reporting regulation to support the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (title 17, CCR, section 95800 et seq.) (Cap-and-Trade regulation) data requirements, harmonize to the extent feasible with the United States Environmental Protection Agency's (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases (rule), and align with the Western Climate Initiative (WCI) reporting structure. Those amendments to the reporting regulation became effective on January 1, 2012.

In September 2012, the Board approved additional amendments to the reporting regulation, as well as updates to the definition sections of the AB 32 Cost of Implementation Fee Regulation and the Cap-and-Trade regulation. These updates were necessary to streamline and avoid duplicate GHG reporting, to further align with U.S. EPA's GHG rule, and to continue to provide the highest quality data needed to support California's Cap-and-Trade program. These amendments to the reporting regulation became effective on January 1, 2013. Links to the rulemaking documents are located here: http://www.arb.ca.gov/cc/reporting/ghg-rep/regulation/mrr-regulation.htm.

ARB staff is proposing amendments to the reporting regulation to be heard at the Board's October 24-25, 2013 hearing. The proposed updates are needed to continue to support benchmarking, allocation of allowances and the covered emissions calculation under the Cap-and-Trade regulation; and to ensure that reported GHG emissions data is accurate and complete in order to support California's other climate and GHG reduction programs, including the statewide GHG emission inventory. Staff is not proposing any changes to further align with the U.S. EPA's GHG reporting rule at this time. U.S. EPA is currently undergoing a regulatory amendment process to add in new emission factors, modify emission estimation and calculation methods, and revise global warming potentials but these amendments are not yet final. Once final, ARB will evaluate the revisions to determine whether a future rulemaking action to further amend

the California reporting regulation is necessary.

Objectives and Benefits of the Proposed Regulation:

The purpose of the proposed amendments to the reporting regulation is to carry out the goals of AB 32 and maintain a robust and accurate GHG reporting program. The mandatory reporting program tracks the emissions from reporting entities over time, demonstrating progress in reducing GHG emissions. The proposed amendments will support the Cap-and-Trade regulation with the highest quality of data by collecting additional information to ensure the accuracy of the data used for benchmarking, allocation of allowances, and the covered emissions calculation. Additionally, the amendments will help to make certain that reported GHG emissions data is accurate and complete in order to support emissions reduction programs throughout the state.

Anticipated benefits of the proposed revisions include improved clarity for each reporting entity's reporting and verification obligations, more accurate GHG emissions estimates from corrected or updated emissions calculation methods and emission factors, improved methods to support the accuracy of the statewide GHG inventory program and continued robust methods for reporting emissions and product data in order to support ARB's Cap-and-Trade regulation. These benefits may also result in indirect benefits to the health and welfare of California residents, worker safety, and the state's environment by ensuring that the state has an accurate inventory of GHG emissions to support programs which will reduce emissions and directly improve the health and welfare of California residents, worker safety, and the state's environment.

Below is a summary of proposed updates to the reporting regulation. A more detailed description of the proposed updates appears in the Summary and Rationale section of the Initial Statement of Reasons (ISOR).

Applicability: Proposed revisions in this section have been added to require GHG reporting by facilities in the lead production sector. This sector was specifically not included in prior updates to the reporting regulation, as there was no known lead production facility in the state which met applicability requirements for GHG reporting. With the identification of lead production facilities in the state that meet the applicability requirements, staff is now proposing to include emission and product data requirements in new section 95124. Additionally, staff is also proposing to add emissions and product data reporting requirements for other sectors listed in the U.S. EPA's GHG reporting rule that had previously been excluded from California's reporting regulation due to the lack of identified sources in the state. These sectors will now be required to report if they either meet the applicability requirements or begin industrial operations in the state.

Staff added language to clarify that vented and fugitive emissions must be included in the calculation for the applicability threshold, as well as emissions from hydrogen fuel cell units.

Cessation of Reporting and Verification: Staff has proposed revisions to clarify the cessation of reporting as well as the cessation of verification requirements. The cessation requirements for reporting and verification are now broken out into two separate sections for greater clarity. Additionally, the proposed revisions clarify the different cessation of reporting requirements between the mandatory reporting and Cap-and-Trade regulations.

The revisions specify that a reporting entity must fully comply with the Cap-and-Trade requirements. When a covered entity is no longer subject to the Cap-and-Trade program, the entity must continue to comply with the cessation of reporting and verification requirements.

Definition Clarifications and Additions: Existing definitions were clarified to minimize ambiguity. New definitions were added to support updated provisions described in this staff report, such as new product data categories, new language related to electric power entities, and clarifications of existing terms including emissions data reports, correctable errors, and common control.

Abbreviated Reporters: Additional, minor requirements were added for abbreviated reporters to ensure data compatibility with non-abbreviated emissions data reports. This new data includes attributing percentages of aggregated fuel consumption to the unit type categories specified in section 95115(h), separately reporting electricity generating units from other general stationary combustion units, and including emissions from hydrogen fuel cell units in their reports. Additionally, staff has clarified the requirement for abbreviated reporters to correct known errors in their emissions data reports, if discovered after the original submission of their report, ensuring the most accurate data reporting possible.

Reporting 2013 data in 2014: Because the proposed amendments to this reporting regulation will become effective after the data has been collected for 2013, staff specifically describes reporting of 2013 data in 2014 for new reporting requirements. The language in this section is applicable to new reporting requirements in the following areas: product data reporting requirements found in subarticles 3 and 5; reporting requirements for operators of hydrogen and lead production facilities, suppliers of natural gas, and electric power entities. Provisions are also added for indicating which requirements are applicable for 2014 data reported in 2015.

Metering Requirements: Staff added language to exempt certain non-financial transaction meters used by Public Utility Gas Corporations (PUGCs) from the metering accuracy requirements, if they are operated and maintained in conformance with a standard that meets the measurement accuracy requirements of the California Public Utilities Commission General Order 58A. This was added so that PUGCs do not have to meet two different metering standards for the same meters. Additionally, it ensures the continued accuracy of the non-financial transaction meters by requiring the PUGC to demonstrate accuracy requirements specified in the California Public Utilities

Commission General Order 58A, which is consistent with the existing reporting requirements.

Product Data Reporting: Staff added language to allow exclusions from reporting of covered product data under certain conditions. This new provision applies to all covered product data reporting except for the data reported by the cement sector in section 95110(d). This new provision also includes a requirement for each reporting entity to include which covered product data was excluded, for tracking purposes. These modifications allow increased flexibility for reporting covered product data.

Facility Ownership: To clarify the reporting and verification responsibilities during a change of ownership, staff has proposed amendments that specify the steps which must be taken by the parties, and who is responsible for reporting. This ensures the consistent and continuous reporting of a reporting entity.

Reporting Data to Support the Adaptive Management Plan for the Cap-and-Trade Regulation: Staff added a requirement for facilities to indicate if their non-GHG emissions (i.e., criteria and toxic pollutant emissions) may have increased since the last reporting period, and the reason for such potential increases. This information will be used to support the Adaptive Management Plan for the Cap-and-Trade regulation. Specifically, the data collected will be used to provide on-going evaluation and adjustments to the Cap-and-Trade regulation, as it relates to localized air quality impacts due to implementation.

Recordkeeping Requirements: All facilities with greater than 25,000 metric tons CO_2e of emissions must prepare and maintain a GHG Monitoring Plan. New language specifies that this applies also to biomass-derived CO_2 emissions, geothermal emissions, and fuel suppliers. Maintaining a GHG Monitoring Plan helps to ensure compliance and best practices, facilitate more efficient verification, and provide a consistent treatment among the facilities at the greater than 25,000 metric tons CO_2e emission level.

Electric Power Entities: The proposed amendments for electric power entity reporting address issues related to specified source and asset-controlling supplier power claims. The amendments would build on requirements developed in the 2012 rulemaking to more clearly distinguish between specified, unspecified, and asset-controlling supplier power products. The amendments proposed for system power language would require purchasers of system power that has a carbon content above the default emission factor to report imported power using a system power emission factor calculated by ARB, instead of the lower default emission factor for unspecified power, in order to accurately reflect the carbon content of the system power.

Multiple Electricity Generation and Cogeneration Units with Multiple Dedicated End Users: Under the proposed revisions, if a facility includes more than one cogeneration (cogen) system or electricity generating unit and provides or sells generated energy to more than one end user, and the generated energy from the multiple units is not mixed before being supplied to a particular end user, the entity must report the energy

disposition by unit or system. This requirement does not apply if the energy generated by multiple units is commingled and supplied to the same end users. It enables the assessment of carbon cost pass-through from the cogen facility operator to their thermal hosts, separately from other units that are not part of the cogen system.

Cooling Energy: New language proposed by staff requires facility operators to provide information about thermal energy which is used to produce cooling energy or distilled water for a customer outside of its facility boundary or for on-site industrial processes or operations that are neither in support of nor a part of the power generation system. This new requirement allows affected reporting entities to complete their system energy balance.

Refineries: Proposed updates in this section include clarifying text describing the verification of primary refinery products and the Solomon EII value. The proposed revisions outline which verification requirements need to be followed for present and future data submissions. A new reporting requirement added to annually determine the density of each carbon weighted tonne throughput will allow for an accurate assessment of this covered product data. Additionally, complexity weighted barrel requirements were added to support the allocation of allowances in the Cap-and-Trade program. The complexity weighted barrel requirements are similar to the carbon dioxide weighted tonne throughputs, but are reported in barrels as opposed to metric tons of throughput.

Updates have also been made so that refineries who also supply transportation fuels report the transportation fuels under a separate ARB ID from the refinery. This ensures that the covered refinery emissions are reported and verified separately from the fuel supplier emissions It also clarifies verification requirements by requiring verifiers to consider the refinery emissions separately from the supplier emissions, thereby facilitating an effective verification of the transportation fuel.

Hydrogen Fuel Cells: The past few years has seen a growth in installation of new hydrogen fuel cell units. To support the state-wide inventory of electricity generation emissions and to help ARB monitor the growth in hydrogen fuel cell installations, emission calculation methods for hydrogen fuel cell are added.

Hydrogen Production: Staff is also proposing several new requirements for hydrogen production facilities. The source category description has been edited to include facilities which do not sell hydrogen, but rather consume all the hydrogen they produce on-site (e.g., R&D facilities). To support both the GHG statewide inventory, new requirements have been added which require reporting of carbon and hydrogen content and CH_4 and N_2O combustion emissions. Reporters will also be required to report the amount of on-purpose and by-product hydrogen production at their facility. Reporters will need to include their flaring emissions, a requirement that was originally in the 2007 version of the reporting regulation, but was inadvertently omitted during the harmonization with the U.S. EPA rule. Finally, reporters will be required to adjust their facility emissions for both transferred CO_2 to guard against double-counting and provide data consistency for all report facilities. These updates support the development of an

accurate GHG inventory and support benchmarking and allocation analyses in the Cap-and-Trade program.

Stationary Combustion Sources: Staff revised this section to simplify emissions estimation for biomass-derived fuel, allowing use of the Tier 1 or Tier 2 methodologies when biomass fuels are mixed with fossil fuels. Staff also provided a correction for the aggregated data reporting requirement, so fuel use percentages are reported instead of heat input values, which is consistent with the reporting tool inputs. Staff also added new product data reporting requirements for several industrial sectors. This additional reporting is needed for Cap-and-Trade benchmarking and allocation of free allowances to the affected sectors.

Lime Production Emissions: For some industrial sectors that produce lime, the CO_2 produced is reintroduced into the manufacturing process and not released into the atmosphere. Staff has proposed updated emissions estimation method accounts for CO_2 reinjected and recovered in production, so emissions can be treated appropriately in the Cap-and-Trade program.

Fuel Suppliers: Several revisions have been added for suppliers of transportation fuels, natural gas, natural gas liquids, and liquefied natural gas (LNG). The first allows all fuel suppliers to use *de minimis* provisions in reporting. This ensures consistency with other reporting entities, which already are allowed to use *de minimis* provisions. For transportation fuel suppliers, staff added language to delineate which fuels are required to be reported. Specifically, the new language clarifies that fuel used for aviation or marine purposes is not reported as a transportation fuel, primarily because the fuel is largely combusted outside of California.

In addition, staff also revised the definition and reporting requirements for operators of intrastate pipelines to better clarify the applicability and reporting requirements for operators of intrastate pipelines delivering natural gas. This addition was made to ensure consistent and complete reporting of all natural gas delivered to end-users within California. New provisions affecting natural gas utilities were also added, which require utilities to report customer data regarding deliveries to smaller end-users and 're-deliveries' to other natural gas utilities. The new reporting requirements will enhance ARB staff's ability to accurately and promptly determine the covered emissions value for the natural gas utilities.

Lastly, additions were made to the applicability requirements and reporting requirements that require all liquefied natural gas production facilities to quantify and report emissions from delivered LNG product if the facility is receiving the natural gas feedstock for the liquefaction process from an interstate pipeline. This addition ensures that there are no gaps in reporting natural gas supplied in California.

Petroleum and Natural Gas Systems: The majority of the proposed changes to Subarticle 5 will correct clerical references, address past omissions, and provide additional clarity. The definition of an onshore petroleum and natural gas production

facility was clarified to support the allocation of allowances in the Cap-and-Trade program. Additional edits provide clarity to the reporting of stationary combustion emissions, particularly combustion emissions associated with non-pipeline quality natural gas. Staff has also proposed new language to require reporting of emissions from completions and workovers from oil wells in addition to gas wells. This will result in more complete emissions coverage as the majority of wells in California are for oil.

To address cost concerns, staff has proposed revisions to add flexibility in leaker emission reporting by allowing the use of both the population counts and the sampling method for estimating emissions.

Staff has also added new language to require that the amount of dry gas produced is also reported. While this was optional in prior data years, it is now required to support Cap-and-Trade allowance allocations. Other new language requires the reporting of the crude fraction and associated gas fraction of emulsion piped as an emulsion as defined in section 95102(a), also to support Cap-and-Trade allowance allocation. Finally, staff proposed that onshore natural gas processing facilities with an annual throughput of 25MMscf/day or more are required to report volumes of gas processed.

Flash Liberation Test: ARB staff has proposed to add in a new test procedure, which details an ARB methodology for the testing and determination of produced water, crude oil and condensate emissions via a flash liberation test. This procedure is a cost-effective method of determining gas-to-oil and gas-to-water ratios for oil wells. The test procedure is included in new Appendix B of this regulation.

Verification: Several provisions related to verification services and verification bodies have been updated. New language clarifies specific requirements for the conformance evaluation. Staff is also proposing updates to allow for multiple product data verification statements in cases where multiple product types are reported (e.g., primary refinery products and carbon weighted tonne). Staff has also added language to clarify the intent of the correctable error requirements in section 95131(b)(9).

Staff added language to clarify requirements of liability insurance for verification bodies, as well as simplifying the withdrawal requirements for verification bodies who no longer wish to participate in the mandatory reporting program. Clarifying language allows verification bodies to perform multiple third-party verification services for the same reporting entity under the auspices of different GHG reporting programs, and avoid a high conflict determination, provided that the verification body continues to observe the requirements of mandatory reporting conflict of interest determination.

General: Staff has proposed modifications in a number of other sections, in order to maintain consistency in the structure of the regulation. None of these minor modifications are intended to alter requirements – several of the updates or additions correct clerical oversights and references, while others renumber sections for uniformity with the remainder of the reporting regulation.

DETERMINATION OF INCONSISTENCY AND INCOMPATIBILITY WITH EXISTING STATE REGULATIONS

During the process of developing the proposed regulatory action, ARB has conducted a search of any similar regulations on this topic and has concluded that these regulations are neither inconsistent nor incompatible with existing state regulations.

MANDATED BY FEDERAL LAW OR REGULATION

This regulation is not mandated by federal law or regulations.

COMPARABLE FEDERAL REGULATIONS

As mentioned previously, the U.S. EPA requires mandatory GHG reporting (*Mandatory Reporting of Greenhouse Gases; Final Rule.* 40 CFR Parts 86, 87, 89, 90, 94, and 98. United States Environmental Protection Agency. October 30, 2009). Staff does not believe the proposed regulation is inconsistent with existing federal law. In fact, this proposed amended regulation was developed to minimize, to the greatest extent possible, any redundant State and federal reporting, while also ensuring that ARB is collecting the necessary additional information required by California's various GHG programs, including the Cap-and-Trade regulation, fee regulation, and the statewide GHG inventory.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The ISOR is entitled: "Staff Report: Initial Statement of Reasons for Rulemaking: Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions."

Copies of the ISOR and the full text of the proposed regulatory language may be accessed on ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990 on September 4, 2013.

Final Statement of Reasons Availability

Upon its completion, a Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on ARB's website listed below.

Agency Contact Persons

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Dr. David Edwards, Manager of ARB Climate Change Reporting Section, Air Quality Planning and Science Division at (916) 323-4887, or Ms. Joelle Howe, Air Pollution Specialist, at (916) 322-6349.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed is Ms. Trini Balcazar, Regulations Coordinator, (916) 445-9564. The Board staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

Internet Access

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013.htm.

DISCLOSURES REGARDING THE PROPOSED REGULATION

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below. Chapter VI of the ISOR for the proposed regulation includes additional data on the estimated costs to affected entities.

Fiscal Impact / Local Mandate

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would result in a marginal cost increase to 6 state agencies (universities and prison) and 21 local government entities (power plants, wastewater treatment plants, landfills, and airports operated by local government entities). ARB estimated that each affected state agency may see an incremental cost increase of approximately $1,000 in the first year and $230 in the on-going years. Each affected local government entity may see an incremental cost increase of approximately $1,200 in the first year and $250 in the on-going years.

Because the regulatory requirements apply equally to all reporting categories 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 that is required to be reimbursed pursuant to Section 6 of Article XIII B of the California Constitution. In addition, there are no other nondiscretionary costs or savings imposed upon local agencies.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would not create costs or savings in federal funding to the state, or costs or mandate to any school district whether or not reimbursable by the state pursuant to Part 7 (commencing with section 17500), division 4, title 2 of the Government Code.

Adoption of the proposed revisions has no additional fiscal impact on ARB. No change in staffing level is needed to administer the program under the revised rule. ARB fiscal

expenses needed for integrating the proposed amendments into the existing reporting systems are already accounted for in the current operational budget that was proposed in the previous amendment to the rule.

Significant Statewide Adverse Economic Impact Directly Affecting Business, Including Ability to Compete

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states.

Cost Impacts on Representative Private Persons or Businesses

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative businesses and determined that private businesses may see an incremental cost increase as the result of the proposed regulatory action. Approximately half of all the businesses currently subject to the existing reporting regulation may experience a cost increase due to the proposed action; while the other businesses are not expected to see a noticeable change in cost of compliance.

ARB staff estimates that the amended requirements will lead to a cost increase of $56 million for private business entities over 8 years. For an average private business entity not in the oil and gas sector, the amendments are expected to result in an average annual cost increase of approximately $3,480 in the initial year and $2,300 in the ongoing years per business entity (which may operate multiple facilities, each of which may be impacted by the regulation amendments differently). Although the cost impacts to individual businesses in the oil and gas sector are expected to vary widely depending on the scale of their operations, the average incremental cost per company is estimated to be approximately $479,000 in the initial year and ongoing years. Staff estimated that 98.5% of all the cost impacts occur in the oil and gas sector.

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide economic impact directly affecting representative private persons.

Results of the Economic Impact Assessment Prepared Pursuant to Government Code Sec. 11346.3(b)

Effect on Jobs/Businesses:

The Executive Officer has determined that the proposed regulatory action would not affect the creation or elimination of jobs within the State of California, the creation of new businesses or elimination of existing businesses within the State of California, or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in Chapter VI Economic Impacts of the ISOR.

Benefits of the Proposed Regulation:

Anticipated benefits of the proposed revisions include improved clarity for reporting entity's reporting and verification obligations, more accurate GHG emissions estimates from corrected or updated emissions calculation methods and emission factors, improved methods to support the accuracy of the statewide greenhouse inventory program and continued robust methods for reporting emissions and product data in order to support ARB's Cap-and-Trade regulation. These benefits may also result in indirect benefits to the health and welfare of California residents, worker safety, and the state's environment by ensuring that the state has an accurate inventory of GHG emissions to support programs which will reduce emissions and directly improve the health and welfare of California residents, worker safety, and the state's environment. A further discussion on the economic impacts of the proposed regulatory action can be found in the Economic Impact Analysis in the ISOR.

Effect on Small Business

The Executive Officer has also determined, pursuant to California Code of Regulations, title 1, section 4, that the proposed regulatory action would not affect small businesses because none of the affected companies qualify for the small business status based on the California Government Code section 11342.610 definition.

Housing Costs

The Executive Officer has also made the initial determination that the proposed regulatory action will not have a significant effect on housing costs.

Business Report

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Alternatives

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed, would be as effective and less burdensome to affected private persons than the proposed action, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provision of law. Since the proposed amendments are made to the existing reporting regulation, and given that these proposed amendments do not have a significant adverse fiscal or economic impact, no alternatives, other than one in which no regulatory amendments would be made and ones in which the specific amendments to various sector requirements are compared to harmonization with the applicable U.S. EPA rule requirements or data collected from other sources, were considered. These alternatives are fully described in Chapter II of the ISOR.

Environmental Analysis

In accordance with ARB's certified regulatory program, California Code of Regulations, title 17, sections 60006 through 60007, and the California Environmental Quality Act, Public Resources Code section 21080.5, ARB has conducted an analysis of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulatory action. The environmental analysis of the proposed regulatory action can be found in Chapter IV of the ISOR.

WRITTEN COMMENT PERIOD AND SUBMITTAL OF COMMENTS

Interested members of the public may present comments relating to this matter orally or in writing at the meeting, and may provide comments by postal mail or electronic submittal before the meeting. The public comment period for this regulatory item will begin on September 9, 2013. To be considered by the Board, written submissions not physically submitted at the hearing must be submitted on or after September 9, 2013, and received **no later than 12:00 noon, October 23, 2012**, and must be addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

You can sign up online in advance to speak at the Board meeting when you submit an electronic board item comment. For more information go to: http://www.arb.ca.gov/board/online-signup.htm

Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and verbal comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

ARB requests that written and email statements on this item be filed at least 10 days prior to the hearing so that ARB staff and Board members have additional time to consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

Additionally, the Board requests but does not require that persons who submit written comments to the Board reference the title of the proposal in their comments to facilitate review.

AUTHORITY AND REFERENCES

This regulatory action is proposed under that authority granted in Health and Safety Code, sections 38510, 38530, 38560, 38562, 38564, 38570, 38571, 38580, 38597, 39600, 39601, 39607, 39607.4, and 41511. This action is proposed to implement, interpret and make specific sections 38501, 38505, 38510, 38530, 38560.5, 38564, 38565, 38570, 38580, 38597, 39600, 39601, 39607, 39607.4, and 41511 of the Health and Safety Code.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed or with nonsubstantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action. In the event that such modifications are made, the full regulatory text, with the modifications clearly indicated, will be made available to the public for written comment at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Consistent with California Government Code Section 7296.2, special accommodation or language needs may be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format or another language;
- A disability-related reasonable accommodation.

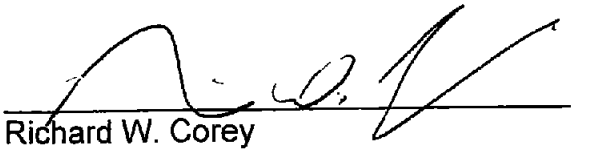
To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Consecuente con la sección 7296.2 del Código de Gobierno de California, una acomodación especial o necesidades lingüísticas pueden ser suministradas para cualquiera de los siguientes:

- Un intérprete que esté disponible en la audiencia
- Documentos disponibles en un formato alterno u otro idioma
- Una acomodación razonable relacionados con una incapacidad

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envié un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD



Richard W. Corey
Executive Officer

Date: August 27, 2013

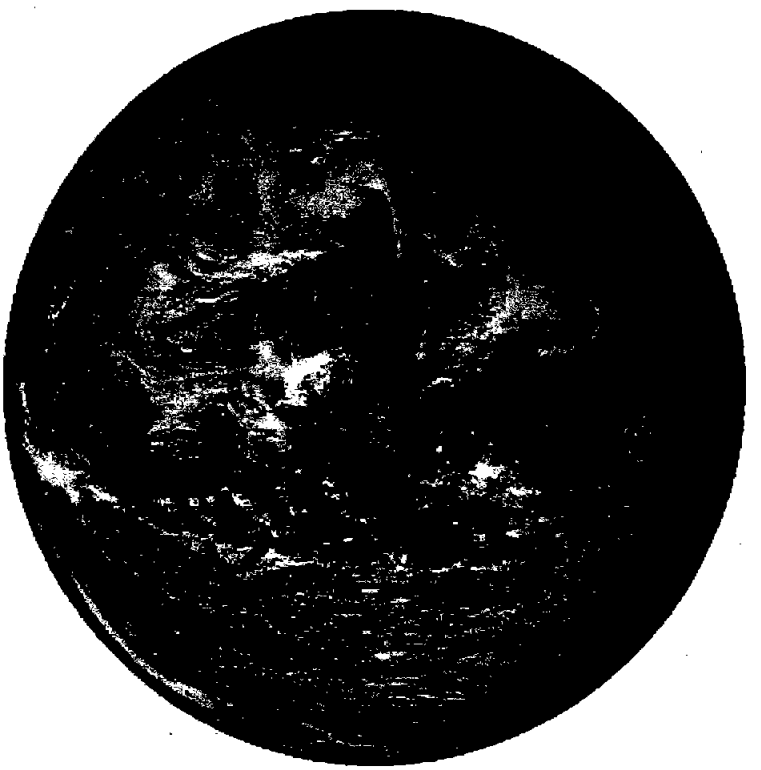
The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website at www.arb.ca.gov.

California Environmental Protection Agency

Air Resources Board

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS



Air Quality Planning and Science Division
Greenhouse Gas Emission Inventory Branch

September 4, 2013

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State of California

AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

PUBLIC HEARING TO CONSIDER AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Air Resources Board Meeting

October 24, 2013 at 9:00 a.m.

Air Resources Board

Cal/EPA Headquarters

Byron Sher Auditorium

1001 I Street

Sacramento, CA 95814

Date of Release: **September 4, 2013**

Scheduled for Consideration: **October 24, 2013**

Questions

If you have questions concerning this report, please contact:

Dr. David Edwards
Manager,
Climate Change Reporting Section
Phone: (916) 323-4887
Email: dedwards@arb.ca.gov

or

Ms. Joelle Howe
Air Pollution Specialist,
Climate Change Reporting Section
Phone: (916) 322-6349
Email: jhowe@arb.ca.gov

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

Prepared By:

Air Quality Planning and Science Division
Greenhouse Gas Emission Inventory Branch
Climate Change Reporting Section
Emissions Quality Assurance and Verification Section

Reviewed by
Office of Legal Affairs
Air Quality Planning and Science Division
Stationary Source Division

Acknowledgments

This staff report was prepared with the assistance and support of many individuals within the Air Resources Board. In addition, staff would like to acknowledge the assistance and cooperation of many private individuals and organizations, whose contributions throughout the regulation development process have been invaluable.

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EXECUTIVE SUMMARY

Air Resources Board (ARB or Board) staff is proposing to amend the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions (reporting regulation) to ensure the reported GHG data are accurate and fully support the California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanisms (title 17, California Code of Regulations, section 95800 et seq.) (Cap-and-Trade Regulation) as well as California's statewide greenhouse gas emission inventory and other ARB climate change programs.

This staff report presents ARB staff's proposal to amend the reporting regulation. The staff report discusses the reasons for the proposed amendments and the potential impacts from the regulatory changes. The proposed amendments represent minor but necessary revisions to the current reporting regulation. Staff is not proposing major changes to GHG reporting requirements; however flexibility will be added to the reporting regulation to include new industrial sectors that are included in the United States Environmental Protection Agency (U.S. EPA) GHG reporting rule, but not currently included in the reporting regulation. The proposed changes correct or clarify the reporting requirements necessary for submittal of complete and accurate emission data reports, and add or modify data elements for product data reporting necessary to support the Cap-and-Trade program. Further, as discussed below, ARB is not planning to harmonize with U.S. EPA draft rule changes until the final rule changes are approved.

Background

The Global Warming Solutions Act of 2006 (Assembly Bill 32, or AB 32) requires California to cut greenhouse gas emissions to 1990 levels by 2020 and to develop a comprehensive strategy to reduce dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and public health. AB 32 also requires the ARB to adopt regulations for the mandatory reporting of greenhouse gas emissions in order to monitor and enforce compliance with ARB's GHG emissions reduction actions, including market-based compliance mechanisms. The reporting regulation was originally developed and adopted by the Air Resources Board (ARB) in December 2007. In December 2010, the Board adopted amendments to the reporting regulation in order to harmonize with the GHG reporting requirements of the U.S. EPA, to support California's Cap-and-Trade program, and to ensure consistency with the Western Climate Initiative (WCI) reporting structure. In September 2012, the Board adopted further amendments to the reporting regulation in order to continue harmonization with the U.S. EPA, as well as add conforming definitions to the Cap-and-Trade Regulation and the AB 32 Cost of Implementation Fee Regulation.

Since the Board's December 2012 action, ARB staff has identified additional clarifications to the California regulatory requirements that are needed to support a market-based Cap-and-Trade program. Similar to previous amendments to the reporting regulation, ARB staff intends to continue efforts to harmonize with U.S. EPA rule revisions, to the extent feasible and where appropriate. U.S. EPA is currently undergoing a regulatory amendment process to revise global warming potentials, add in new emission factors, and modify calculation methods, but these amendments are not

yet final. Once final, ARB will evaluate the revisions to determine whether a future rulemaking action to further amend the California reporting regulation is necessary.

Objectives of the Proposed Updates Amendments

ARB staff has proposed amendments to the regulations in order to:

- Continue to support California's Cap-and-Trade program by requiring further information in order to ensure consistency with benchmarking, allocation of allowances, and supporting the covered emissions calculation; and
- Ensure that reported GHG emissions data is accurate and complete in order to support California's GHG reduction programs, including the statewide GHG emission inventory.

The proposed amendments to the mandatory reporting regulation do not change the overall reporting structure. Requirements were added for lead production. In addition, flexibility has been added to capture new sectors as defined in the U.S. EPA GHG reporting rule, as they become applicable to mandatory reporting in California. The verification requirements remain the same, although staff is proposing clarifications for assessing product data material misstatements and addressing correctable reporting errors. These proposed amendments improve upon, clarify, and add to the existing requirements. Product data elements and requirements were added and updated to ensure facilities have the opportunity to receive their full allotment of allowance allocations under the Cap-and-Trade program.

Overview of the Proposed Amendments

Table ES-1provides summaries of the key amendments proposed to the regulations. More complete descriptions of the proposed amendments are found in the succeeding chapters of this report.

Table ES-1
Summary of Proposed Regulatory Amendments to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions

Topic/Sector	Proposed Regulatory Update
General Applicability	• Add the lead production sector to the applicability section • Clarify the cessation of reporting requirements. • Add a section on cessation of verification requirements to ensure consistent interpretation of these requirements. • Add other U.S. EPA industry sectors • Add fuel cell emissions to applicability threshold
Petroleum and Natural Gas Production	• Clarify the definition of onshore petroleum and natural gas production facility • Update leaker emissions reporting to allow for both a population counts and a sampling method for emissions estimation • Add flash liberation test to determine emissions from produced water. This test has been added as Appendix B to the regulation. • Clarify several product data reporting requirements to support the allocation of allowances under the Cap-and-Trade program
Lime Production Emissions	• Update emissions estimation method for carbon dioxide reabsorbed during the production process
Fuel Suppliers	• Modify requirements to aid in the calculation of the Cap-and-Trade compliance obligation • Clarify definitions to support the reporting requirements
Lead Production	• Add new emissions and product data reporting requirements for this sector
Facility Ownership	• Clarify reporting and verification responsibilities during ownership change
Product Data	• Add product data in manufacturing and production categories to assist with Cap-and-Trade allowance allocation and benchmarking. This includes the food processing sector and lead production • Add product data reporting requirements for refineries to include the complexity weighted barrel throughputs.
Stationary Combustion	• Add reporting requirements for fuel cell emissions • Require reporting of supplementary data for bio-methane producers
Electric Power Entities	• Clarify that sellers of specified power must warrant or guarantee that the power sold was actually acquired as specified source power, not re-marketed unspecified power • Add supporting documentation requirements for specified source busbar claims that do not use the transmission loss factor • Clarify the existing requirement that asset-controlling supplier (ACS) power must be reported as unspecified, when not acquired

Topic/Sector	Proposed Regulatory Update
	as a specified source • Add a requirement that purchasers of system power with a carbon content above the default emission factor must report using a system power emission factor rate as determined by ARB, instead of at the unspecified rate, in order to reflect system power carbon content
Hydrogen	• Modify reporting requirements to prevent double-counting with regards to transferred carbon dioxide • Add product data reporting requirements to support the Cap-and-Trade program
Verification	• Clarify requirements of verification to include specific nonconformance checks • Allow for optional exclusion of certain covered product data from the product data material misstatements determination. This requirement applies to all covered product data, except for the cement sector • Add provisions for multiple verification statements in cases where multiple products are being reported (e.g., primary refinery products and CO_2 weighted tonne)
Inventory Support	• Add requirements to hydrogen production to support the state-wide greenhouse gas emissions inventory • Add unit aggregation requirements for abbreviated reporters to enable consistent reporting for electricity generators
Adaptive Management Support	• Add requirement for facility operators to indicate whether facilities' criteria or air toxics pollutant emissions have increased since the last reporting period

Staff Recommendation

Staff recommends that the Board adopt the proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

I. INTRODUCTION AND BACKGROUND

This staff report presents proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions, developed pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32 or AB 32).

A. Overview of Prior Regulatory Actions

The Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (reporting regulation) was originally developed pursuant to AB 32, and adopted by the Air Resources Board (ARB or Board) in December 2007 (ARB MRR 2007). In December 2010, ARB adopted substantial revisions to the original regulation to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements contained in title 40, Code of Federal Regulations (CFR), Part 98; to support a California greenhouse gas (GHG) Cap-and-Trade program; and to align with the Western Climate Initiative (WCI) reporting structure, which became effective on January 1, 2012. Revisions were made in 2012 to continue alignment with U.S. EPA, further support the Cap-and-Trade program, the Cost of Implementation Fee Reg and the statewide GHG inventory. These revisions became effective January 1, 2013. The full regulatory record and background for these three previous GHG reporting regulation rulemakings is available here:

http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm (ARB MRR 2007)
http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm (ARB MRR 2010)
http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm (ARB MRR 2012)

B. Specific Purpose for the Adoption of the Proposed Regulatory Revisions

ARB staff has proposed amendments to the regulations in order to:

- Continue to support California's Cap-and-Trade program by clarifying reporting requirements for the covered emissions calculation, product data verification procedures, and adding additional product data reporting; and
- Clarify that reported GHG emissions data is accurate and complete in order to support California's GHG reduction programs, including the statewide GHG emission inventory.

Similar to past rulemakings, ARB staff notes that it intends to continue efforts to harmonize with U.S. EPA rule revisions, to the extent feasible and where appropriate. U.S. EPA is currently undergoing a regulatory amendment process to add in new emission factors, modify calculation methods, and revise global warming potentials but these changes are not final. These amendments may become final in the federal rules later this year. Once final, ARB will evaluate the revisions to determine whether a future rulemaking action to further amend the California reporting regulation is necessary.

The proposed amendments to the reporting regulation are necessary to further ensure complete and accurate GHG reporting by clarifying reporting requirements, updating emission estimation methods and emission factors, clarifying verification requirements,

and including additional or modified definitions reflecting the other modifications. The proposed amendments do not change the overall reporting structure of the reporting regulation; however flexibility has been added to the regulation to accommodate new sectors reaching reporting applicability in California.

II. STATEMENT OF REASONS

A. DESCRIPTION OF PROBLEM PROPOSAL IS INTENDED TO ADDRESS

In order to carry out the goals of AB 32, a robust and accurate greenhouse gas reporting program is necessary to track emissions from reporting entities over time and to demonstrate progress in reducing GHG emissions. Additionally, the reported data are the foundation of the California Cap-and-Trade program and must be complete and accurate in order to successfully implement the market program. The proposed amendments to add new emission and product data reporting requirements and to clarify several reporting and verification provisions utilized by the reporting program are necessary to support the GHG emissions reduction goals of AB 32 and the Cap-and-Trade program.

This chapter includes a discussion of proposed revisions to the regulations in Section B, and the Rationale to those proposed revisions in Section C. All changes are discussed in further detail in Chapter VII, Summary and Rationale.

B. PROPOSED SOLUTIONS TO THE PROBLEM

This section includes a discussion of some of the key proposed revisions to the reporting regulation. The general rationale for the updates is to support the Cap-and-Trade program and to support the GHG emissions inventory. In supporting the Cap-and-Trade program, data is needed to calculate reporting entities' compliance obligations, for benchmarking, and for allowance allocation. For GHG emissions inventory support, additional requirements and new calculations methods for reporters as well as more specific verification requirements give a clearer picture of the current portfolio of GHGs in the state, and a better understanding of the progress towards future GHG emissions goals. The sections below are not an exhaustive list, but do provide an overview of the proposed updates.

Applicability: Proposed revisions in this section have been added to require GHG reporting by facilities in the lead production sector. This sector was specifically not included in prior updates to the reporting regulation, as there was no known lead production facility in the state which met applicability requirements for GHG reporting. With the identification of lead production facilities in the state that meet the applicability requirements, staff is now proposing to include emission and product data reporting requirements in new section 95124. Additionally, staff is also proposing to add emissions and product data reporting requirements for other industrial sectors listed in the U.S. EPA's GHG reporting rule that had previously been excluded from California's

reporting regulation due to the lack of identified sources in the state. Facilities in these sectors will now be required to report if they either meet the applicability requirements or begin industrial operations in the state rather than waiting for a rulemaking to add them.

Staff also added language to clarify that vented and fugitive emissions must be included in the calculation for the emissions applicability threshold, as well as including emissions from hydrogen fuel cell units.

Cessation of Reporting and Verification: Staff has proposed revisions to clarify the cessation of reporting as well as the cessation of verification requirements. The cessation requirements for reporting and verification are now broken out into two separate sections for greater clarity. Additionally, the proposed revisions clarify the different cessation of reporting requirements between the mandatory reporting and Cap-and-Trade regulations.

The revisions specify that a reporting entity must fully comply with the Cap-and-Trade requirements. When a covered entity is no longer subject to the Cap-and-Trade program, the entity must continue to comply with the cessation of reporting and verification requirements.

Definition Clarifications and Additions: Existing definitions were clarified to eliminate ambiguity. New definitions were added to support updated requirements, such as new product data categories, modified requirements for electric power entities, and clarifications of existing terms including emissions data reports, correctable errors, and common control.

Abbreviated Reporters: Additional, minor requirements were added for abbreviated reporters to ensure data compatibility with non-abbreviated emissions data reports. This new data includes attributing percentages of aggregated fuel consumption to the unit type categories specified in section 95115(h), separately reporting electricity generating units from other general stationary combustion units, and including emissions from hydrogen fuel cell units in their reports. Additionally, staff has clarified the requirement for abbreviated reporters to correct known errors in their emissions data reports, if discovered after the original submission of their report, ensuring the most accurate data reporting possible.

Reporting 2013 data in 2014: Because the proposed amendments to this reporting regulation will become effective after the data has been collected for 2013, staff specifically describes reporting of 2013 data in 2014 for new reporting requirements. The language in this section is applicable to new reporting requirements in the following areas: product data reporting requirements found in subarticles 3 and 5; reporting requirements for operators of hydrogen and lead production facilities, suppliers of natural gas, and electric power entities. Provisions are also added for indicating which requirements are applicable for 2014 data reported in 2015.

Metering Requirements: Staff added language to exempt certain non-financial transaction meters used by Public Utility Gas Corporations (PUGCs) from the metering accuracy requirements, if they are operated and maintained in conformance with a standard that meets the measurement accuracy requirements of the California Public Utilities Commission General Order 58A. This was added so that PUGCs do not have to meet two different metering standards for the same meters. Additionally, it ensures the continued accuracy of the non-financial transaction meters by requiring the PUGC to demonstrate accuracy requirements specified in the California Public Utilities Commission General Order 58A, which is consistent with the existing reporting requirements.

Product Data Reporting: Staff added language to allow reporters the option to exclude covered product data from the product data material misstatement calculation under certain conditions. This new provision applies to all covered product data reporting except for the data reported by the cement sector in section 95110(d). This new provision also includes a requirement for each reporting entity to identify which covered product data was excluded and estimate of amount, for tracking purposes. These modifications allow increased flexibility for reporting and use of covered product data while reducing the opportunities for unintended consequences for unforeseen data losses.

Facility Ownership: To clarify the reporting and verification responsibilities during a change of ownership, staff has proposed amendments that specify the steps which must be taken by the parties, and who is responsible for reporting. This ensures the consistent and continuous reporting of emissions and product data from subject facilities following a change in ownership.

Reporting Data to Support the Adaptive Management Plan for the Cap-and-Trade Regulation: Staff added a requirement for facilities to indicate if their non-GHG emissions (i.e., criteria and toxic pollutant emissions) may have increased since the last reporting period, and the reason for such potential increases. This information will be used to support the Adaptive Management Plan for the Cap-and-Trade regulation. Specifically, the data collected will be used to provide on-going evaluation and adjustments to the Cap-and-Trade regulation, as it relates to localized air quality impacts due to implementation.

Recordkeeping Requirements: All facilities with greater than 25,000 metric tons CO_2e of covered emissions must prepare and maintain a GHG Monitoring Plan. New language specifies that this requirement also applies to facilities with biomass-derived CO_2 emissions, geothermal emissions, and fuel suppliers. Maintaining a GHG Monitoring Plan helps to ensure compliance and best practices, facilitate more efficient verification,

and provide a consistent treatment among the facilities at the greater than 25,000 metric tons CO_2e emission level.

Electric Power Entities: The proposed amendments for electric power entity reporting address issues related to specified source and asset-controlling supplier power claims. The amendments would build on requirements developed in the 2012 rulemaking to more clearly distinguish between specified, unspecified, and asset-controlling supplier power products. The amendments proposed for system power language would require purchasers of system power that has a carbon content above the default emission factor to report imported power using a system power emission factor calculated by ARB, instead of the lower default emission factor for unspecified power, in order to accurately reflect the carbon content of the system power.

Multiple Electricity Generation and Cogeneration Units with Multiple Dedicated End Users: Under the proposed revisions, if a facility includes more than one cogeneration (cogen) system or electricity generating unit and provides or sells generated energy to more than one end user, and the generated energy from the multiple units is not mixed before being supplied to a particular end user, the entity must report the energy disposition by unit or system. This requirement does not apply if the energy generated by multiple units is commingled and supplied to the same end users. It enables the assessment of carbon cost pass-through from the cogen facility operator to their thermal hosts, separately from other units that are not part of the cogen system.

Cooling Energy: New language proposed by staff requires facility operators to provide information about thermal energy which is used to produce cooling energy or distilled water for a customer outside of its facility boundary or for on-site industrial processes or operations that are neither in support of nor a part of the power generation system. This new requirement allows affected reporting entities to complete their system energy balance.

Refineries: Proposed updates in this section include clarifying text describing the verification requirements for primary refinery products and the Solomon EII value. The proposed revisions outline which verification requirements need to be followed for present and future data submissions. A new reporting requirement was added to annually determine the density of each carbon dioxide weighted tonne throughput to allow for an accurate assessment of this covered product data. Additionally, complexity weighted barrel requirements were added to support the allocation of allowances in the Cap-and-Trade program. The complexity weighted barrel requirements are similar to the carbon dioxide weighted tonne throughputs, but are reported in barrels as opposed to metric tons of throughput.

Updates have also been made so that refineries who also supply transportation fuels must report the transportation fuels under a separate "fuel supplier" ARB ID from the refinery. This ensures that the covered refinery emissions are reported and verified

separately from the fuel supplier emissions. It also clarifies verification requirements by requiring verifiers to consider the refinery emissions separately from the supplier emissions, thereby facilitating an effective verification of the refinery emissions.

Hydrogen Fuel Cells: The past few years has seen a growth in installation of new hydrogen fuel cell units. To support the state wide inventory of electricity generation emissions and to help ARB monitor the growth in hydrogen fuel cell installations, emissions reporting for hydrogen fuel cell are added. Fuel cell emissions are still exempted from the Cap-and-Trade program.

Hydrogen Production: Staff is also proposing several new requirements for hydrogen production facilities. The source category description has been edited to include facilities which do not sell hydrogen, but rather consume all the hydrogen they produce on-site (e.g., R&D facilities). To support both the GHG statewide inventory, new requirements have been added which require reporting of carbon and hydrogen content and CH_4 and N_2O combustion emissions. Reporters will also be required to report the amount of on-purpose and by-product hydrogen production at their facility. Reporters will need to include their flaring emissions, a requirement that was originally in the 2007 version of the reporting regulation, but was inadvertently omitted during the harmonization with the U.S. EPA rule in 2010. Finally, reporters will be required to adjust their facility emissions for both transferred CO_2 to guard against double-counting and provide data consistency for all report facilities. These updates support the development of an accurate GHG inventory and support benchmarking and allocation analyses in the Cap-and-Trade program.

Stationary Combustion Sources: Staff revised this section to simplify emissions estimation for biomass-derived fuel, allowing use of the Tier 1 or Tier 2 methodologies when biomass fuels are mixed with fossil fuels. Staff also provided a correction for the aggregated data reporting requirement, so fuel use percentages are reported instead of heat input values, which is consistent with the reporting tool inputs. Staff also added new product data reporting requirements for several industrial sectors. This additional reporting is needed for Cap-and-Trade benchmarking and allocation of free allowances to the affected sectors.

Lime Production Emissions: For some industrial sectors that produce lime, the CO_2 produced is reabsorbed into the manufacturing process and not released into the atmosphere. Staff has proposed an updated emissions estimation method that accounts for CO_2 reinjected and recovered in production, so emissions can be treated appropriately in the Cap-and-Trade program.

Fuel Suppliers: Several revisions have been added for suppliers of transportation fuels, natural gas, natural gas liquids, and liquefied natural gas (LNG). The first allows all fuel suppliers to use *de minimis* provisions in reporting. This ensures consistency with other

reporting entities, which already are allowed to use *de minimis* provisions. For transportation fuel suppliers, staff added language to delineate which fuels are required to be reported. Specifically, the new language clarifies that fuel used for aviation or marine purposes is not reported as a transportation fuel, primarily because the fuel is largely combusted outside of California.

In addition, staff also revised the definition and reporting requirements for operators of intrastate pipelines to better clarify the applicability and reporting requirements for operators of intrastate pipelines delivering natural gas. This addition was made to ensure consistent and complete reporting of all natural gas delivered to end-users within California. New provisions affecting natural gas utilities were also added, which require utilities to report customer data regarding deliveries to smaller end-users and 're-deliveries' to other natural gas utilities. The new reporting requirements will enhance ARB staff's ability to accurately and promptly determine the covered emissions value for the natural gas utilities.

Lastly, additions were made to the applicability requirements and reporting requirements that require all liquefied natural gas production facilities to quantify and report emissions from delivered LNG product if the facility is receiving the natural gas feedstock for the liquefaction process from an interstate pipeline. This addition ensures that there are no gaps in reporting natural gas supplied in California.

Petroleum and Natural Gas Systems: The majority of the proposed changes to Subarticle 5 will correct clerical references, address equation variable omissions, and provide additional clarity. The definition of an onshore petroleum and natural gas production facility was clarified to support the allocation of allowances in the Cap-and-Trade program. Additional edits provide clarity to the reporting of stationary combustion emissions, particularly combustion emissions associated with non-pipeline quality natural gas. Staff has also proposed new language to require reporting of emissions from completions and workovers from oil wells in addition to current requirements for gas wells. This will result in more complete emissions coverage as the majority of wells in California are for oil production.

Staff has proposed revisions to add flexibility in leaker emission reporting by allowing the use of both the population counts and the sampling method for estimating emissions. This will result in an annual cost savings of $1,125,000 while maintaining the reporting of this data. Since leaks are fugitive emissions, they do not carry a compliance obligation in the Cap-and-Trade program.

Staff has also added new language to require that the amount of dry gas produced is also reported. While this was optional in prior data years, it is now required to support Cap-and-Trade allowance allocations. Other new language requires the reporting of the crude fraction and associated gas fraction of emulsion piped as an emulsion as defined in section 95102(a), also to support Cap-and-Trade allowance allocation. Finally, staff proposed that onshore natural gas processing facilities with an annual throughput of 25MMscf/day or more are required to report volumes of gas processed.

Flash Liberation Test: ARB staff has proposed to add in a new test procedure, which details an ARB methodology for the testing and determination of produced water, crude oil and condensate emissions via a flash liberation test. This procedure is a cost-effective method of determining gas-to-oil and gas-to-water ratios for oil wells. The test procedure is included in new Appendix B of this regulation.

Verification: Several provisions related to verification services and verification bodies have been updated. New language clarifies specific requirements for the conformance evaluation. Staff is also proposing updates to allow for multiple product data verification statements in cases where multiple product types are reported (e.g., primary refinery products and carbon dioxide weighted tonne). Staff has also added language to clarify the intent of the correctable error requirements in section 95131(b)(9).

Staff added language to clarify requirements of liability insurance for verification bodies, as well as simplifying the withdrawal requirements for verification bodies who no longer wish to participate in the mandatory reporting program. Clarifying language allows verification bodies to perform multiple third-party verification services for the same reporting entity under the auspices of different GHG reporting programs, and avoid a high conflict determination, provided that the verification body continues to observe the requirements of mandatory reporting conflict of interest (COI) determination.

General: Staff has proposed modifications in a number of other sections, in order to maintain consistency in the structure of the regulation. None of these minor modifications are intended to alter requirements – several of the updates or additions correct clerical oversights and references, while others renumber sections for uniformity with the remainder of the reporting regulation.

C. RATIONALE SUPPORTING THE PROPOSED SOLUTIONS

As stated previously, the amendments are being made to ensure the most accurate GHG data is reported and verified to support the Cap-and-Trade program, and ARB's GHG emissions inventory. Anticipated benefits of the proposed amendments include improved clarity for reporting entities as to their reporting and verification obligations, more accurate GHG emissions estimates from corrected or updated emissions calculation methods and emission factors, improved clarity to support the statewide greenhouse inventory program and continued robust methods for reporting emissions and product data in order to support ARB's Cap-and-Trade program and other GHG-related programs. These benefits may also have indirect beneficial impacts on the health and welfare of California residents, worker safety, and the state's environment by ensuring that the state has an accurate emissions inventory to support ARB's emission reduction measures.

D. ALTERNATIVES CONSIDERED

California Government Code section 11346.2 requires ARB to consider and evaluate reasonable alternatives to the proposed regulatory action and provide reasons for rejecting those alternatives. This section discusses alternatives evaluated and provides reasons why these alternatives were not included in the proposed revised regulation. ARB staff did not find any of the alternatives considered to be more effective in carrying out the purpose for which the revised regulation is proposed, or to be as effective or less burdensome to affected businesses, than the proposed revised regulation.

Take No Action Alternative for Complete Regulation. An overall "no action" alternative means that no revisions would be made to the existing California GHG reporting regulation. Under this alternative, ARB and reporting entities would continue to operate pursuant to the requirements of the existing regulation. If ARB were to take no action, reporting entities subject to the existing GHG regulation would prepare California-specific emissions data reports which are not fully supportive of ARB GHG inventory and Cap-and-Trade programs. In addition, without action, the clarifications and updates proposed would not be implemented, leading to incomplete and potentially incorrect data reporting. For these reasons, the take no action alternative is neither practical nor beneficial to ARB and its affected reporters.

The following sections provide additional discussion of alternatives considered for proposed changes that may lead to additional requirements or costs for reporters.

Additional Qualitative Data Collection Requirements. Staff has proposed requirements to include additional descriptive and qualitative information that has a minimal impact on reporters or costs, but which significantly improve the usefulness of collected data. This primarily includes information from abbreviated reporters, power generators, fuel suppliers, and cogeneration plants. Two alternatives were considered in making these revisions. The first was to not collect the additional data (no action alternative). This alternative would reduce the utility of data being collected and needed for Cap-and-Trade and GHG inventory analysis purposes. The second alternative considered was to collect the data from other sources. This alternative would require contacting affected facilities, air districts, or other data sources individually which would be extremely resource intensive for both the ARB and for the reporting entities. Instead, the most efficient and cost effective approach is to update the regulation as proposed, and require reporting of the additional information via the existing GHG mandatory reporting regulation, through the existing ARB greenhouse gas reporting tool. Therefore, neither of these alternatives considered by the agency would be more effective in carrying out the purpose for which the revisions are proposed or would be as effective or less burdensome to affected private persons than the proposed revisions.

Requirements for Specified Source and Asset-Controlling Supplier requirements, and System Power Reporting. Staff has proposed several modifications to the requirements necessary to claim specified source power, Asset-Controlling Supplier power, and power tagged at the system level (system power). Additional changes would clarify language on the ownership threshold for retail provider reporting emissions associated

with High GHG-Emitting Facilities or Units located outside California, and on the retention of generation meter data.

These amendments clarify the reporting requirements. Sellers of specified power would be required to warrant or guarantee that power sold was actually acquired as specified source power, and is not re-marketed unspecified power. Electric power entities would be required to submit supporting documentation for specified source busbar claims that do not use the transmission loss factor, to provide a more specific verification standard. The amendments would also require reporters of Asset-Controlling Supplier (ACS) power to report as unspecified, when not acquired as specified source power, in order to reflect the fact that Asset-Controlling Supplier power can be sold in the market as either specified or unspecified power; require reporters to use the transmission loss factor when reporting Asset-Controlling Supplier power, in order to reflect actual transmission loss associated with delivery from the Asset-Controlling Supplier system to California; and would require purchasers of system power with a carbon content above the default emission factor to report using a system power emission factor rate to be determined by ARB, instead of at the unspecified rate, in order to reflect system power carbon content.

In evaluating amendments for this sector, two alternatives were evaluated including to take no action (retaining the existing requirements) or to harmonize with U.S. EPA requirements. In the current reporting regulation, certain provisions for specified source power and Asset-Controlling Supplier power claims are ambiguous, and there are currently no provisions in the reporting regulation for system power tagged. Without the proposed changes, to obtain the necessary data, ARB would have to provide guidance that might potentially extend beyond the explicit authority provided in the regulation. The proposed update avoids this possibility. Second, the U.S. EPA GHG reporting rule does not address electricity power imports nor provide for any designation of asset-controlling supplier; therefore the data must be collected via the reporting regulation under the proposed revisions. Therefore, neither of these alternatives considered by the agency would be more effective in carrying out the purpose for which the revisions are proposed or would be as effective or less burdensome to affected private persons than the proposed regulation.

Requirements for Petroleum Refineries and Hydrogen Production. Under the proposed revisions, refineries that are also fuel suppliers would be required to separately report these activities as separate reporting entities. This provides additional clarity desired by both ARB and the regulated reporting entities. For hydrogen production, the changes eliminate potential double counting of emissions, and include additional requirements to ensure consistent and complete data reporting. For both of these sectors, the two alternatives considered were taking no action and directly adopting the associated U.S. EPA regulations. Not taking action would provide incomplete and potentially inaccurate data reporting. Adopting the associated U.S. EPA requirements is an inadequate alternative because the data collected would not be sufficiently accurate or complete to meet ARB program needs. Therefore, neither of these alternatives considered by the agency would be more effective in carrying out the purpose for which the revisions are

proposed or would be as effective or less burdensome to affected private persons than the proposed revisions.

Requirements for Petroleum and Natural Gas Systems. The proposed changes for this sector were included to require reporting of emissions from completions and workovers for oil wells for more consistent and complete reporting, to clarify reporting requirements for an onshore oil and gas production facilities, and to correct typos and add clarifying text. The two alternatives considered were taking no action and directly adopting the associated U.S. EPA regulations. Not taking action would provide incomplete and potentially inaccurate data reporting. Adopting the associated U.S. EPA requirements is an inadequate alternative because the data collected would not be sufficiently accurate or complete to meet ARB program needs, including Cap-and-Trade. Therefore, neither of these alternatives considered by the agency would be more effective in carrying out the purpose for which the revisions are proposed or would be as effective or less burdensome to affected private persons than the proposed revisions.

Addition of Reporting Requirements for Lead Production. The proposed revision includes the addition of reporting requirements for the lead production sector, which was overlooked in the previous regulation. Two alternatives were considered to this proposal, which were taking no action and directly adopting the associated U.S. EPA regulations for lead production. Not taking action would provide incomplete reporting, and would not be equitable when compared to other facilities that must submit GHG data reports. Adopting the associated U.S. EPA requirements is an inadequate alternative because the data collected on its own would not be sufficiently accurate or complete to meet ARB program needs. Therefore, neither of these alternatives considered by the agency would be more effective in carrying out the purpose for which the revisions are is proposed or would be as effective or less burdensome to affected private persons than the proposed revisions.

Requirements for Verification. The proposed revisions for the verification requirements are included to clarify the verification requirements, and to improve the overall completeness of the verification process. The only alternative considered related to these proposed revisions was to take no action. Taking no action would produce detrimental impacts on the full verification of submitted data reports. Verification is a primary element in ensuring complete and accurate reporting, so deficiencies in the verification process produces deficiencies in data used by ARB programs that rely on the verified data. Therefore, no alternative considered by the agency would be more effective in carrying out the purpose for which the revisions are proposed or would be as effective as or less burdensome to affected private persons than the proposed revisions.

III. SUMMARY OF PROPOSED ACTION

Staff is proposing the amendments to the reporting regulation to continue to support the Cap-and-Trade program through the reporting of complete and robust GHG emissions data, and to continue supporting the statewide GHG emissions inventory, to the extent

feasible. A more detailed summary of the proposed amendments is included in Section B of Chapter II (Proposed Solutions to the Problem). Staff is recommending that the Board accept the revisions to the regulation, as proposed.

IV. ENVIRONMENTAL IMPACTS ANALYSIS/ASSESSMENT [CEQA Analysis]

A. Introduction

This chapter provides an environmental analysis (EA) for the proposed regulatory amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. Based on ARB's review, staff has determined that the implementations of the proposed amendments would not result in any significant or potentially significant adverse impacts on the environment. This analysis provides the basis for reaching this conclusion. This section of the staff report also discusses the environmental benefits resulting from the implementation of the proposed regulatory amendments.

B. Environmental Review Process

ARB is the lead agency for the proposed regulatory amendments and has prepared this EA pursuant to its regulatory program certified by the Secretary of the Natural Resources Agency (14 CCR 15251(d); 17 CCR 60005-60007). In accordance with Public Resources Code section 21080.5 of the California Environmental Quality Act (CEQA), public agencies with certified regulatory programs are exempt from the requirements for preparing environmental impact reports, negative declarations, and initial studies (14 CCR 15250). As required by ARB's certified regulatory program and the policy and substantive requirements of CEQA, ARB has prepared an assessment of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulation and a succinct analysis of those impacts (17 CCR 60005(b)). This EA is included in the Staff Report: Initial Statement of Reasons (ISOR) prepared for the rulemaking (17 CCR 60005). The resource areas from the CEQA Guidelines Environmental Checklist were used as a framework for assessing the potential for significant impacts (17CCR 60005(b)).

If comments received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in writing. The written responses will be included in the Final Statement of Reasons (FSOR) for the regulation. If the regulation is adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection (17 CCR 60007(b)).

C. Prior Environmental Analysis

The Regulation for the Mandatory Reporting of Greenhouse Gas Emissions was originally developed pursuant to the California Global Warming Solutions Act of 2006 (AB 32), and became effective on January 1, 2009 (ARB MRR 2007). In 2010, ARB proposed additional revisions in order to support a California greenhouse gas (GHG) Cap-and-Trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements contained in Title

40, Code of Federal Regulations, Part 98, and became effective on January 1, 2012. In 2012, ARB proposed further revisions in order to continue supporting Cap-and-Trade, as well as the AB 32 Cost of Implementation Fee regulation, and continued harmonization with U.S. EPA updates, which became effective on January 1, 2013. The environmental analyses in the prior Staff Reports for the initial regulation, and its 2010 and 2012 revisions concluded that the regulation would not result in any significant environmental impacts.

D. Proposed Amendments

1. Description

   The proposed regulatory amendments are described in detail in Chapter VII of this Staff Report. These changes clarify and amend existing requirements and definitions in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

2. Methods of Compliance

   In order to comply with the proposed amendments, the regulated community would collect and submit the required data in the required timeframe, as required by the regulation.

E. Environmental Impacts/ Assessment

Based on ARB's review of the proposed regulatory amendments, staff concludes that the amendments would not result in any significant or potentially significant adverse impacts on the environment because compliance with the proposed amendments would not result in any physical change to the existing environment. The amendments consist of administrative and procedural changes that affect only program administration and contents of databases, and do not involve or result in any new development, modifications to buildings, or new land use designations. Further, compliance with the proposed amendments would not involve any activity that would involve or affect aesthetics, air quality, agricultural and forestry resources, biological resources, cultural resources, geology and soils, greenhouse gases, hazardous material, hydrology and water quality, land use planning, mineral resources, noise, population and housing, public services, recreation, or traffic and transportation because they would not require any action that could affect these resources.

No discussion of alternatives or mitigation measures is necessary because no significant or potentially significant adverse environmental impacts were identified.

V. ENVIRONMENTAL JUSTICE

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies (Senate Bill 115, Solis; Stats 1999, Ch. 690; Government Code § 65040.12(c)). The Board approved Environmental Justice Policies and Actions on December 13, 2001, to establish a framework for incorporating environmental justice into the ARB's programs consistent

with the directives of State law. The policies subsequently developed apply to all communities in California, but they recognize that environmental justice issues have been raised more in the context of low income and minority communities, which sometimes experience higher exposures to some pollutants as a result of their proximity to multiple sources of air pollutants.

Actions of the ARB, local air districts, and federal air pollution control programs have made substantial progress towards improving the air quality in California. However, some communities continue to experience higher exposures than others because of the cumulative impacts of air pollution from multiple sources.

Adoption and implementation of the proposed amendments to the reporting regulation will have no negative environmental impacts on environmental justice communities. Facilities throughout the state will be required to report their GHG emissions, with the focus on those facilities producing the highest levels of emissions. The amended regulations continues to include mandatory reporting for over 90 percent of the stationary source GHG emissions in California, including specified combustion, process, and fugitive emissions. Emissions information from these reports will be made available to the public.

VI. ECONOMIC IMPACTS

The economic impacts analysis shown in this staff report was conducted to meet current legal requirements under the Administrative Procedure Act (APA). Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies shall assess the potential for adverse economic impact on California business enterprises and individuals. The assessment shall include a consideration of the impact of the proposed or amended regulation on the ability of California businesses to compete with businesses in other states, the impact on California jobs, and the impact on California business expansion, elimination, or creation.

In this chapter, ARB staff provides the estimated costs to businesses and public agencies to comply with staff's proposed amendments to the reporting regulation. The amendments are expected to affect approximately 170 private business entities, 21 local government entities, and 6 state government entities. The proposed amendments are expected to impact 274 facilities (including those operated by private and public entities) and 11 fuel supplier entities, for a total of 285 reporting accounts. There is a difference between the number of business entities and the number of reporting accounts because the point of regulation is an individual facility (where the facility, not its parent company, is the regulated unit), and many facilities have common parent company or common operator. On the other hand, under the reporting requirements, a fuel supplier company reports all applicable activities in the state, regardless of the physical locations where the activities occur. Therefore, instead of its individual activity locations, a fuel supplier company is the regulated unit in the GHG reporting program. The total cost impact to all affected entities, including private businesses and local and state government entities, is projected to be $56 million over an 8-year time period.

The cost estimates are based on approximations of the amount of time required to comply with the amended provisions, associated labor wage rates, costs of any emissions measurement requirements, and verification costs. The approximations of costs provide a general picture of the economic impacts that typical businesses subject to the proposed amendments might encounter. ARB staff recognizes that individual companies may experience different impacts than those projected here, depending on various factors such as complexity of operation, types of emission units on-site, and existing compliance practices.

Overall, most affected businesses are among the larger businesses in California. ARB staff does not expect these businesses to be affected adversely by the costs of the proposed amendments. As a result, staff does not expect a noticeable change in employment, business creation, expansion, or elimination, or business competitiveness in California. However, staff anticipates that existing contractors that perform work for the oil and gas sector may need to expand to meet additional needs, and existing consulting businesses that assist regulated entities with emissions reporting and verification may see new business opportunities as the result of the proposed amendments.

A. Analysis of Costs and Economic Impacts

A.1. Summary of Costs and Economic Impacts

There are three primary costs associated with complying with the proposed amendments to the reporting regulation:

1. Emission reporting compliance costs, including costs incurred for monitoring, sampling, recordkeeping activities and the preparation of an annual emissions data report;
2. Costs for third-party verification of submitted GHG emissions data, when required; and
3. Costs to the State to administer the reporting program, including modifying the existing web-based reporting tool and data system to incorporate the proposed amendments.

In developing the amendments to the GHG reporting regulation, staff has attempted to minimize costs, while complying with the specific reporting requirements of AB 32 and collecting data of high quality to support the market-based Cap-and-Trade program. The amended regulation will have noticeable cost impacts on half of all the businesses currently subject to the existing reporting regulation. Other businesses that are already subject to the reporting regulation will not experience a noticeable change in cost of compliance.

Over 8 years, ARB staff estimates that the amended requirements will lead to a cost increase of $56 million for private business entities, $54,600 for local government entities, and $13,900 for state government entities. For an average private business entity not in the oil and gas sector, the amendments are expected to result in an average annual cost increase of approximately $4,200 in the initial year and $2,800 in the ongoing years per business entity (which may operate multiple facilities, each of

which may be impacted by the regulation amendments differently). An oil and gas company may see an average incremental cost of approximately $479,000 in the initial year and ongoing years. Staff estimated that 98.1% of all the cost impacts occur in the oil and gas sector.

For the 21 affected local government entities, the amendments are expected to result in an average annual cost increase of $1,150 in the initial year and $250 in the ongoing years per local government entity (which may operate multiple facilities, each of which may be impacted by the regulation amendments differently). For the 6 affected state universities and state prison, the amendments are expected to result in an average annual cost increase of $1,005 in the initial year and $230 in the ongoing years per state government entity.

For all regulated entities, staff anticipates costs to diminish over time as facilities and fuel suppliers incorporate GHG reporting into their normal business practices. Summaries of state-wide incremental costs are presented in Table VI-1a, Table VI-1b, and Figure VI-1. All costs are stated in 2012 dollars. Although a range of conservatively high and conservatively low costs were estimated, the tables and figure show only the middle-estimate values.

Table VI-1a. Summary of Incremental Costs for Private Businesses

Industry Sector	Number of Affected Companies[1]	Number of Affected Reporting Entities[1]	8-Year Cost ($)[2]	Share of Total Private Industry Cost
Oil & Gas Production	17	27	55,138,715	98.11%
Petroleum Refineries	9	14	277,416	0.49%
Food Manufacturing	33	58	259,451	0.46%
General Stationary Fuel Combustion Facilities	59	76	207,554	0.37%
Power Generation	35	55	107,179	0.19%
Hydrogen Production	3	7	89,077	0.16%
Lead Production	1	1	81,958	0.15%
Lime Manufacturing	1	1	20,094	0.04%
Fuel Supplier	11	11	17,574	0.03%
Glass Production	1	1	1,983	0.0035%
TOTAL	**170**	**251**	**56,201,001**	**100%**

[1] As defined in the GHG reporting regulation, a reporting entity is a facility, a supplier of fuel or CO_2, or an electric power entity. A business or a company may operate multiple facilities (and therefore multiple reporting entities) that are each subject to the reporting regulation and may each be impacted by the amendments differently. For the operator of industrial facilities, the point of regulation or the regulated unit is a facility, not its company.

[2] Future costs are discounted at 5%. A time horizon of 8 years is used for the regulation implementation from 2014 to 2021. Although a range of conservatively high and conservatively low costs were estimated, the table only shows the middle-estimate values.

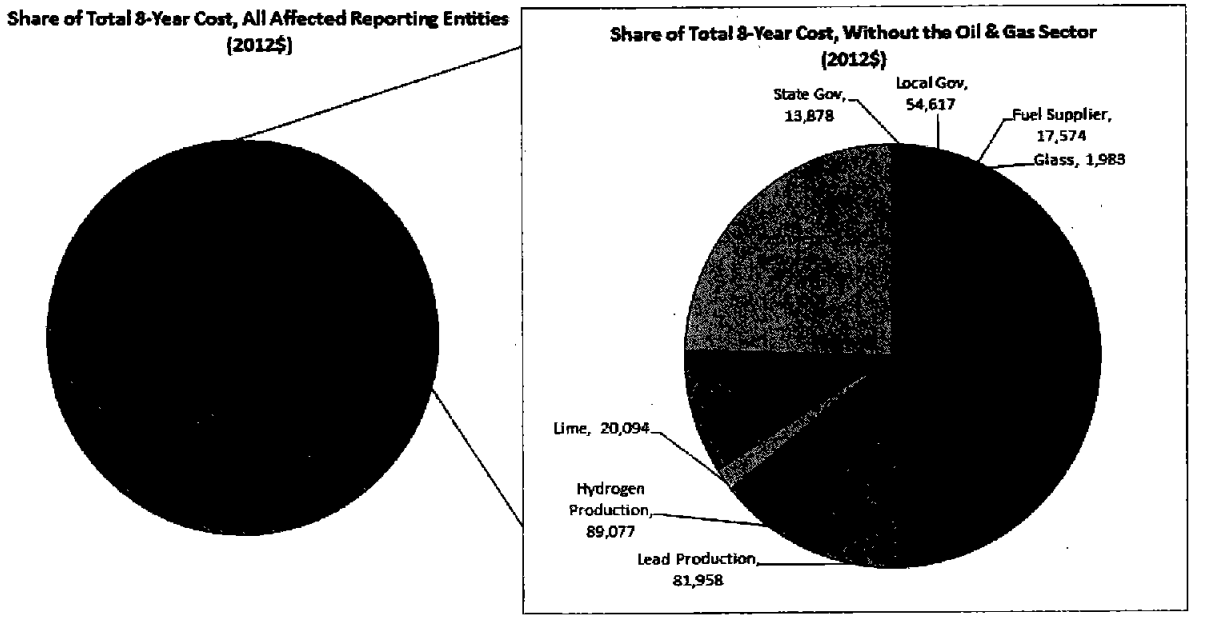
Table VI-1b. Summary of Incremental Costs for Government Entities

	Number of Affected Government Entities[1]	Number of Affected Reporting Entities[1]	8-Year Cost ($)[2]	Average 8-Year Cost/ Entity ($)
Local Government Entities	21	28	54,617	2,601
State Government Entities	6	6	13,878	2,313

[1] As defined in the GHG reporting regulation, a reporting entity is a facility, a supplier of fuel or CO_2, or an electric power entity. A government entity may operate multiple facilities (and therefore multiple reporting entities) that are each subject to the reporting regulation and may each be impacted by the amendments differently. For the operator of industrial facilities, the point of regulation or the regulated unit is a facility, not its company.

[2] Future costs are discounted at 5%. A time horizon of 8 years is used for the regulation implementation from 2014 to 2021. Although a range of conservatively high and conservatively low costs were estimated, the table only shows the middle-estimate values.

Figure VI-1. Total 8-Year Cost among Private Industry Sectors and Local and State Government Entities



The proposed amendments will not require additional ARB funding. The amendments will be implemented using existing ARB staffing. Any ARB fiscal expenses needed for

implementing the proposed amendments are already accounted for in the current operational budget that was approved as a part of the previous rule amendments.

None of the businesses affected by these proposed amendments are small business entities and in most cases, have millions of dollars in annual revenues. The cost of this amendment is not expected to have a significant material impact on these businesses. As a result, ARB staff does not expect a noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due the reporting requirements. ARB staff also expects no job or business losses due to the reporting regulation since most of the job creation associated with GHG reporting was gained following implementation of the original rule in 2007. Although it is not quantified, existing contractors that perform work for the oil and gas sector may expand to meet additional needs, and existing consulting businesses that assist regulated entities with emissions reporting and verification may see new business opportunities as a result of the proposed amendments.

Although the economic impacts of these amendments are not expected to have a direct impact on the health and welfare of California residents, worker safety, and the state's environment, the anticipated benefits of the amendments described in Chapter II may have indirect benefits on the health and welfare of California residents, on worker safety, and on the state's environment.

The information, assumptions and methodologies used to determine compliance costs are summarized in Section A.3 of this chapter. All the cost estimates provided in this chapter are given in 2012 dollars.

A.2. Legal Requirements for Fiscal Analysis

Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies must assess the potential for adverse economic impacts on California business enterprises and individuals, including the ability of California businesses to compete with businesses in other states. The assessment must also include the potential impact of the regulation on California jobs, business expansion, elimination or creation, and the ability of California business to compete with businesses in other states.

Also, State agencies are required to estimate the costs or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies, and the cost or savings in federal funding to the State.

Health and Safety Code section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to the proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. ARB staff has determined that the amendments to the proposed regulations are not a major regulation as defined above.

The following is a description of the methodology used to estimate costs, as well as ARB staff's analysis of the economic impact on California businesses and State and local agencies.

A.3. Analysis of Estimated Costs for Compliance

As a part of developing the regulatory amendments, ARB staff estimated the costs of compliance for facilities subject to the amendments. Briefly, the steps taken to estimate costs for facilities and entities are as follows:

- Review individual amended requirements to identify those that may have noticeable cost impact on affected reporting entities.
- Establish the baseline for the cost estimation, which is the cost of compliance to meet the requirements of the extant regulations.
- Identify the new tasks that each facility type will need to perform to comply with the amended regulation, as well as the existing tasks that each facility type will no longer need to perform.
- Evaluate the incremental costs associated with the changes in tasks that are expected to be performed by the reporting entities in monitoring and sampling fuel, measuring emissions, preparing emissions reports, creating or updating GHG monitoring plans, developing GHG emission estimates, and providing staff to prepare and submit the emissions reports as well as hosting verification site visits. The labor costs are calculated by multiplying the estimated time requirements for performing each task by a range of wage rates from the U.S. Bureau of Labor Statistics (BLS 2012).
- Estimate the costs of third-party verification for facilities that will be newly subject to verification after the promulgation of the amended regulation, and for facilities that are already subject to verification but are likely to see an incremental increase in verification costs due to the new data resulted from the proposed monitoring, measurement, and reporting requirements.
- Compile all the cost components and calculate the cost impacts for each amended requirement that has been identified to lead to a noticeable cost impact.
- Review the list of reporting entities (facilities and fuel suppliers) and the information they included in their emissions data reports to identify the reporting entities affected by each amended requirement.
- Group the affected reporting entities identified in the previous step by their parent company, and count the number of affected "businesses" or "companies" (the unit of economic impact evaluation mandated by State Administrative Manual Sections 6600 – 6680; note that this unit of economic impact is different from the point of regulation or the regulated unit under the reporting regulation).
- Sort the affected reporting entities into industry sector categories. Sum all the estimated costs to industry sector category level. Calculate the average cost per

company by dividing the sum of the industry sector cost by the number of affected companies in the sector.

- Review the information submitted in the emission data report and research the ownership structure to identify any small business entities.
- Review the list of affected facilities to identify those owned by local and state government entities. Group these facilities by their common local government entity owner. Quantify costs similar to private industry sector described above.
- Calculate the total costs over 8 years by applying a discount rate of 5%.

The methodology for estimating incremental costs is described in the following subsections.

A.3.1. Scope of Cost Estimation

Baseline and Incremental Cost

This analysis focuses on the net difference (or increment) between two cost estimates:

- baseline compliance costs for GHG reporting under extant regulations, and
- additional compliance cost or saving under the proposed amendments.

The incremental costs or saving estimated in this analysis do not represent the total costs to comply with GHG reporting regulations, but only the difference between the cost of GHG reporting with and without the proposed amendments. The net incremental cost combines both cost increases and cost savings.

Amended Rule Provisions with Noticeable Change in Costs

Many of the amended regulatory provisions provide clarifications to the existing requirements and do not lead to a change in cost; while some amended provisions instruct reporting entities to include in their emissions data report some information they already know and do not require additional time to measure or collect, and these also do not lead to a noticeable cost increase. Staff identified 15 proposed regulatory provisions that may lead to a noticeable change in costs. ARB staff has estimated the economic impacts for each of these provisions in this economic analysis:

- Abbreviated reporters to report breakout of aggregated fuel consumption by unit type categories. Engineering estimation is acceptable and no new meter installation is required.
- Facilities with purchases of biomethane to report additional information on the biomethane source.
- Facilities with total facility emissions greater than 25,000 $MTCO_2e$ but which have less than 25,000 $MTCO_2e$ of cap-and-trade covered emissions are to prepare

and maintain a GHG monitoring plan consistent with other facilities.

- Operators of hydrogen fuel cells are to calculate and report emissions from hydrogen fuel cell units to include in the applicability threshold comparison.
- Operators that use cogenerated energy in chillers that produce cooling to an outside end-user or on-site industrial process must report the amount of steam used for these applications.
- Refineries that are also subject to reporting requirements as a fuel supplier are to report their refinery operation and fuel supply operation in separate emission data reports.
- Hydrogen production facility operators are to determine the carbon and hydrogen content of feedstock, report CH_4 and N_2O emissions, and report flaring emissions and hydrogen sales data.
- A lead production facility operator is newly subject to the reporting program in California.
- A lime manufacturing facility is to measure and account for the process CO_2 emissions recaptured and not emitted to the atmosphere.
- Local Distribution Companies (LDC) are to report the annual gas quantity, customer information, and ARB ID (if available) for all deliveries to end-users registering greater than 188,500 MMBtu, effectively lowering the threshold for reporting end-user information from 25,000 MT CO_2e of gas delivered to 10,000 metric tons CO_2e of gas delivered.
- Liquefied natural gas (LNG) production facility operators are to quantify and report emissions from delivered LNG product if the facility is receiving the natural gas feedstock for the liquefaction process from an interstate pipeline.
- Operators of facilities in industry sectors that receive new transition assistance based on product-based benchmark are to report new covered product data.
- Onshore oil and gas processing facilities which pipe emulsion from an oil platform as defined in the reporting regulation.
- Onshore oil and gas production facility operators are allowed to use either the population count method or the sampling method for estimating emissions leaks (this results in a cost saving).
- Onshore oil and gas production facility operators are to measure and report well completion and workover emissions from all oil wells in addition to gas wells.

Identification of Affected Facilities, Entities, and Companies

For industrial and institutional facilities and power plants, the rule applicability of the reporting regulation is determined on a facility basis, and the rule provisions are also implemented on a facility basis. An individual facility, rather than its parent company, is the "point of regulation" or the regulated unit. A separate emissions data report must be submitted for each facility. Facilities operated by local and state government entities

are treated the same as facilities operated by private businesses. On the other hand, the reporting boundary and regulation applicability for fuel suppliers and electric utilities is determined on a company basis in the reporting regulation. Therefore, the cost analysis for facilities was done on a facility basis that was later reconciled to the company-level, while the cost analysis for fuel supplier was done on a company basis.

At the time of this regulation amendment, the California GHG reporting program has already collected 5 years of data (2008-2012) from individual reporting entities that are subject to the regulation. ARB staff also has acquired substantial knowledge in the practices and operations of reporting entities through years of experience assisting reporters and verifiers during program implementation. Unlike previous regulation amendments, where specific reporting entities affected by the amendments were often unknown, ARB staff was able to identify the specific reporting entities that are expected to be impacted by each amended provision for the current rulemaking. For each of the 15 amended rule provisions with a cost impact, staff used information submitted in the emissions data reports and staff's knowledge about the individual reporting entities in identifying the affected facilities. Staff also anticipated that approximately 4 new facilities may be captured by the proposed addition of hydrogen fuel cell emissions reporting. While the majority of reporting entities were impacted by only one amended provision, some reporting entities may be affected by more than one amended provisions.

Additionally, as previously stated, the State Administrative Manual Sections 6600 – 6680 mandates that state government agencies evaluate economic impacts based on "business" or "company," and this unit of economic impact evaluation is different from the regulated unit of the reporting regulation. Many businesses or companies operate multiple facilities, and each of these facilities may be subject to a different combination of the amended rule provisions. Some businesses/companies have operations that fall under multiple industry sectors. Therefore, additional work is required in order to convert the estimated cost on a facility basis to a company basis.

Staff reviewed each affected facility's parent company information to group them by their parent company. Staff also reviewed each affected facility's emission activities and their reported North America Industrial Classification System (NAICS) codes to sort them into the appropriate industry sector category. A facility that includes operations that fall under multiple industry sectors is assigned to the sector based on its primary NAICS code. Similarly for facilities operated by local and state government entities, staff groups the affected facilities by their common government entity operator.

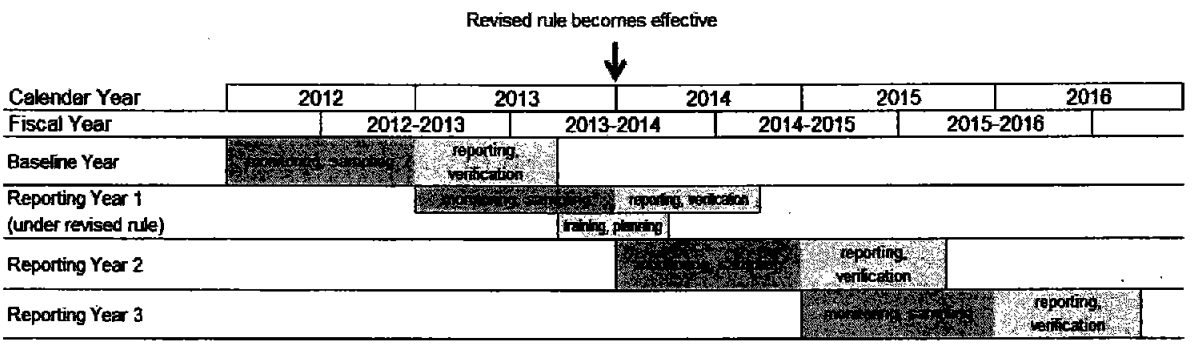
Section A.3.2 describes the methodology that staff employed to estimate the expected incremental costs per reporting account (per "facility" for industrial facilities and power plants, or per company for fuel suppliers) due to each amended rule provision. After summing the incremental costs (from all the amended rule provisions) by industry sector, the average costs per company were calculated by dividing the total sector-wide cost by the estimated number of companies in the sector. Because facilities operated by local and state government entities are treated the same as those owned or operated by private businesses, calculation of costs was done similarly. The cost per entity for local government entities are calculated by summing the incremental costs then divided the sum by the number of entities (not the number of facilities) in the local government

category. Affected state government entities include 5 universities and a state prison, and they are each considered a separate entity.

Annual Cost Summed by Reporting Cycle vs. by Calendar Year

To keep cost accounting on a yearly basis, ARB staff summed the costs by the yearly reporting cycle, which does not coincide with one calendar year. For example, the labor costs for recording fuel use and collecting/analyzing fuel samples are expended during calendar year 1. Labor costs for performing emission calculations, reporting and verification of the year 1 typically occur in calendar year 2. In addition, during calendar year 2, there are new costs for collecting data for the next reporting cycle. Therefore, each calendar year has both cost for the collection of data and the cost for reporting and verification, which makes up the reporting cycle. For purposes of this analysis, each reporting cycle takes into account the collection and reporting and verification costs. Figure VI-2 graphically illustrates the overlap of "reporting year" and "calendar year."

Figure VI-2. Reporting Year and Calendar Year



Time Horizon

A time horizon of 8 years (2014-2021) was chosen for this economic analysis. The year 2014 was chosen as the start of the evaluation period because the amended regulation is proposed to become effective on January 1, 2014. The year 2021 was chosen as the end of the evaluation period because 2020 marks the first major milestone for GHG emission reduction target mandated by AB 32, and the GHG pollutants emitted during calendar year 2020 will be reported and verified in 2021.

A.3.2. Costs of Performing Compliance Tasks

Staff utilized a method similar to an expert elicitation process to estimate the cost components, including labor costs (associated with monitoring, sampling, recording, training, and planning), emissions measurement cost, equipment cost, and verification cost, based on staff's experience in providing support to reporting entities and

verification bodies. The method for estimating each cost component is described below.

Labor Costs

Estimation of Labor Hours

Since the inception of the reporting program in 2008, ARB staff has been working closely with reporting entities in providing technical support for emission calculations, providing training on the rule requirements and the use of the reporting tool, assisting reporters in preparing and submitting electronic emissions data reports, and noting informal feedback from reporters on the time requirements of GHG reporting. ARB staff also works closely with the accredited verifiers to ensure the quality of emissions data reports by observing the on-site practices of reporting entities (observations took place during verification site visits), and collecting informal feedback provided by verifiers and reporters regarding the expenses of GHG reporting and verification. The knowledge gained by ARB staff's direct involvement with reporters and verifiers over the last five years has given staff a clear understanding of the cost and workload associated with implementing this regulation. With this knowledge, staff has estimated the range of costs and hours spent on the following compliance tasks:

- Becoming familiar with rule requirements and the use of the reporting tool, preparing and implementing the GHG monitoring plan, and training facility staff in performing compliance tasks;
- Collecting and analyzing fuel samples, keeping records of fuel analytical data, and calculating emissions at various periodic sampling frequencies;
- Monitoring proper operation of fuel or feedstock measurement equipment and recording consumption data;
- For suppliers of fuels, gathering data required for GHG reporting from their existing database system;
- For oil and gas facilities, complying with the additional monitoring, sampling, testing, and reporting requirements;
- For each applicable sector, performing additional process emissions calculations called for by the respective sections of the proposed amended regulation;
- Entering data, performing quality assurance (QA) checks, and certifying and submitting emissions data report in the reporting tool;
- Coordinating, preparing records for, and hosting verification site visits; and
- Following-up on verification and revising the GHG emissions data report as needed.

ARB staff estimated the incremental time requirements of different compliance tasks that are expected for each amended rule provision. For each provision, a facility may be expected to see only 1 to 4 incremental tasks listed above as a result of the

amendments, even though they may already be performing most of these tasks under the existing regulations.

Cost of Reporting

For the purpose of satisfying the requirements in Section 11346.3 of the Government Code, ARB staff has assessed the labor costs related to reporting emission data ("cost of reporting") as consisting of the costs associated with recordkeeping, submitting data through the web-based reporting tool system, and certifying and submitting the report. These compliances tasks associated with "cost of reporting" consist of a subset of the total reporting costs. Costs for training and planning, fuel sampling and testing, emission monitoring, emission calculation, and third-party verification are not included in the "cost of reporting." "Cost of reporting" and other labor costs are all estimated using the methodology described in this subsection.

It was determined that the amended provision of "allowing onshore oil and gas production facility to use the population count method for estimating emissions leaks" does not result in an incremental change in "cost of reporting," while the other 14 amended rule provisions may lead to a marginal increase in "cost of reporting." Staff estimated the labor costs associated those compliance tasks at a per-facility level for each amended rule provision. The "cost of reporting" per facility is then multiplied by the number of facilities that are impacted by the amended rule provision. The average "cost of reporting" per company is obtained by dividing the total "cost of reporting" by the total number of companies impacted by the rule provision. The total "cost of reporting" for California businesses is estimated to be $69,794 (mid-estimate), and the average "cost of reporting" per company is $411 ($69,794/170 companies).

Table VI-2 summarizes the estimated "cost of reporting" per facility (or per GHG account) in the ongoing years.

Table VI-2. Cost of Reporting

Amended Rule Provision	No. of Private Facilities or Reporting Accounts Affected	Incremental Reporting Cost per Reporting Account ($)
Abbreviated reporter to report fuel use by unit type	86	194
Report biomethane producer information	1	50
GHG monitoring plant for all facilities with >25K of emissions	50	108
Inclusion of hydrogen fuel cell emissions	8	150
Report cogenerated steam used in producing cooling energy	2	397
Separate reports for refineries and fuel suppliers	5	690
Hydrogen production facility to report additional information	20	187
Add reporting of lead production	1	1,117
Lime manufacturing- quantify process CO_2 recaptured	1	172
LDC fuel suppliers report additional customer data	7	203
LNG data reporting if interstate pipeline gas is used	1	380
Report additional covered product data	39	250
Reporting of emulsion from an oil platform	1	709
Onshore oil & gas- new requirement on oil well venting	24	1,037

Reporting Entity Staff's Time in Support of Verification

ARB staff developed time requirement estimates for a facility preparing and hosting the verification site visit. Staff anticipates that some facilities may become newly subject to verification requirements due to the following proposed amendments: inclusion of hydrogen fuel cell emissions, adding reporting of lead production facility, reporting LNG data if interstate pipeline gas is used, and reporting emulsion from an oil platform.

Staff identified the individual tasks associated with verification that facility and fuel supplier staff is expected to do. These tasks may include identifying and acquiring verifier, reviewing the contract, setting up and coordinating a verification site visit, preparing records for verifier review, participating in verification site-visits, and revising emissions data reports after verification. The total labor costs for performing each compliance task were estimated by multiplying the estimated time requirement of the task by a range of wage rates (in $/hour) for the type of facility staff that typically performs the task. Labor costs are estimated for each of the 4 amended regulatory provisions.

For other amended provisions that may increase the amount of time spent by verifiers in data review, but are not likely to lead to a noticeable difference in the amount of time that reporting entity staff may spend on preparing and hosting verification, ARB staff

assumes that the difference in time requirement is negligible and did not separately estimate those labor costs. However, the cost for additional time spent by the verifier is estimated and described in the Cost of Third-Party Verification Service sub-section.

Wage Rate by Staff Class

ARB staff assigned each individual task to a corresponding staff classification. Staff classifications include administrative staff, technical staff, managerial staff, and lawyers. The technical staff classification is further divided: 1) technical staff 1 may include junior engineers, scientists, senior operators, and senior technicians; and 2) technical staff 2 may include mid- to senior- level engineers or compliance specialists.

The U.S. Bureau of Labor Statistics (BLS) 2012 Occupational Employment and Wage Estimates data (BLS 2012) for the state of California are used to construct ranges of wage rates. The wage data for several similar occupations that are likely to perform the compliance tasks are combined together to form the 5 staff classifications in the analysis. For example, the technical staff 2 wage rate range is a composite of wage rates of chemical, civil, environmental, industrial, mechanical, and health and safety engineering occupations. The minimum 25th percentile, the maximum 75th percentile, and the average of the median wage rate values in the BLS data set are used as low, high, and mid estimates, respectively.

To account for the total labor costs incurred by the reporting entities, which may include employee benefits and overhead costs, staff applied the same adjustment factors that U.S. EPA used in estimating the economic impacts of the federal GHG reporting program (USEPA 2009a). These adjustment factors are a "benefit loading factor" of 0.5 and an "overhead loading factor" of 0.17. In other words, the ranges of wage rates extracted from BLS data are scaled up by a factor of 1.67 to obtain the final "loaded wage rate" numbers for the labor cost analysis. The resulting loaded wage rates for the 5 facility staff classes in 2012 dollars are summarized in Table VI-3.

Table VI-3. Wage Rates Used to Estimate Labor Costs

Facility Staff Class	Loaded Wage Rate ($/ hour)		
	Low	Mid	High
Administrative	20.61	23.91	28.52
Technical 1	35.29	50.05	70.17
Technical 2	53.01	72.12	80.48
Managerial	76.99	91.96	117.95
Lawyer	80.19	111.26	142.32

To estimate the labor costs of each facility type that will be affected by the amended rule in different ways, the labor costs of the applicable compliance task are summed to obtain the total incremental labor costs of the amended GHG reporting rule.

Equipment and Material Costs

Staff does not anticipate that the affected facilities will need to purchase new equipment to comply with the amended regulatory requirements. They should already have the necessary equipment in place for GHG reporting due to the existing California reporting regulation, other federal or local requirements, or normal industry practices. However, staff anticipates that to comply with the proposed amended requirement of determining the carbon and hydrogen content of feedstock, hydrogen production facility operators may need to purchase additional calibration gases for existing process instrumentation. Based on the price of calibration gas offered by gas vendors, the cost of additional calibration gas is estimated to be $240/year.

Cost of Third-Party Verification Service

In working closely with the accredited verifiers and collecting feedback informally provided by verifiers and reporters, ARB staff has compiled estimated ranges of verification service fees that reporting entities spent to comply with the existing verification requirements.

For facilities that will be newly subject to verification requirements (due to inclusion of hydrogen fuel cell emissions, adding reporting of lead production facility, reporting LNG data if interstate pipeline gas is used, or reporting of emulsion from an oil platform), the cost of verification service is estimated as follows. Using the ranges of verification service fees and the estimated time requirements for verifiers to perform specific verification-related tasks, staff estimated the likely ranges of verification service fees, which could either be an intensive verification or less-intensive verification. Most facilities will need to go through an intensive verification at least once every 3 years, and it is assumed that for the other 2 years, approximately half of the facilities will have no major issues to warrant an intensive verification and a less-intensive verification will suffice.[1] Staff estimated the ranges of verification service fees and the time requirements for facility staff to perform various verification-related tasks during both intensive and less-intensive verifications, and applied these costs to each facility type that is expected to see an incremental change to verification-related costs. The annual verification cost in the on-going years is a composite of the cost expected for a typical intensive verification year and a typical less-intensive verification year, where each is weighted equally at 50%.

For facilities that are already subject to verification requirements but are affected by the amended regulatory provisions that require new data to be reported and reviewed by the verifiers, there may be a marginal increase in the amount of time verifiers need to spend on data review. ARB staff anticipates that the verifiers will likely incorporate the

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[1] A site visit and new contract establishment is not required for less-intensive verification, which reduces labor costs associated with verification by approximately 40%-50% when compared to a year in which intensive verification is needed.

additional review time into the existing verification service fee charged to the reporters, and the reporters likely will not see a difference in verification service fee. However, using similar approach for estimating labor costs described in the previous sections, ARB staff conservatively included an estimation of the marginal increase in verification service fee as follows. For reporting of new covered product data and reporting of completion and workover emissions from oil wells, ARB staff estimated that the verifiers may spend an additional 4 to 6 hours on reviewing the new data. Based on staff's experience working with verifiers and reporters and collecting informal feedback, staff estimated that a verifier's average charge rate is in the range of $100-$150 per hour. Multiplying the estimated labor hours and the hourly charge rate, a marginal increase in verification cost of $625 ($400-$900) per facility can be expected.

For the proposed provision requiring refineries to report refinery and fuel supplying operations separately, there is no new data to be reviewed as a result of the amended regulation, and the reporter will likely keep the same verifier after one existing report is split into two separate reports. ARB staff estimated a 15% increase in overall verification service cost to account for the incremental increase in verification service fee that the verifiers may charge for performing overhead tasks associated with preparing an extra verification plan and report. The overall verification cost for one refinery emissions data report is estimated using the same approach as for new verification cost described earlier in this section.

Oil and Gas Sector

For the two proposed provisions affecting onshore oil and gas production facilities (i.e., allowing the use of population count method, and requiring the measurement and reporting of well completion and workover emissions from all oil wells), ARB staff leveraged information available in existing publications and cost estimation performed by the U.S. Environmental Protection Agency (U.S. EPA) to assess the incremental costs to the onshore oil and gas production facility operators.

Cost Saving Resulted from Allowing Population Count Method for Quantifying Fugitive Leak Emissions

By allowing the use of the population count method to quantify fugitive leak emissions, oil and gas facility operators would not be required to use the more expensive quantification method that is required by the extant regulation. A cost saving is anticipated due to this proposed rule amendment, and the saving is estimated as follows.

As a part of the Natural Gas Star Program, U.S. EPA has evaluated the costs and benefits of Directed Inspection and Maintenance Programs (U.S. EPA 2003). U.S. EPA found that approximately 40 components per hour can be screened using an organic vapor analyzer or a toxic vapor analyzer. If the proposed amendment is not implemented, Western State Petroleum Association estimated an additional 900,000 components that would require fugitive leak screening as required by the extant regulation. (The estimate was provided in a previous communication with ARB staff.) The time necessary to do the required screening is approximately 22,500 personnel

hours (900,000 components / 40 components per hour). Assuming the same labor cost of $50/hour that U.S. EPA used in its estimation (which is equivalent to the medium loaded wage rate of a Technical 1 staff listed in Table VI-3), the cost for screening would be approximately $1,125,000 for the entire oil and gas sector. The estimated cost per company is then calculated by dividing the $1,125,000 state-wide sum by the number of affected companies in the sector. Because the proposed amendment provides a cheaper alternative to the existing requirement, the affected operators would see a cost saving from the proposed amendment.

Cost Increase Resulted from Requiring Measurement and Reporting of Well Completion and Workover Emissions from All Oil Wells

Three types of incremental cost are expected from this proposed amended provision:

1. Cost of measuring emissions from completion and workover jobs performed on oil wells.
2. Incremental labor cost expanded by oil and gas facility staff on recordkeeping and preparing emissions data reports for the additional data required by this provision.
3. Incremental increase in verification service fee due to the additional time the verifiers may spend on reviewing the new data.

For the incremental labor cost and verification service fee, ARB staff employed the same estimation method as described in the previous sub-sections. For the cost of measuring emissions from all oil wells, staff used the following estimation approach.

The California Department of Conservation, Division of Oil, Gas, and Geothermal Resources (DOGGR) published a report summarizing the numbers of new wells drilled between 2008 and 2012 in the State (DOGGR 2012). The DOGGR data do not distinguish between gas and oil wells and do not provide statistics on the number of workover jobs done during those years. ARB staff leveraged information from a 2007 oil and gas survey conducted by ARB's Stationary Source Division (SSD 2007) to formulate estimated parameters for filling the data gap. The expected number of completion and workover jobs per year for the entire oil and gas sector is estimated by applying a ratio of the numbers of gas and oil wells and a ratio of the numbers of completion and workover jobs informed by the 2007 survey.

In the 2007 survey, the oil and gas sector reported 117 new gas well completed, 2,061 new oil well completed, and 17,353 oil well worked-over, resulting in a total of 19,414 completion and workover jobs performed on oil wells in 2007. (Each existing or new oil well can be worked-over multiple times in a year, and the number of new well completion and well workovers can vary from year to year.) ARB staff assumed a workover to completion ratio of 8.42 and a gas to oil well ratio of 0.057 can be applied for estimation purposes.

ARB staff took an average of the numbers of new well completed between 2008 and 2012 (2,330) and applied the gas to oil well ratio of 0.057 to obtain an estimated average number of new oil wells completed per year. This produced an estimate of

2,198 oil well completions (2330 x (1-0.057)). To estimate the number of workover jobs per year, the estimated number of complete is multiplied by the workover to completion ratio of 8.42, resulting in an estimate of 18,507 workover jobs per year. Summing the number of completion and workover jobs, it is anticipated that on average, the oil and gas sector may be required to perform as many as 20,705 completion and workover jobs per year (middle-estimate).

To estimate the cost per completion or workover job, ARB staff referenced an existing cost estimate prepared by the U.S. EPA Natural Gas Star Program staff (U.S. EPA 2012). U.S. EPA staff estimated that a Reduced Emissions Completion (REC) job costs approximately $700-$6,500 per day. The measurement of vented gas volume part of a REC job is equivalent to the requirement imposed by the proposed regulatory provision, and it represents a very small fraction of the total REC cost. A typical well clean-up/workover or completion job may take 3-10 days to complete. Therefore, conservatively assuming that 10% of the lower end of the REC cost ($700 x 10% = $70) is related to the required vented gas volume measurement, multiplying the cost per day ($70) by 3 to 10 days provides a range of cost between $210 and $700 per job. The average of the high and low estimates is $455 per completion or workover job.

Multiplying the middle-estimate of the cost per job ($455) by the expected number of jobs to be performed in a year (20,705) in the entire sector, staff estimated that the cost to measure emissions from oil well completion and workover required by the proposed provision would cost the oil and gas sector $9.2 million per year. The cost per company is then calculated by dividing $9.2 million by the number affected companies in the oil and gas sector.

State and Local Government

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies are subject to reporting, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers, some State universities, and other State facilities that emit more than 10,000 metric tons of CO_2e from stationary combustion sources.

Staff reviewed the list of currently reporting entities and identified 28 facilities operated by local government entities and 6 operated by state government entities may be impacted by the proposed regulation amendments. Because a local government entity may operate multiple facilities that are each subject to the reporting regulation, there are 21 local government entities impacted by the proposed amendments. However, the affected state government entities are each considered a separate entity for the purpose of this economic impact analysis. The 28 facilities operated by local agencies are listed in Table VI-4, and the 6 facilities operated by state government entities are listed in Table VI-5.

Table VI-4. List of Affected Local Government Entities

Local Government Entity	Affected Facilities
City of Palo Alto	City of Palo Alto Water Quality Control Treatment Plant
City of Pasadena	Pasadena Water and Power, Glenarm
City of Riverside	City of Riverside, Public Works Department, Regional H2O Plant
City of San Diego	Public Utilities Dept, Point Loma Treatment Plant Public Utilities Dept, Pump Station 2
City of San Jose/Santa Clara	San Jose/Santa Clara Water Pollution Control Plant
County of LA	Olive View Medical Center, Los Angeles County Department of Health Services
County of Sacramento	Kiefer Landfill, Department of Waste Management and Recycling
County of Sonoma	Sonoma County Landfill Gas to Energy
Dublin San Ramon Services District	Dublin San Ramon Services District
East Bay MUD	East Bay Municipal Utility District
Encina Wastewater Authority	Encina Water Pollution Control Facility
Imperial Irrigation District	Imperial Irrigation District (IID), Niland Gas Turbine Plant
John Wayne Airport Orange County	John Wayne Airport Orange County
LA County Sanitation District	Calabasas LF Puente Hills Landfill Spadra Landfill
LA Department of Water & Power	Haynes Generating Station Valley Generating Station
Northern California Power Agency	Geothermal Plant No. 1 Geothermal Plant No. 2
Orange County Sanitation District	Orange County Sanitation District - Plant 1 Orange County Sanitation District - Plant 2
Plumas-Sierra Rural Electric Cooperative	High Sierra Cogeneration
Southern California Public Power Authority	BWP/MPP Electricity Generating Facilities at 164 W. Magnolia
San Francisco International Airport	San Francisco International Airport (SFO)
Sacramento Municipal Utility District	Sacramento Municipal Utility District (SMUD) , Cosumnes Power Plant

Table VI-5. List of Affected State Government Entities

Affected State Government Entities
Avenal State Prison
California Polytechnic State University
California State University, Fullerton
University of California, Riverside, UCR
University of California, Santa Barbara
University of California, Santa Cruz, UCSC EH&S Office

Since the proposed regulatory amendments apply the same to affected facilities regardless of public or private ownership, the same cost estimation methodology used for privately-owned facilities was used for local and state government entities. To estimate the total costs to the affected local government entities, staff multiplied the

expected incremental cost per facility by 28 facilities, then divide the total cost by 21 local government entities to obtain the incremental cost per entity. The cost estimation results are presented in Section A.4.

Small Businesses

As a part of the 2012 regulation amendment, a reporting provision was added instructing reporters to indicate in their emissions data report whether they qualify for "small business entity" status pursuant to California Government Code Section 11342.610 (CGC 2012). Twenty-five reporters claimed small business entity status in their 2012 emissions data reports. Seven of which are expected to see a cost impact due to the amended rule provisions.

ARB staff verified the small business status of each of these reporting entities by conducting a detailed review of their corporate owner information and electricity generation and transmission information (if the reporting entity operates a power plant or is an electric utility or marketer), as well as conducting research on their parent company to determine the size and dominance. It was determined that none of these reporters qualify for small business status based on the California Government Code Section 11342.610 definition. The process for verifying small business status is described in this section.

A small business, is defined by the California Government Code Section 11342.610 (CGC 2012) as:

> *(a) "Small business" means a business activity in agriculture, general construction, special trade construction, retail trade, wholesale trade, services, transportation and warehousing, manufacturing, generation and transmission of electric power, or a health care facility, unless excluded in subdivision (b), that is both of the following:*
>
> > *(1) Independently owned and operated.*
> > *(2) Not dominant in its field of operation.*
>
> *(b) "Small business" does not include the following professional and business activities:*
>
> > *(1) A financial institution including a bank, a trust, a savings and loan association, a thrift institution, a consumer finance company, a commercial finance company, an industrial finance company, a credit union, a mortgage and investment banker, a securities broker-dealer, or an investment adviser.*
> > *(2) An insurance company, either stock or mutual.*
> > *(3) A mineral, oil, or gas broker.*
> > *(4) A subdivider or developer.*
> > *(5) A landscape architect, an architect, or a building designer.*
> > *(6) An entity organized as a nonprofit institution.*

(7) An entertainment activity or production, including a motion picture, a stage performance, a television or radio station, or a production company.
(8) A utility, a water company, or a power transmission company generating and transmitting more than 4.5 million kilowatt hours annually.
(9) A petroleum producer, a natural gas producer, a refiner, or a pipeline.
(10) A manufacturing enterprise exceeding 250 employees.
(11) A health care facility exceeding 150 beds or one million five hundred thousand dollars ($1,500,000) in annual gross receipts.

(c) "Small business" does not include the following business activities:

(1) Agriculture, where the annual gross receipts exceed one million dollars ($1,000,000).
(2) General construction, where the annual gross receipts exceed nine million five hundred thousand dollars ($9,500,000).
(3) Special trade construction, where the annual gross receipts exceed five million dollars ($5,000,000).
(4) Retail trade, where the annual gross receipts exceed two million dollars ($2,000,000).
(5) Wholesale trade, where the annual gross receipts exceed nine million five hundred thousand dollars ($9,500,000).
(6) Services, where the annual gross receipts exceed two million dollars ($2,000,000).
(7) Transportation and warehousing, where the annual gross receipts exceed one million five hundred thousand dollars ($1,500,000).

In verifying each reporting entity's small business status, ARB staff used the following interpretations of the definition:

- "Independently owned and operated" means the facility is owned by individual private investors. The facility is not owned by a large corporation with indistinguishably numerous investors or have multiple subsidiaries each with its own brand name in its field of operation. (CGC Section 11342.610(a)(1))
- A supplier of natural gas or petroleum fuel is an "oil or gas broker." (CGC Section 11342.610(b)(3))
- An electricity generating facility with a primary NAICS code that starts with 22 is "a utility or a power transmission company." If the electricity generating facility generates more than 4.5 million kilowatt hours annually, it is not considered "small." (CGC Section 11342.610(b)(8))
- An electricity importer/exporter, retail provider, or marketer is "a utility or a power transmission company." If the electricity entity transacted or transmitted more

than 4.5 million kilowatt hours annually, it is not considered "small." (CGC Section 11342.610(b)(8))

After reviewing all the available information gathered from their emissions data reports and from additional research on parent companies, it was determined that there are no small business entities captured by the reporting regulation.

A.4. Economic Impacts of Proposed Regulation

This section presents the results of staff's analysis of the economic impacts of the proposed regulation. ARB staff first presents a state-wide overview of the cost impacts by affected sectors, which include all of the affected entities in the private and public sectors. The following subsections discuss the impacts on private businesses, small businesses, state and local agencies, consumers, employment, business creation and elimination, and California business competitiveness.

A.4.1. Overview of State-Wide Costs

Only the direct incremental costs of complying with the proposed rule amendments are included in this analysis. Using the methods described in Section A.3, staff's estimates of the cost impacts for each affected sectors are summarized in Tables VI-6a, VI-6b, VI-7a, and VI-7b (next page), which include all the affected entities in the private and public sectors. Although a range of costs was estimated for each of the cost numbers presented in these tables, only the middle-estimate values are shown to streamline the presentation. These estimated numbers are not meant to be a precise projection of the costs; however, the numbers are not rounded for the purpose of facilitating reviews under the state administrative procedures.

Table VI-6a. Sector-Wide Incremental Cost Impacts for Private Industry Sectors

Industry Sector	Number of Affected Companies[1]	Number of Affected Reporting Entities[1]	Sector-Wide Incremental Costs (2012$)[2]		
			1st-Year	On-going Years	8-Year Cost[3]
Oil & Gas Production	17	27	8,150,088	8,140,918	55,138,715
Petroleum Refineries	9	14	54,692	38,587	277,416
Food Manufacturing	33	58	56,211	35,212	259,451
General Stationary Fuel Combustion Facilities	59	76	77,052	22,610	207,554
Power Generation	35	55	59,938	8,185	107,179
Hydrogen Production	3	7	19,329	12,084	89,077
Lead Production	1	1	15,715	11,477	81,958
Lime Manufacturing	1	1	3,223	2,923	20,094
Fuel Supplier	11	11	4,868	2,201	17,574
Glass Production	1	1	861	194	1,983
Total	170	251	8,441,978	8,274,392	56,201,001

[1] As defined in the GHG reporting regulation, a reporting entity is a facility, a supplier of fuel or CO_2, or an electric power entity. A business or a company may operate multiple facilities (and therefore multiple reporting entities) that are each subject to the reporting regulation and may each be impacted by the amendments differently. For the operator of industrial facilities, the point of regulation or the regulated unit is a facility, not its company.

[2] Although a range of conservatively high and conservatively low costs were estimated, the table only shows the middle-estimate values for the purpose of streamlining the presentation and facilitating administrative review.

[3] Future costs are discounted at 5%. A time horizon of 8 years is used for the regulation implementation from 2014 to 2021.

Table VI-6b. Estimated Average Incremental Cost Impacts for an Average Business Entity

		Incremental Costs per Business Entity (2012$)[1]		
Industry Sector	Number of Affected Companies	1st-Year	On-going Years	8-Year Cost[2]
Oil & Gas Production	17	479,417	478,878	3,243,454
Petroleum Refineries	9	6,077	4,287	30,824
Food Manufacturing	33	1,703	1,067	7,862
General Stationary Fuel Combustion Facilities	59	1,306	383	3,518
Power Generation	35	1,713	234	3,062
Hydrogen Production	3	6,443	4,028	29,692
Lead Production	1	15,715	11,477	81,958
Lime Manufacturing	1	3,223	2,923	20,094
Fuel Supplier	11	443	200	1,598
Glass Production	1	861	194	1,983

[1] Incremental costs for an average business entity are calculated by dividing the sector-wide total by the number of affected companies in the sector. Although a range of conservatively high and conservatively low costs were estimated, the table only shows the middle-estimate values for the purpose of streamlining the presentation and facilitating administrative review.

[2] Future costs are discounted at 5%. A time horizon of 8 years is used for the regulation implementation from 2014 to 2021.

Table VI-7a. Incremental Cost Impacts for Local and State Government Entities

Industry Sector	Number of Affected Government Entities[1]	Number of Affected Reporting Entities[1]	Sector-Wide Incremental Costs (2012$)[2]		
			1st-Year	On-going Years	8-Year Cost[3]
Local Government Entities	28	21	24,239	5,263	54,617
State Government Entities	6	6	6,028	1,360	13,878
Total	28	34	30,267	6,623	68,495

[1] As defined in the GHG reporting regulation, a reporting entity is a facility, a supplier of fuel or CO_2, or an electric power entity. A government entity may operate multiple facilities (and therefore multiple reporting entities) that are each subject to the reporting regulation and may each be impacted by the amendments differently. The point of regulation or the regulated unit is a facility, not a government entity.

[2] Although a range of conservatively high and conservatively low costs were estimated, the table only shows the middle-estimate values for the purpose of streamlining the presentation and facilitating administrative review.

[3] Future costs are discounted at 5%. A time horizon of 8 years is used for the regulation implementation from 2014 to 2021.

Table VI-7b. Estimated Average Incremental Cost Impacts for an Average Local or State Government Entity

Industry Sector	Number of Affected Government Entities[1]	Incremental Costs per Government Entity (2012$)[1]		
		1st-Year	On-going Years	8-Year Cost[2]
Local Government Entities	21	1,154	251	2,601
State Government Entities	6	1,005	227	2,313

[1] Incremental costs for an average government entity are calculated by dividing the sector-wide total by the number of affected government entities in the sector. Although a range of conservatively high and conservatively low costs were estimated, the table only shows the middle-estimate values for the purpose of streamlining the presentation and facilitating administrative review.

[2] Future costs are discounted at 5%. A time horizon of 8 years is used for the regulation implementation from 2014 to 2021.

As shown in Tables VI-6a and VI-6b, the proposed rule amendment is expected to have a state-wide incremental cost of $8 million annually on private businesses. Using a discount rate of 5% and a time horizon of 8 years, the total incremental cost increase is approximately $56 million over 8 years. Approximately 98.1% of the total costs to private businesses occur in the oil and gas sector. Annually, an average business entity in the oil and gas sector can expect to see a cost increase of $479,000 per year, and a lead production facility that is newly captured by the reporting regulation can see a cost increase of $15,700 in the initial year and $11,500 in the ongoing years. The annual costs to the remaining facilities and fuel suppliers range between $200 and $4,000.

As shown in Tables VI-7a and VI-7b, the proposed rule amendment is expected to have an annual state-wide incremental cost of $30,000 in the first year and $6,600 in the ongoing years for state and local government entities. The total incremental cost increase is approximately $68,500 over 8 years. Annually, an average government entity can expect to see a cost increase in the low-$1,000's range in the initial year, and less than $300 in the ongoing years. The average 8-year cost per government entity is in the mid-$2,000 range.

A.4.2. Discussions of Impacts

Impacts to California Businesses

The proposed GHG reporting regulation focuses on the largest stationary sources of GHG emissions and other sources that must be included for an effective cap-and-trade program. The specific incremental cost for a facility subject to GHG reporting can vary significantly depending on each facility's unique situation in terms of its sector designation, type and size of its fuel combustion equipment, facility complexity, emissions level, and its current monitoring and sampling practices as compared to its future requirements under this proposal.

For an individual reporting entity (which may either be an industrial facility or a fuel supplier, as defined in the GHG reporting regulation), the incremental cost per entity could range widely. Incremental costs for typical businesses (other than those in the oil and gas production sector) subject to the proposed amendments will generally be small for facilities that are already subject to current GHG reporting programs, because the bulk of the baseline costs will be incurred complying with the existing ARB reporting regulation.

With the proposed amendments, ARB staff anticipates additional costs during the initial year for certain facility types, as reporters become familiar with the new requirements, update or develop GHG monitoring plans, and develop expertise with the new reporting systems and methods. However, ARB staff anticipates industry costs to decline over time as the amended GHG reporting requirements become incorporated into standard facility practices. See Tables VI-6b and VI-7b for the estimated cost per reporting entity.

The main sources of uncertainties in the economic impact analysis are from the ranges of wage rates in the U.S. Bureau of Labor Statistics data and the ranges of the estimated time requirement to perform compliance tasks. A high estimate represents the scenario in which the affected entity uses staff whose salary is high in their

respective staff classifications, and the amount of time that the high-salaried staff takes in doing the compliance tasks is also on the high end of the range of estimates. On the other hand, a low estimate represents the scenario in which the affected entity uses staff whose salary is on the low side of the wage rate range, and each staff takes little time to accomplish the compliance tasks. The high and low estimates are calculated for bounding purposes, and they are extremely unlikely in reality because private businesses tend to minimize cost by maximizing efficiency. When factoring in all uncertainties in either direction, the net costs are likely to be close to the middle estimates.

Impacts to Small Businesses

As explained in section A.3.2, the *Small Businesses* sub-section, staff has determined that the proposed regulation amendment does not impact any small businesses. There are no small business entities captured by the reporting regulation.

Impacts to California State and Local Agencies

Staff has determined that the proposed amendments will have marginal impacts on GHG emitting facilities operated by local and state government entities (e.g., landfills, wastewater treatment plant, municipality-owned power plants, state universities and prison facilities). Using the methods described previously, we estimated that the affected local government entities will see a marginal cost increase ranging from $300 to $1,200 per year. These local and state government entities are expected to absorb the incremental costs with existing staff and operation budget.

Adoption of the proposed amendments is expected to require continued funding for ARB to administer the program. The amendments will be implemented using existing ARB staffing, and no change in staffing level is needed to administer the program under the amended rule. Any ARB fiscal expenses needed for implementing the proposed amendments are already accounted for in the current operational budget that was approved as a part of the previous rule amendments.

Potential Impact on Consumers

No noticeable change in consumer prices is expected from the amendments to the reporting regulation because the compliance costs will have only a minor impact on the affected businesses.

Impact on Employment

Since the incremental compliance costs associated with the amended GHG reporting regulation impose only a very small impact on California businesses, staff expects no significant change in employment due to the regulation amendments.

Impact on Business Creation, Elimination, or Expansion

No change is expected to occur in the status of California businesses as a result of the amendments to the reporting regulation. This is because the proposed amendments are expected to impose only minor costs on businesses in California. However, staff

anticipates that existing contractors that perform work for the oil and gas sector may expand to meet additional needs, and existing consulting businesses that assist regulated entities with emissions reporting and verification may see new business opportunities as the result of the proposed amendments.

Staff does not anticipate there will be noticeable changes in the number of businesses created, eliminated, or expanded as the result of the propose regulation. Existing firms will likely attempt to absorb as much of the new workload as possible.

Impacts to California Business Competitiveness

The reporting regulation amendments would have little or no impact on the ability of California businesses to compete with businesses in other states. This is because the regulation does not impose a significant cost impact on California businesses. In addition, most businesses affected by the regulation are power plants or other local manufacturing operations serving California customers, and may not be strongly subject to interstate competition. However, the proposed regulation could have an adverse impact on the ability of some California businesses operating with little or no margin of profitability to compete with businesses in other states.

B. Major Regulations

Health and Safety Code section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to the proposed regulation before adopting any major regulation. For purposes of this section, "major regulation" means any regulation that will have an economic impact on the state's business enterprises in an amount exceeding ten million dollars ($10,000,000) in any single year, as estimated by the board, department, or office within the agency proposing to adopt the regulation in the assessment required by subdivision (a of Section 11346.3 of the Govt. Code. ARB staff has determined that the amendments to the proposed regulations are not a major regulation as defined above.

C. Reasonable Alternatives to the Regulation and the Agency's Reason for Rejecting those Alternatives

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed, would be as effective and less burdensome to affected private persons than the proposed action, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provision of law. Since the proposed amendments are made to the existing reporting regulation, and given that these proposed amendments do not have a significant adverse fiscal or economic impact, no alternatives, other than one in which no regulatory amendments would be made and ones in which the specific amendments to various sector requirements are compared to harmonization with the

applicable U.S. EPA rule requirements or data collected from other sources, were considered. Alternatives considered and staff's recommendations regarding these alternatives are found in section D of Chapter II of this report.

D. Significant Adverse Economic Impact Directly Affecting Business

The proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses. The incremental cost impacts for a majority of the businesses are between $200 and $3,200 per year and can be easily absorbed into their normal cost of operation. The oil and gas production companies that may see a higher incremental cost typically have an annual revenue of several million dollars per year. The cost impact of the proposed action is an insignificant fraction of their total revenue.

E. Justification for Adopting Regulations Different from Federal Regulations

The U.S. EPA requires mandatory GHG reporting (Mandatory Reporting of Greenhouse Gases; Final Rule. 40 CFR Parts 86, 87, 89, 90, 94, and 98. United States Environmental Protection Agency. October 30, 2009). Staff does not believe the proposed regulation is inconsistent with existing federal law. In fact, this proposed amended regulation was developed to minimize, to the greatest extent possible, any redundant State and federal reporting, while also ensuring that ARB is collecting the necessary additional information required by California's various GHG programs, including the cap-and-trade regulation, fee regulation, and the statewide GHG inventory.

VII. SUMMARY AND RATIONALE FOR EACH REGULATORY PROVISION

This chapter of the staff report provides a summary of each specific change to the reporting regulation and the reason, or rationale, for the change. Any sections of the reporting regulation without changes are not included in this summary and rationale section.

Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Subarticle 1.

General Requirements for Greenhouse Gas Reporting

Section 95101. Applicability.

This section of the reporting regulation specifies which facilities and entities are subject to greenhouse gas emissions reporting under the reporting regulation. It also specifies methods for determining applicability, which entities are excluded from reporting, the

requirements for demonstrating lack of applicability, and the requirements for ceasing reporting if applicability is no longer met.

Summary of Proposed Updates Section 95101(a)(1)(B)

This modification explicitly indicates that CO_2, CH_4 and N_2O are the only greenhouse gases that need to be considered for the applicability threshold.

Rationale for Proposed Updates Section 95101(a)(1)(B)

This change is necessary to ensure that only CO_2, CH_4 and N_2O emissions are used for the applicability determination.

Summary of Proposed Updates Section 95101(a)(1)(B)(8)

Operators of lead production facilities are added as a new reporting sector in the regulation.

Rationale for Proposed Updates Section 95101(a)(1)(B)(8)

This change is necessary to make lead production facilities in California subject to GHG reporting requirements when they are above the reporting threshold of 10,000 MT CO_2e per year.

Summary of Proposed Updates Section 95101(a)(1)(G)

This new subsection allows flexibility by making facilities in these industrial sectors in 40 CFR part 98 subject to GHG reporting requirements when they meet the applicability threshold. Facilities in these new sectors are not currently covered in the reporting regulation because ARB had not identified any of them as operating in California. This change allows flexibility to immediately require GHG reporting if and when a facility begins operation rather than go through a separate regulatory update each time to add sectors separately.

Rationale for Proposed Updates Section 95101(a)(1)(G)

This change is necessary to ensure that if any of the noted sectors commence industrial processes in California, they will be required to report consistent with U.S. EPA 40 CFR part 98 requirements.

Summary of Proposed Updates Section 95101(a)(2)

Removed historical references to prior data years.

Rationale for Proposed Updates Section 95101(a)(2)

For consistency, reference to prior data reporting years has been removed.

Summary of Proposed Updates Section 95101(a)(3)

This update was added to ensure reporting is facilitated by the same responsible party throughout an entire compliance period.

Rationale for Proposed Updates Section 95101(a)(3)

To support the Cap-and-Trade program, this update ensures consistency in reporting and verification responsibilities, in situations of common ownership or common control.

Summary of Proposed Updates Section 95101(b)

The phrase "using the requirements of 40 CFR §98.2(b)-(c), except" was removed and the term "industrial" was removed.

Rationale for Proposed Updates Section 95101(b)

This change is necessary to ensure the applicability determination is done correctly and is consistent with the changes in sections 95101(b)(1)-(6). The term industrial was removed because some reporters subject to the regulation, such as universities, questioned if they were "industrial" facilities so the term was removed to remove ambiguity from the applicability requirements.

Summary of Proposed Updates Section 95101(b)(1)

This update adds the terms CO_2, CH_4, and N_2O for the purposes of performing emissions threshold analysis.

Rationale for Proposed Updates Section 95101(b)(1)

This change is necessary to clarify that CO_2, CH_4, and N_2O are the only greenhouse gases subject to reporting. The inclusion of this language removes ambiguity by explicitly stating that only these three gases are to be included in the threshold analysis will prevent uncertainty in determining applicability.

Summary of Proposed Updates Section 95101(b)(2)

Added language to clarify that vented and fugitive emissions must also be included in the total facility emissions to be compared with the 25,000 metric ton CO_2e threshold specified in sections 95103(a) and 95103(f). If these emissions exceed the 25,000 metric ton CO_2e threshold, the reporting entity must submit a full GHG emissions data report and obtain verification service. Staff also added the citation for referencing the 10,000 metric ton CO_2e threshold.

Rationale for Proposed Updates Section 95101(b)(2)

This proposed language is added for clarity in response to feedback received from stakeholders during program implementation. It is necessary to ensure reporting entities understand the reporting threshold.

Summary of Proposed Updates Section 95101(b)(6)

Proposed new language adds emissions from hydrogen fuel cell units to the 10,000 metric ton CO_2e applicability thresholds.

Rationale for Proposed Updates Section 95101(b)(6)

This change was necessary to address a growth in installation of new hydrogen fuel cell units was observed in the past few years. To ensure accurate numbers are used for the state-wide GHG inventory, emission calculation methods for hydrogen fuel cells are added to section 95112(f). The new paragraph 95101(b)(6) specifies that reporters must also include hydrogen fuel cell emissions in applicability determination when comparing to the 10,000 and 25,000 metric ton CO_2e thresholds.

Summary of Proposed Updates Section 95101(c)(1)

The term 'refineries' was changed to 'refiners.'

Rationale for Proposed Updates Section 95101(c)(1)

This update provides clarification for reporting in section 95121 and is consistent with the term defined in section 95102(a).

Summary of Proposed Updates Section 95101(c)(5)

The term 'imported' was added to the subparagraph to clarify this applicability rule is applicable only to consignees of imported compressed natural gas and liquefied natural gas.

Rationale for Proposed Updates Section 95101(c)(5)

This change was necessary to ensure consistent interpretation of reporting requirements for imported compressed natural gas and liquefied natural gas.

Summary of Proposed Updates Section 95101(c)(10)

Subparagraph (10) requires liquefied natural gas production facility operators to report GHG emissions, subject to the applicability thresholds, if the facility receives gas for liquefaction from an interstate natural gas pipeline.

Rationale for Proposed Updates Section 95101(c)(10)

This change was necessary to ensure complete reporting of all natural gas supplied within California.

Summary of Proposed Updates Section 95101(f)(8)

This subsection listing the exceptions to sectors where U.S. EPA GHG reporting was not required in California was removed from the regulatory text.

Rationale for Proposed Updates Section 95101(f)(8)

This change was made to ensure the modifications made to section 95101(a)(1)(G) were not contradicted.

Summary of Proposed Updates Section 95101(f)(9)

This subsection was renumbered due to the deletion of section 95101(f)(8).

Rationale for Proposed Updates Section 95101(f)(9)

This change was made to ensure consistent section numbering.

Summary of Proposed Updates Section 95101(h)

New proposed language clarifies that a reporting entity covered under the Cap-and-Trade program must continue to comply with all reporting requirements until there is no longer a compliance obligation. The new language also provides instruction for how reporting entities should determine the number of additional years that they must continue to report before they can exit the reporting program.

Rationale for Proposed Updates Section 95101(h)

This change is necessary to ensure the cessation of reporting requirements are unambiguous. The original cessation of reporting requirements were adapted from 40 CFR part 98, which does not collect data to support a Cap-and-Trade program. The added language to this section clarifies that a reporting entity must first follow the Cap-and-Trade program applicability requirements until they are no longer subject to them. Once the Cap-and-Trade applicability ends, the reporting entity must then follow the reporting cessation requirements to exit the reporting program.

Summary of Proposed Updates Section 95101(h)(3)

Existing paragraph 95101(h)(3) is deleted. Paragraphs are renumbered so that the formerly paragraph 95101(h)(4) now becomes paragraph 95101(h)(3). The words "verify" are removed from the renumbered paragraph 95101(h)(3).

Rationale for Proposed Updates Section 95101(h)(3)

This is change is necessary because the cessation of verification requirements were expanded to section 95101(i). Section 95101(h) is now dedicated to cessation of reporting, while the new section 95101(i) is now dedicated to cessation of verification. These rule changes are made for clarity.

Summary of Proposed Updates Section 95101(i)

This new section clarifies the existing cessation of verification requirements. Reporting entities are required to notify ARB if they meet verification cessation requirements and intend to no longer obtain verification services. Reporting entities subject to the Cap-and-Trade regulation continue to verify emissions data reports until they no longer have a compliance obligation. In other words, when a reporting entity has met the reporting cessation requirements and no longer submits an emissions data report, verification

also ends.

Rationale for Proposed Updates Section 95101(i)

This change is necessary to clarify existing cessation of verification requirements.

Summary of Proposed Updates Section 95101(i)(1)

This change specifies cessation of verification requirements that are applicable to reporting entities that shut down. Verification is not required for the emissions data report during the first full calendar year of non-operation that follows shut down.

Rationale for Proposed Updates Section 95101(i)(1)

The proposed change is needed to clarify the verification requirements.

Summary of Proposed Updates Section 95101(i)(2)

Only the first year in which a power entity ceases to import or export power, is required to be verified. Verification is not required for the emissions data report during the first full calendar year of non-operation that follows.

Rationale for Proposed Updates Section 95101(i)(2)

The change is needed to clarify the verification requirements.

Summary of Proposed Updates Section 95101(i)(3)

Facility operators or suppliers not subject to the Cap-and-Trade regulation and that drop below the verification threshold may elect to cease verification during the second data year emissions are below the verification threshold.

Rationale for Proposed Updates Section 95101(i)(3)

The update is needed to clarify the verification requirements.

Section 95102. Definitions.

This section defines all key terms used in the regulation that may not be in common use or which may potentially be ambiguous without a regulatory definition. Definitions have been edited, added, and in some cases, removed to clarify the meaning and intent of the regulation.

Summary of Proposed Updates Section 95102(a)

Additions to this section are designed to ensure consistent interpretation of the reporting requirements and include: additions to support electric power entity reporting, clarifications to the verification process, deletions of existing product data definitions and additions to support Appendix B of the reporting regulation.

Rationale for Proposed Updates Section 95102(a)

This section is necessary to ensure that those subject to the regulation are able to understand and interpret the regulation correctly, and to avoid ambiguity and improve compliance with the regulation. ARB staff has attempted to include all key terms used in the regulation, which are usually included without modification to support consistent interpretation of the state and federal regulation. Deletions, additions, and modifications from the current version of the reporting regulation are necessary to ensure clear interpretation of terms related to the other amendments to the regulation in this rulemaking.

Summary of Proposed Updates Section 95102(b)

This section was added to split the product data definitions from the emissions definitions.

Rationale for Proposed Updates Section 95102(b)

This change is necessary to ensure there is a central location within the reporting regulation that defines the many different types of product data.

Section 95103. Greenhouse Gas Reporting Requirements.

This section contains the reporting requirements for all facilities subject to this regulation, including abbreviated reporting, reporting and verification schedules, accuracy specifications, and other requirements.

Summary of Proposed Updates Section 95103(a)

The language added to this section to clarifies that only U.S. EPA reporting sectors listed in the California GHG reporting regulation are to be considered for this abbreviated reporting applicability requirement.

Rationale for Proposed Updates Section 95103(a)

The clarification is needed to state that the applicability for abbreviated reporters is based upon the reporting entity sectors listed in the California GHG reporting regulation as opposed to all sectors in the U.S. EPA reporting rule.

Summary of Proposed Updates Section 95103(a)(1)

Staff added requirements for abbreviated reporters to provide their natural gas supplier service identification number or other primary account identifier. This information, which is in addition to providing the name and customer account number of their natural gas supplier, ensures consistent reporting of natural gas supplier information for both abbreviated reporters and full reporters reporting information per section 95115(k).

Rationale for Proposed Updates Section 95103(a)(1)

This new language was added to facilitate identification of the abbreviated reporter's natural gas supplier for purposes of ensuring accurate natural gas supplier compliance obligation calculations. This revision attains consistency of reporting natural gas supplier information for both abbreviated reporters and full reporters.

Summary of Proposed Updates Section 95103(a)(2)

Staff added requirements for abbreviated reporters to provide additional information attributing percentages of aggregated fuel consumption to the unit type categories specified in section 95115(h): boiler, reciprocating internal combustion engine, turbine, process heater, and other. Require abbreviated reporters to separately report electricity generating units from other general stationary combustion units. Engineering estimation and best available method are acceptable.

Rationale for Proposed Updates Section 95103(a)(2)

This new language was added to track the actual source of emissions, consistent with the data submitted by full reporters. This information supports the GHG emission inventory.

Summary of Proposed Updates Section 95103(a)(6)

The proposed change requires abbreviated reporters operating a hydrogen fuel cell unit at their facility to report emissions from the hydrogen fuel cell unit by following the new emission calculation methods in section 95112(f).

Rationale for Proposed Updates Section 95103(a)(6)

This change allows ARB to monitor the growth in the new hydrogen fuel cell installation in California to ensure consistency in the way that emission sources are captured by the mandatory reporting program at all emission applicability thresholds.

Summary of Proposed Updates Section 95103(a)(8)

Removed reference to historical data.

Rationale for Proposed Updates Section 95103(a)(8)

This change is necessary to ensure the reporting requirements are clear and unambiguous.

Summary of Proposed Updates Section 95103(a)(9)

Proposed updates in this sub-section require abbreviated reporters to correct errors in their emissions data reports, if discovered after the reporting deadline. It also clarifies that this applies to any error, not just errors that are greater the five percent.

Rationale for Proposed Updates Section 95103(a)(9)

Previously, the rule language was not clear regarding what an abbreviated reporter should do when an error is discovered in the emissions data report. The new rule language provides a mechanism for abbreviated reporters to make a correction if an error in the emissions data report is discovered after the reporting deadline. This ensures the most accurate data reporting possible. The language regarding a threshold of error correction was removed to ensure that all errors are corrected to maintain an accurate assessment of the reported data.

Summary of Proposed Updates Section 95103(e)

This section was updated to clarify the year of data submittal and the year of the data to be reported.

Rationale for Proposed Updates Section 95103(e)

This change was needed, in conjunction with the revision to the definition of "emissions data report," to clearly establish that an emissions data report is for the submission of required data for the calendar year prior to the year in which the report is due.

Summary of Proposed Updates Section 95103(f)

Verification requirements in this section have been updated to include language that reflects the updated definition to "emissions data report" and clarifications made to cessation of verification in section 95101(i).

Rationale for Proposed Updates Section 95103(f)

This change is necessary to ensure a consistent interpretation of the term "emissions data report" and cessation of verification.

Summary of Proposed Updates Section 95103(h)

Proposed changes describe the reporting method for reporting new requirements for 2013 data reported in 2014, and removes obsolete historical references.

Rationale for Proposed Updates Section 95103(h)

This change is necessary to ensure that certain data from 2013 will be reported in 2014. This change is important for purposes of supporting the allocation of allowances and benchmarking process in the Cap-and-Trade program. These modifications also indicate which requirements are applicable for 2014 data reported in 2015.

Summary of Proposed Updates Section 95103(i)

This section has been updated to allow fuel suppliers to use *de minimis* provisions in their reporting.

Rationale for Proposed Updates Section 95103(i)

This change is necessary to ensure supplier reporting is consistent with other facilities.

Summary of Proposed Updates Section 95103(j)(3)

New biomethane procurement reporting requirements were added to the section in order to ensure that reporters have the requisite data available for meeting the biomethane verification requirements.

Rationale for Proposed Updates Section 95103(j)(3)

This change is necessary to ensure that reporters have the requisite data available for meeting the biomethane verification requirements in 95131(i) and the requirements of section 95852.1.1 of the Cap-and-Trade regulation that exempts this fuel from a compliance obligation.

Summary of Proposed Updates Section 95103(k)

Proposed language was added to require that operators and suppliers subject to the measurement accuracy requirements of 40 CFR §98.3(i) must meet those requirements for non-covered emissions and non-covered product data.

Rationale for Proposed Updates Section 95103(k)

The language was added to clarify that non-covered product data and non-covered emission data does not need to meet the requirements of section 95103(k).

Summary of Proposed Updates Section 95103(k)(7)(C)

New language was added to exempt non-financial transaction meters used by Public Utility Gas Corporations (PUGCs) that conform to the standard California Public Utilities Commission (CPUC) General Order 58A.

Rationale for Proposed Updates Section 95103(k)(7)(C)

This change was necessary to avoid situations where PUGCs are subject to more than one metering standard for a single meter. This provision ensures the continued

accuracy of the non-financial transaction meters by requiring the PUGC to demonstrate that the non-financial transaction meters are operated and maintained in conformance to a standard that meets the accuracy requirements specified in CPUC General Order 58A, which specifies measurement accuracy within five percent.

Summary of Proposed Updates Section 95103(k)(9)(A)

The reference to historical data was removed.

Rationale for Proposed Updates Section 95103(k)(9)(A)

This change is necessary to ensure the reporting requirements are clear and unambiguous.

Summary of Proposed Updates Section 95103(k)(11)

New language was added specifying that process throughput data required in section 95113(l)(3)-(4) can be measured using the inventory measurement methods described in section 95103(k)(11).

Rationale for Proposed Updates Section 95103(k)(11)

This change was made to ensure that process throughput data measurements will be performed consistently and be held to the standards of section 95103(k).

Summary of Proposed Updates Section 95103(l)

Language was added to allow for the voluntary exclusion of covered product data from a material misstatement assessment, except for the cement sector requirements in section 95110(d). If covered product data is excluded then the reporting entity must describe the exclusion and estimate the magnitude of the exclusion. A section reference was modified to include section 95124, lead production. If covered product data is excluded, then that data is not allowed for use in the allocation of allowances determination.

Rationale for Proposed Updates Section 95103(l)

This change was necessary to allow for flexibility during the verification of covered product data. The update of the section reference is necessary to allow reporters the option to not include product data, if the accuracy of the data cannot be demonstrated.

Summary of Proposed Updates Section 95103(m)

This change ensures product data is also subject to the change of methodology provisions outlined in this section.

Rationale for Proposed Updates Section 95103(m)

This change was necessary to ensure consistent application of the reporting regulation.

Summary of Proposed Updates Section 95103(m)(3)

Updated language to clarify the intent of the section.

Rationale for Proposed Updates Section 95103(m)(3)

This change was necessary to ensure consistent interpretation of this regulatory requirement.

Summary of Proposed Updates Section 95103(m)(5)

Subparagraph (5) was added to provide requirements for choosing measurement and calculation methods in the event that regulatory revisions impose new or revised reporting or calculation requirements.

Rationale for Proposed Updates Section 95103(m)(5)

This change was necessary to ensure consistent interpretation of this regulatory requirement when new or revised rules are implemented.

Summary of Proposed Updates Section 95103(n)

This new subsection outlines notification requirements and reporting responsibilities for a reporting entity that undergoes a change of ownership or operational control.

Rationale for Proposed Updates Section 95103(n)

This change is necessary to ensure the consistent, continuous reporting by a facility or supplier during an ownership change or change in operational control. Staff added language to outline the process, including who to notify at ARB, when to notify them, and who is responsible for reporting and verification.

Summary of Proposed Updates Section 95103(o)

This section was renumbered to accommodate the addition of section 95103(n).

Rationale for Proposed Updates Section 95103(o)

This change was made to ensure consistent section numbering.

Section 95104. Emissions Data Report Content and Mechanism.

This section of the reporting regulation outlines the general contents of the emissions data report, a responsible party within each reporting entity, and the method by which emissions inventory reports are conveyed.

Summary of Proposed Updates Section 95104(d)(4)

This section specifies that if a facility includes more than one cogeneration system, boiler, or steam generator, and the generated thermal energy from certain unit/system is

dedicated to certain particular end-users, the reporter must report the thermal energy disposition by unit/system so it is possible to trace the thermal energy disposition to the units dedicated to the generation. In cases where all the generated thermal energy from all the units/system within the facility boundary is provided to the same particular end-users, there is no need for separate reporting by unit/system.

Rationale for Proposed Updates Section 95104(d)(4)

This change is necessary to increase the usability of the reported data. When there are multiple particular end-users of the generated thermal energy, reporting thermal energy disposition by unit/system provides key information for calculating the cogeneration emissions attributed to electricity generation vs. thermal energy generation. This change enables the assessment of carbon cost pass-through from the cogeneration facility operator to their thermal hosts or separately from other units that are not a part of the cogeneration system.

Summary of Proposed Updates Section 95104(e)

This proposed update is to collect facility information needed to determine if there may have been the potential for emission increases in criteria pollutants or toxic air contaminants, and the reason for those potential changes.

Rationale for Proposed Updates Section 95104(e)

This qualitative data is needed to support ARB's Cap-and-Trade adaptive management monitoring, review, and analysis. The information will be used to assess the potential localized air quality impacts that may result from the Cap-and-Trade program. Collecting these data via the existing GHG reporting regulation is the most efficient mechanism for doing so.

Summary of Proposed Updates Section 95104(f)

This section was renumbered to accommodate the addition of section 95104(e).

Rationale for Proposed Updates Section 95104(f)

This change was made to ensure consistent section numbering.

Section 95105. Recordkeeping Requirements.

This section requires facilities with greater than 25,000 $MTCO_2e$ of emissions, inclusive of biomass-derived CO_2 emissions, to prepare and maintain a GHG Monitoring Plan. Maintaining a GHG Monitoring Plan helps ensure compliance and best practices, facilitate more efficient verification, and provide a consistent treatment among all the facilities at the greater than 25,000 $MTCO_2e$ emission level.

Summary of Proposed Updates Section 95105(c)

Proposed updates in this section clarify that the facility operator is responsible for completing the GHG monitoring plan and that biomass-derived carbon dioxide emissions are included in the 25,000 metric tons of CO_2e threshold determination for completing a GHG monitoring plan. This updates also requires fuel suppliers with greater than 25,000 metric tons of CO_2e to complete and maintain a GHG monitoring plan.

Rationale for Proposed Updates Section 95105(c)

This change was necessary to ensure biomass power plants and suppliers of fuel with greater than 25,000 $MTCO_2e$ of emissions maintain a GHG monitoring plan. Any facility with greater than 25,000 $MTCO_2e$ of emissions requires third-party verification, but the existing rule language was not clear whether a facility that combusts biomass fuels must also maintain a GHG Monitoring Plan similar to other facilities. Maintaining a GHG Monitoring Plan ensures compliance and best practices, facilitates more efficient verification, and provides a consistent treatment among all the facilities at the greater than 25,000 $MTCO_2e$ emission level.

Summary of Proposed Updates Section 95105(c)(7)

Added a requirement to report data associated with orifice plate inspection if AGA report No 3 (2003) Part 2 is used.

Rationale for Proposed Updates Section 95105(c)(7)

This change is necessary for consistency. Section 95103(k)(6)(A)1 allows two methods to be used for inspecting orifice plates. Due to an oversight, data associated with the inspections was only required to be reported for one of the methods. The proposed update requires data to also be reported for the second method, as described above.

Subarticle 2.

Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

Section 95110. Cement Production.

Summary of Proposed Updates Section 95110(c)

This section was updated to clarify the year of data submittal and the year of the data to be reported.

Rationale for Proposed Updates Section 95110(c)

This change was needed, in conjunction with the revision to the definition of "emissions data report," to clearly establish that an emissions data report is for the submission of required data for the calendar year prior to the year in which the report is due.

Section 95111. Electric Power Entities.

Section 95111 describes the reporting requirements for electric power entities. Electric power entities include importers, marketers, retail providers and asset controlling suppliers who are involved in electricity transactions.

Summary of Proposed Updates Section 95111(a)(4)

This section sets forth requirements for reporting imported electricity from specified sources. The proposed update would effectively require sellers of specified power to warrant or guarantee that the transacted product is, in fact, specified source electricity from the generation source along each segment in the market path. As specified in section 95103(h), the requirement that sellers warrant that the transacted product is specified source electricity would apply to 2014 data reported in 2015.

Rationale for Proposed Updates Section 95111(a)(4)

This change is necessary to ensure that specified power claims are supported by contract documentation. Clarifying language from the 2012 rulemaking process improved stakeholder understanding for claiming a specified source of electricity. However, during implementation of the changes, it was discovered that possible contracting outcomes could lead to power purchased as unspecified becoming claimed as specified. This change adds language that requires reporting entities to demonstrate that power they claim as a specified source of electricity was contracted for as a specified source throughout the market path of the power.

Summary of Proposed Updates Section 95111(a)(4)(A)

Specified source claims of imported electricity must meet certain requirements, including whether the reported amount of imported electricity was measured at the busbar. For imports measured at the busbar, use of the transmission loss factor is not required, but for power not measured at the busbar, use of the transmission loss factor is required when reporting imported power. The proposed update would clarify these provisions and require supporting documentation for busbar claims.

Rationale for Proposed Updates Section 95111(a)(4)(A)

This revision is necessary to establish a verifiable basis for busbar claims, given that busbar claims allow an electric power entity to claim a slightly smaller amount of power because the transmission loss factor is not required. Subsection headings were added to 95111(a)(4)(A)(1) and (2) for clarity and ease of reference.

Summary of Proposed Updates Section 95111(a)(5)
Text was deleted from this section and moved to section 95111(a)(5)(E)

Rationale for Proposed Updates Section 95111(a)(5)
This change was necessary to improve the consistency of the reporting requirements in this section.

Summary of Proposed Updates Section 95111(a)(5)(B)
This section sets forth requirements for reporting imported electricity supplied by asset-controlling suppliers. The proposed update would clarify the requirement for an electric power entity to report asset-controlling supplier power, that was not acquired as specified source power, as unspecified.

Rationale for Proposed Updates Section 95111(a)(5)(B)

This change is necessary to establish that asset-controlling supplier power may be reported as either specified or unspecified power depending upon the transaction, for the reason that asset-controlling supplier power can be sold in the market as either specified or unspecified power. In order to claim asset-controlling supplier power as specified, the requirements to claim a specified source of electricity must be met because a "*specified source also means electricity procured from an asset-controlling supplier recognized by the ARB*," per Section 95102(a). Asset-controlling supplier power would be claimed as unspecified power in the event that "*the source of electricity ... is not a specified source at the time of entry into the transaction to procure the electricity*," per section 95102(a). It is ARB's expectation that the ACS seller controls whether the specified ACS attributes are conveyed with the transaction. For example, a renewable energy seller determines whether the renewable energy credits (RECs) convey in a transaction for specified power. Similarly, the ACS would determine whether the specified ACS attributes convey in a transaction for specified ACS power. Thus, in order to claim specified ACS power, EPEs must provide some evidence that the ACS attributes were in fact conveyed at each point along the market path shown on the eTag.

Summary of Proposed Updates Section 95111(a)(5)(D)
This section sets forth requirements for reporting imported electricity supplied by asset-controlling suppliers. The proposed update would require an electric power entity to utilize the transmission loss factor when reporting asset-controlling supplier power.

Rationale for Proposed Updates Section 95111(a)(5)(D)

The purpose of the proposed update is to establish the requirement that all power claimed as asset-controlling supplier power must utilize the transmission loss factor of 1.02. Transmission losses in the West are usually settled financially between counterparties, and MWh values shown on e-tags are constant values throughout the various path segments on the tag, even though transmission losses have occurred during actual delivery. In addition, neither of the two asset-controlling suppliers currently registered with ARB have balancing area authority or transmission provider control points in California. While the Bonneville Power Authority (BPA) service territory

does extend into California, it does so only at the distribution level and power is only provided at that level to one entity, Surprise Valley Electric, an electric cooperative. No other electric power entities take delivery of BPA power from that portion of its service territory that extends into California. Finally, the requirement that all power claimed as asset-controlling supplier power must utilize the transmission loss factor reflects actual transmission loss associated with delivery from the asset-controlling supplier system to California.

Summary of Proposed Updates Section 95111(a)(5)(E)

The purpose of this new section is to specify the tagging requirements necessary to claim asset controlling supplier power. The proposed language would require electric power entities to ensure that the asset-controlling supplier is identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner, with the exception of path outs, where path outs are excess power, originally procured as part of a 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.

Rationale for Proposed Updates Section 95111(a)(5)(E)

The addition of this new language is necessary because not all power sold by an asset controlling supplier is, in fact, asset controlling supplier power at the approved system emission factor rate. While some asset controlling suppliers sell power from the same source as either specified or unspecified, other asset controlling suppliers sell a multitude of power products from a multitude of sources. Clear tagging requirements are one way in which more assurance can be provided to buyers and sellers about the product being transacted.

Summary of Proposed Updates Section 95111(a)(12)

The purpose of this new section is to describe the reporting requirements for system power procured from a system power supplier. The proposed language would require electric power entities to report system power volumes in a manner similar to that for asset controlling supplier power.

Rationale for Proposed Updates Section 95111(a)(12)

This change is necessary to ensure proper reporting of power imported into California that is not tagged from a specified source or is unspecified. Reporting entities would be required to report (1) the ARB identification information for the system power supplier, (2) system power as specified or unspecified as appropriate to the transaction, (3) deliveries measured at the first point of delivery in the state of California, and (4) transmission losses using the factor of 1.02 in all instances.

Summary of Proposed Updates Section 95111(b)(3)

This section sets forth the specific terms and equations for the calculation of a system emission factor for an asset-controlling supplier. The proposed update would (1) make two non-substantive grammatical changes, (2) add headers to most of the variable descriptions in the system emission factor calculation, (3) delete language consistent with the proposed update to 95111(a)(5)(B) regarding use of the transmission loss factor when reporting asset-controlling supplier power, (4) add language to the purchased electricity variable to include treaty power.

Rationale for Proposed Updates Section 95111(b)(3)

This change is necessary to clarify the asset-controlling supplier calculation method. The proposed update would delete language consistent with the proposed update to 95111(a)(5)(B) regarding the requirement for an electric power entity to utilize the transmission loss factor when reporting asset-controlling supplier power. See rationale for the 95111(a)(5)(B) proposed update for further explanation. The term "specified" was deleted from the heading as it was extraneous and now simply reads, *Calculating GHG Emissions of Imported Electricity Supplied by Specified Asset-Controlling Suppliers*. In addition, the first line of the EF_{ACS} description was modified to state that the system emission factor in this section is specific to an asset-controlling supplier.

Language was added to the purchased electricity variable PE_{sp} to include treaty power (new term in section 95102(a)). This change accounts for the fact that an asset-controlling supplier may receive power pursuant to an international treaty, like the Columbia River Treaty. When power is received by the asset-controlling supplier, the treaty power would be accounted for in the system emission factor calculation through the PE_{sp} variable.

Summary of Proposed Updates Section 95111(b)(4)

The heading to this section was italicized.

Rationale for Proposed Updates Section 95111(b)(4)

The change is necessary so this section heading is consistent with the other section headings in section 95111(b).

Summary of Proposed Updates Section 95111(b)(5)

The purpose of this new section is to add requirements to accurately reflect the carbon content of system power that is imported to California. The proposed system power language would require purchasers of system power, where system power is defined as power with a carbon content above the default emission factor, to report imported power at a system power emission factor rate calculated by ARB, instead of at the default emission factor for unspecified power.

Rationale for Proposed Updates Section 95111(b)(5)

This change is necessary to ensure the system power emission factor is calculated correctly. As currently constructed, the MRR assumes that all power tagged on the bulk transmission system is tagged at the generation facility or unit level, however, this is not always the case. Some power systems outside California do not tag power at the

generation facility or unit level but instead tag power as system power at the system level to reflect the combined output of its generation portfolio. Based on publicly available information for each system, ARB would calculate a system emission factor that reflects the weighted average contribution of all generation resources in the system portfolio. This approach will more accurately reflect the carbon content of the system power, than the use of the default emission factor for unspecified electricity imports of 0.428 MT of CO_2e/MWh, as set forth in section 95111(b)(1).

Summary of Proposed Updates Section 95111(b)(6)
This section was renumbered to account for the addition of system power in section 95111 (b)(5).

Rationale for Proposed Updates Section 95111(b)(6)
This change is necessary to ensure accurate regulatory citations.

Summary of Proposed Updates Section 95111(c)(1)
This section has been amended to correct a grammatical error – it changes "providers" to "provider."

Rationale for Proposed Updates Section 95111(c)(1)
This change is necessary to correct a grammatical error.

Summary of Proposed Updates Section 95111(f)(5)(F)

The purpose of the broader section is to set forth data requirements for the system emission factor calculation for asset-controlling suppliers. The proposed update would add a new subsection with language on the total amount of electricity received under the treaty.

Rationale for Proposed Updates Section 95111(f)(5)(F)

The proposed new subsection is needed to separately identify and incorporate treaty power into the system emission factor calculation.

Summary of Proposed Updates Section 95111(f)(5)(G)

The purpose of this change is to renumber this section due to the above section changes.

Rationale for Proposed Updates Section 95111(f)(5)(G)

This change is necessary to ensure consistency in the reporting regulation.

Summary of Proposed Updates Section 95111(g)
The purpose of this change is to set forth certain requirements for specified source and RPS Adjustment claims. The proposed update would add language for the registration of anticipated system power supplier resources and update a section reference.

Rationale for Proposed Updates Section 95111(g)

This change is necessary to establish July 1 prior to each data year for the registration of system power supplier resources. For example, an electric power entity registers anticipated system power sources by July 1, 2014. ARB will then use the information submitted pursuant to section 95111(g)(6) to calculate an emission factor for use with 2015 data reported in 2016.

Summary of Proposed Updates Section 95111(g)(1)(N)

The purpose of this section is to require retention of generation meter data by the electric power entity for verification purposes to avoid the over-accounting low-emission generation.

Rationale for Proposed Updates Section 95111(g)(1)(N)

This change is necessary to clarify the reporting requirements for meter generation retention. It is ARB's understanding that it is common practice in the industry to perform monthly true-ups between generated and scheduled power.

Summary of Proposed Updates Section 95111(g)(6)

The purpose of this section is to set forth registration requirements for system power supplier sources. The proposed update would add language for the registration of anticipated system power supplier resources, pursuant to the broader section 95111(g). Registrants would be required to provide information on, the proposed system power supplier, a description of the system as well as the publicly available information which ARB might utilize in a system emission factor calculation, and provide information on current and historical NAESB/NERC e-tagging practices for the system power supplier.

Rationale for Proposed Updates Section 95111(g)(6)

This change is necessary to establish the reporting requirements needed by the July 1 registration deadline indicated in section 95111(g).

Section 95112. Electricity Generation and Cogeneration Units.

This section details reporting requirements for electricity generation and cogeneration units.

Summary of Proposed Updates Section 95112(a)

Rule language added to indicate that facility operators who are applying for the legacy contract generator transition assistance under the Cap-and-Trade regulation must always report the information in section 95112(a)(4)-(6), even if they do not provide or sell any generated energy outside of the facility boundary.

Rationale for Proposed Updates Section 95112(a)

This change is necessary to ensure that ARB will have sufficient energy disposition data for implementing the legacy contract generator transition assistance provision in the Cap-and-Trade regulation.

Summary of Proposed Updates Section 95112(a)(4)

A heading is added to each of the electricity disposition items in paragraphs 95112(a)(4)(A), (B), and (C). Also, new rule language is added to the end of section 95112(a)(4) to require certain breakout of electricity dispositions under the following situation: If a facility includes more than one electricity generating unit or cogeneration system, and the generated electricity from certain unit/system is dedicated to certain particular end-users, retail providers, or electricity marketer, the reporter must report the electricity disposition by unit/system so it is possible to trace the electricity disposition to the units dedicated to the generation. However, if all the generated electricity from all the units/system within the facility boundary is provided to the same particular end-users, retail providers, or electricity marketer, there is no need breakout the disposition by unit/system.

Rationale for Proposed Updates Section 95112(a)(4)

Many reporters have either entered the energy disposition in the incorrect data fields in the reporting tool, or selected the incorrect energy flows from their system energy diagram to match the items specified in paragraphs 95112(a)(4)(A), (B), and (C). The headings are added to these paragraphs for clarification to assist reporters identify the correct energy flows to report under these energy disposition items.

When a facility provides generated electricity to multiple particular end-users, retail provider, or electricity marketer, the electricity disposition information by unit/system provides key information for assessing carbon cost pass-through from the electricity generator to the purchasers of the generated electricity.

Summary of Proposed Updates Section 95112(a)(4)(C)

A new requirement is added to paragraph 95112(a)(4)(C): if some of the generated electricity is used to produce cooling energy for a customer outside of its facility boundary or for on-site industrial processes or operations that are neither in support of nor a part of the power generation system, the facility operator must report the amount of generated electricity used for producing the cooling energy. This requirement does not apply if the sole purpose of the generated cooling energy is for maintaining temperature in the electricity generation or cogeneration system.

Rationale for Proposed Updates Section 95112(a)(4)(C)

This change is necessary to clarify how the reporter of such a facility type should account for the generated electricity used for producing cooling energy for applications not related to electricity generation. This new requirement helps the affected reporting entities complete their system energy balance.

Summary of Proposed Updates Section 95112(a)(5)

This proposed amendment introduces the term "generated thermal energy," which is mentioned throughout section 95112(a)(5). A heading is added to each of the thermal energy disposition items in paragraphs 95112(a)(5)(A), (B), and (C). Also, new rule language is added to the end of sub-section 95112(a)(5) to require certain breakout of thermal energy dispositions under the following situation: if a facility includes more than one cogeneration or bigeneration unit/system, and the generated thermal energy from certain unit/system is dedicated to certain particular end-users, the reporter must report the thermal energy disposition by unit/system so it is possible to trace the thermal energy disposition to the units dedicated to the generation. However, if all the generated thermal energy from all the units/system within the facility boundary is provided to the same particular end-users, there is no need breakout the disposition by unit/system.

Rationale for Proposed Updates Section 95112(a)(5)

Many reporters have either entered the energy disposition in the incorrect data fields in the reporting tool, or selected the incorrect energy flows from their system energy diagram to match the items specified in paragraphs 95112(a)(5)(A), (B), and (C). The headings are added to these paragraphs for clarification to assist reporters identify the correct energy flows to report under these energy disposition items.

When a facility provides generated thermal energy to multiple particular end-users, the thermal energy disposition information by unit/system provides key information for assessing carbon cost pass-through from the generator to the purchasers of the thermal energy.

Summary of Proposed Updates Section 95112(a)(5)(C)

A new requirement is added to paragraph 95112(a)(5)(C): if some of the generated thermal energy is used to produce cooling energy or distilled water for a customer outside of its facility boundary or for on-site industrial processes or operations that are neither in support of nor a part of the power generation system, the facility operator must report the amount of generated thermal energy used for producing the cooling energy or distilled water. This requirement does not apply if the sole purpose of the generated cooling energy is for maintaining temperature in the electricity generation or cogeneration system.

Rationale for Proposed Updates Section 95112(a)(5)(C)

This change is necessary to clarify how the reporter of such facility should account for the generated thermal energy used for producing distilled water or for producing cooling energy for applications not related to electricity generation or cogeneration. This new requirement helps the affected reporting entities complete their system energy balance.

Summary of Proposed Updates Section 95112(a)(6)

Removed reference to historical data year.

Rationale for Proposed Updates Section 95122(a)(6)

References to historical data years have been removed.

Summary of Proposed Updates Section 95112(b)(2)

Staff has added clarifications to describe that the difference between net generation and gross generation is the parasitic load of electricity generation or cogeneration, and the net generation quantity represents the amount of generated electricity that can be provided to the disposition categories in section 95112(a)(4).

Rationale for Proposed Updates Section 95112(b)(2)

This change was made in response to reporter and verifier questions received during program implementation.

Summary of Proposed Updates Section 95112(b)(3)

Staff has added clarifications that total thermal output is the thermal energy generated by the cogeneration or bigeneration system that can be potentially utilized in other industrial operations that are not related to electricity generation. Also clarify that the total thermal output quantity represents the amount of generated thermal energy that can be provided to the disposition categories in section 95112(a)(5).

Rationale for Proposed Updates Section 95112(b)(3)

This change was made in response to reporter and verifier questions received during program implementation.

Summary of Proposed Updates Section 95112(c)

Staff has added sorbent emissions to the heading of this section.

Rationale for Proposed Updates Section 95112(c)

This change is necessary to include sorbent emissions as part of this section in conjunction with the addition of section 95112(c)(3).

Summary of Proposed Updates Section 95112(c)(3)

Staff has added a requirement for operators of a Subpart D unit to report the portion of the reported CO_2 emissions attributed to sorbent.

Rationale for Proposed Updates Section 95112(c)(3)

This change was made to support the calculation of the state-wide greenhouse gas emission inventory.

Summary of Proposed Updates Section 95112(f)

Staff has deleted the phrase "produce hydrogen on-site" and the phrase that limits reporting to "fuels or feedstocks used in hydrogen production" from the introduction paragraph.

Rationale for Proposed Updates Section 95112(f)

This change was necessary to support revised language in conjunction with the addition of paragraph 95112(f)(5).

Summary of Proposed Updates Section 95112(f)(5)

Staff has added a reporting requirement and emission calculation methods for hydrogen fuel cell units.

Rationale for Proposed Updates Section 95112(f)(5)

This change was made to inform the state-wide greenhouse gas inventory of electricity generation emissions and to help ARB monitor the growth in hydrogen fuel cell installations.

Summary of Proposed Updates Section 95112(h)

Removed reference to historical data.

Rationale for Proposed Updates Section 95112(h)

For consistency, removed reference to historical data years.

Section 95113. Petroleum Refineries.

This section defines the reporting requirements for hydrogen production facilities.

Summary of Proposed Updates Section 95113

Updates in this section require operators of petroleum refineries who report both facility emissions and supplied transportation fuels emissions under the same ARB ID, to report each emissions component (refinery and supplier) under a separate ARB ID.

Rationale for Proposed Updates Section 95113

This change was necessary to ensure that the refinery emissions subject to a compliance obligation starting in the first compliance period are reported and verified separately from the fuel supplier emissions that are subject to a compliance obligation starting with the second compliance period.

Summary of Proposed Updates Section 95113(k)

Text relating to historical data submissions has been deleted.

Rationale for Proposed Updates Section 95113(k)

Requirements relating to historical data are no longer applicable.

Summary of Proposed Updates Section 95113(l)(1)

Staff added text discussing the verification requirements of primary refinery product data for present and future data reports.

Rationale for Proposed Updates Section 95113(l)(1)

This new text clarifies the verification requirements for primary refinery products for present and future emission data report submittals.

Summary of Proposed Updates Section 95113(l)(1)(A)

Historical voluntary data reporting requirements for the reporting of calcined coke product data have been deleted.

Rationale for Proposed Updates Section 95113(l)(1)(A)

These historical product data reporting requirements are no longer required. However the mandatory reporting of this product data type is still required to support the Cap-and-Trade program and is listed in section 95113(l)(1).

Summary of Proposed Updates Section 95113(l)(2)

Added text ensures the operator demonstrates conformance to the verifier that the Solomon EII value is correct.

Rationale for Proposed Updates Section 95113(l)(2)

This addition is required to ensure that the facility Solomon EII value is correctly reported and verified.

Summary of Proposed Updates Section 95113(l)(3)(A)

Historical references to prior reporting years have been deleted. Text defining CWT data as covered product data has been added.

Rationale for Proposed Updates Section 95113(l)(3)(A)

References to historical data reporting are no longer needed. Verification requirements for CWT are delineated and clarified.

Summary of Proposed Updates Section 95113(l)(3)(C)(1-4)

This section was renumbered.

Rationale for Proposed Updates Section 95113(l)(3)(C)(1-4)

For consistency with the rest of the reporting regulation, this section was renumbered.

Summary of Proposed Updates Section 95113(l)(3)(D)

A requirement was added to annually determine the density of each CWT throughput. This requirement allows the use of default densities for each material, but if a default value is not available, a measurement must take place.

Rationale for Proposed Updates Section 95113(l)(3)(D)

This change is necessary to convert the barrels of material to mass units. Density measurements are required to covert each throughput value from a barrel basis to mass units.

Summary of Proposed Updates Section 95113(l)(4)

This section adds reporting requirements for complexity weighted barrel, a covered product data. The section outlines the reporting requirements and the equation used to calculate the overall complexity weighted barrel for each refinery.

Rationale for Proposed Updates Section 95113(l)(4)

This change is necessary to ensure refiners can report using the complexity weighted barrel throughputs beginning with the second compliance period of the Cap-and-Trade program..

Summary of Proposed Updates Section 95113(l) – Table 1

The term "CWT" was deleted from the title of the Table and the column headings.

Rationale for Proposed Updates Section 95113(l) – Table 1

This change is necessary for the Table to apply to both the carbon dioxide weighted tonne and complexity weighted barrel.

Section 95114. Hydrogen Production.

This section defines the reporting requirements for hydrogen production facilities.

Summary of Proposed Updates Section 95114(a)

Text has been added to require emissions reporting for hydrogen production facilities which may not sell hydrogen but consume all produced hydrogen on-site (e.g., an R&D facility).

Rationale for Proposed Updates Section 95114(a)

This change is necessary to ensure that all hydrogen producers with emissions exceeding the reporting threshold will report their emissions to ARB.

Summary of Proposed Updates Section 95114(e)

This section has been modified to require the reporting of feedstock carbon and hydrogen content, regardless of measurement method (CEMS or non-CEMS).

Rationale for Proposed Updates Section 95114(e)

This change is necessary to support the development of an accurate statewide greenhouse gas inventory. The inventory tracks emissions such as process emissions and stationary combustion fuel emissions separately. Hydrogen content data, along with carbon content data, is necessary to delineate emissions from the on-purpose production of hydrogen and will facilitate separation of combustion and process emissions necessary for the GHG inventory.

Summary of Proposed Updates Section 95114(e)(1)

This section has been added to set-forth the sampling frequencies requirements for the determination of feedstock carbon and hydrogen content at all CEMS equipped facilities.

Rationale for Proposed Updates Section 95114(e)(1)

This change is necessary to indicate the sampling frequency for the carbon and hydrogen content of all feedstock. The change supports the development of an accurate GHG inventory of combustion and process emissions related to the production of hydrogen.

Summary of Proposed Updates Section 95114(e)(1)(A) – (C)

These three sections have been modified to provide procedures for determination of the carbon and hydrogen content for solid, liquid, and gaseous feedstocks for all reporters.

Rationale for Proposed Updates Section 95114(e)(1)(A) – (C)

This change is necessary to provide reporters with the details for determination of the carbon and hydrogen contents for all solid, liquid, and gaseous feedstocks.

Summary of Proposed Updates Section 95114(e)(2)

This section has been modified to set-forth sampling frequencies for the determination of fuel and feedstock carbon content and molecular weight at facilities not equipped with a CEMS for gaseous, liquid and solid feedstock.

Rationale for Proposed Updates Section 95114(e)(2)

This change is necessary to clarify the sampling frequencies at facilities not equipped with CEMS. The requirements for this section are not new, but renumbered to accommodate the new carbon and hydrogen content reporting requirements described in section 95114(e)(1).

Summary of Proposed Updates Section 95114(g)

This change requires that reporters report the mass of CO_2 resulting from hydrogen production reported elsewhere in the MRR (e.g. as flaring or combustion emissions or transferred CO_2) and subsequently subtract these emissions from their facility total to avoid double-counting.

Rationale for Proposed Updates Section 95114(g)

This change is necessary to ensure correct emissions reporting, data consistency and avoid double counting of emissions.

Summary of Proposed Updates Section 95114(i)

This change requires subtraction of the mass of all transferred carbon dioxide (reported under section 95123 as a supplier of carbon dioxide) from the facility emissions.

Rationale for Proposed Updates Section 95114(i)

This change is necessary to ensure correct emissions reporting, data consistency and avoid double counting of emissions.

Summary of Proposed Updates Section 95114(j)

These changes require reporting of the mass of both on-purpose and by-product hydrogen produced at the facility as well as the amount of hydrogen produced and the amount of liquid hydrogen sold.

Rationale for Proposed Updates section 95114(j)

This change is necessary to support the allocation of allowances under the Cap-and-Trade program and for the statewide GHG inventory to assign the correct emissions to the on-purpose production of hydrogen.

Summary of Proposed Updates Section 95114(k)

Staff proposed language requiring the calculation of CH_4 and N_2O emissions resulting from fuel combustion.

Rationale for Proposed Updates Section 95114(k)

This change is necessary to ensure more accurate and complete emission reporting. Previously, emissions of CH_4 and N_2O from stationary fuel combustion were not reported.

Summary of Proposed Updates Section 95114(l)

This subsection has been added to the hydrogen production emissions reporting requirements. This new language requires that reporters determine the CO_2, CH_4, and N_2O emission from all flaring operations at their facility.

Rationale for Proposed Updates Section 95114(l)

This new language restores a previous reporting requirement that was part of an earlier version of the reporting regulation. By harmonizing with U.S.EPA these emissions were inadvertently removed from the reporting regulation. The reporting of flaring emissions that are associated with hydrogen production will provide a more accurate accounting of emissions for both the GHG statewide inventory and the Cap-and-Trade program.

Section 95115. Stationary Combustion Sources.

Summary of Proposed Updates Section 95115(c)(1)

Updates in this section allow operators to use Tier 1 or Tier 2 methods for biomass-derived fuels that are mixed prior to combustion with fossil fuels.

Rationale for Proposed Updates Section 95115(c)(1)

This change is necessary to increase the flexibility for operators to choose the Tier 1 and Tier 2 methods for biomass and fossil fuel streams mixed prior to combustion, acknowledging that the accuracy of the emissions estimate should not be affected as long as fuel consumption measurements meet the relevant accuracy requirements specified in 95103(k) and 40 CFR §98.3(i).

Summary of Proposed Updates Section 95115(c)(4)

Updated language to remove a typographical error.

Rationale for Proposed Updates Section 95115(c)(4)

This change is necessary to correct a typographical error.

Summary of Proposed Updates Section 95115(e)

Proposed updates specify that the procedure outlined in this section is required for calculating emissions from biomass fuel sources such as municipal solid waste (MSW), that are inherently intermixed with fossil fuels.

Rationale for Proposed Updates Section 95115(e)

This revision was made to provide further clarity on applicability of the procedure described in the section. The change also clarifies that there is no intended 'mixing' step in the process that must be performed by the operator.

Summary of Proposed Updates Section 95115(h)

Staff has amended this provision to require the reporting by unit type from heat input (MMBtu) to percentage of the aggregated fuel consumption.

Rationale for Proposed Updates Section 95115(h)

The update is made for consistency with the current reporting tool implementation. With the existing requirement to report the total fuel input in MMBtu for each unit configuration, the data requirement for reporting heat input is the same as reporting the percentage of the aggregated fuel.

Summary of Proposed Updates Section 95115(k)

Language was updated to replace the term natural gas "provider" with natural gas "supplier." Language was also added that clarifies that facility operators must report their natural gas supplier's customer account or service identification number(s) for the facility. Lastly, language was added concerning natural gas purchases from entities other than the natural gas supplier. The supplier is the entity that owns/operates the pipelines that physically deliver the gas to the facility, and may or may not be the entity that is selling the gas to the facility.

Rationale for Proposed Updates Section 95115(k)

This change is necessary to clarify that operators who report combustion emissions are required to identify and report the name of the facility's natural gas 'supplier' and the facility's customer account or service identification number for that supplier.

Summary of Proposed Updates Section 95115(l)

Proposed language was added to require operators who report combustion emissions to indicate whether any of the gas reported pursuant to section 95115(k) was supplied to downstream users outside of the operator's facility boundary. Any such instances must be reported, and the operator must report the name of the downstream end user and the MMBtu of the gas delivered.

Rationale for Proposed Updates Section 95115(l)

This subsection was added to ensure that ARB can accurately quantify each natural gas supplier's compliance obligation.

Summary of Proposed Updates Section 95115(m)

Removed reference to historical data and renumbered.

Rationale for Proposed Updates Section 95115(m)

This change was made to ensure the regulatory text was consistent with the updated definition of emissions data report and correct numbering.

Summary of Proposed Updates Section 95115(n)(5-17)

Proposed new language in this section includes the reporting of product data for additional industrial sectors. This includes mainly additions to the food processing sector, such as dairies, tomato processors, etc.

Rationale for Proposed Updates Section 95115(n)(5-17)

Reporting of product data for additional industry sectors is necessary to support the ARB Cap-and-Trade program. Specifically, the reported product data are used to assign free allocations for the purpose of leakage prevention and provide a benefit to the affected industries.

Section 95116. Glass Production.

Summary of Proposed Updates Section 95116(c)

References to historical data years have been removed.

Rationale for Proposed Updates Section 95116(c)

This change was made to ensure the regulatory text was consistent with the updated definition of emissions data report.

Section 95117. Lime Manufacturing.

Summary of Proposed Updates Section 95117(c)

Removed reference to historical data.

Rationale for Proposed Updates Section 95117(c)

This change was made to ensure the regulatory text was consistent with the updated definition of emissions data report.

Summary of Proposed Updates Section 95117(c)(2)(A)

Proposed additions in this section specify that missing data must be based on all available process data for that report year.

Rationale for Proposed Updates Section 95115(c)(2)(A)

This update clarifies that only process data from that report year can be used for determining the value of missing data.

Summary of Proposed Updates Section 95117(c)(3)

Section added to indicate that the missing data requirements only apply to data used for reporting emissions, not for product data.

Rationale for Proposed Updates Section 95117(c)(3)

Added for clarification on the use of missing data requirements.

Summary of Proposed Updates Section 95117(e)

The reporting requirements for lime production were modified to include the calculation of CO_2 used and reabsorbed onsite.

Rationale for Proposed Updates Section 95117(e)

For some industrial sectors that produce lime, such as sugar production, the CO_2 produced during the lime production is reintroduced into the manufacturing process, reabsorbed, and is not released to the atmosphere. This regulatory update requires reporting of the produced emissions that are not released to the atmosphere. This allows the captured emissions to be subtracted from the total reported CO_2 produced, providing an accurate accounting of the actual CO_2 emissions released to the atmosphere.

Section 95118. Nitric Acid Production.

Summary of Proposed Updates Section 95118(a)

This update corrects a clerical error in the citation of 40 CFR Part 98.

Rationale for Proposed Updates Section 95118(a)

This change is necessary to correct an incorrect citation.

Summary of Proposed Updates Section 95118(c)

Removed language in conjunction with update of the emissions data report definition.

Rationale for Proposed Updates Section 95118(c)

The updated definition for emissions data report rendered the removed language in this section obsolete.

Summary of Proposed Updates Section 95118(c)(2)

Added language in this section specifies that missing data substitution is allowed only for emissions data, not product data.

Rationale for Proposed Updates Section 95118(c)(2)

Language in this section was added to clarify its original intent.

Section 95119. Pulp and Paper Manufacturing

Summary of Proposed Updates Section 95119(c)

Removed language in conjunction with update of the emissions data report definition.

Rationale for Proposed Updates Section 95119(c)

The updated definition for emissions data report rendered the removed language in this section obsolete.

Summary of Proposed Updates Section 95119(d)

Included additional specifications for the reporting of tissue production.

Rationale for Proposed Updates Section 95119(d)

The update was needed to provide more specific and standardized information regarding tissue production.

Section 95120. Iron and Steel Production

Summary of Proposed Updates Section 95120(c)

Removed language in conjunction with update of the emissions data report definition.

Rationale for Proposed Updates Section 95120(c)

The updated definition for emissions data report rendered the removed language in this section obsolete.

Section 95121. Suppliers of Transportation Fuels.

Summary of Proposed Updates Section 95121(a)(2)

Language was inserted to specify that fuels used exclusively for aviation or marine applications are not considered transportation fuels, for the purposes of this article.

Rationale for Proposed Updates Section 95121(a)(2)

This language was added to clarify which fuels are required to be reported as transportation fuels per section 95121.

Section 95122. Suppliers of Natural Gas, Natural Gas Liquids, Liquefied Petroleum Gas, Compressed Natural Gas and Liquefied Natural Gas.

Section 95122 provides GHG reporting and calculation requirements for suppliers of natural gas, natural gas liquids, and liquefied petroleum gas. Section 95122 is applicable to local distribution companies (LDCs), interstate and intrastate pipeline operators, natural gas liquid fractionators, and consignees of liquefied petroleum gas, compressed natural gas, and liquefied natural gas.

Summary of Proposed Updates Section 95122(a)(2)

Updates included added language regarding intrastate pipelines, and the term 'provided' was changed to 'delivered.'

Rationale for Proposed Updates Section 95122(a)(2)

This change is necessary to identify that intrastate pipelines delivering gas to end-users are considered LDCs and that the natural gas suppliers must report all gas delivered, rather than sold, to entities on their distribution pipeline.

Summary of Proposed Updates Section 95122(a)(3)

The word "imported" was added to this paragraph to indicate that consignees should report only imported liquefied petroleum gas, compressed natural gas (CNG), and liquefied natural gas (LNG).

Rationale for Proposed Updates Section 95122(a)(3)

This change is necessary to clarify language in this section to specify the original intent of the article.

Summary of Proposed Updates Section 95122(a)(4)

Subparagraph 4 was added to 95122(a) that requires liquefied natural gas production facilities that are required to report GHG emissions per 95101(c)(10) to report emissions of CO_2, CH_4, and N_2O from all LNG delivered or sold to others, unless a final destination outside California can be demonstrated.

Rationale for Proposed Updates Section 95122(a)(4)

This language was added to ensure complete and consistent reporting of GHG emissions for all natural gas that is supplied within California.

Summary of Proposed Updates Section 95122(b)(2)

Language was added to this section that refers to the natural gas emission calculation equation specified in section 95122(b)(6).

Rationale for Proposed Updates Section 95122(b)(2)

This change is necessary to provide additional clarity regarding the data that must be used to calculate the CO_2i input parameters required in 95122(b)(6). This revision ensures consistency of reporting.

Summary of Proposed Updates Section 95122(b)(3)

Language was added to this section that refers to the natural gas emission calculation equation specified in section 95122(b)(6). Additional language was added requiring publicly owned natural gas utilities to follow the procedures in the paragraph.

Rationale for Proposed Updates Section 95122(b)(3)

This change is necessary to provide additional clarity regarding the data that must be used to calculate the CO_2j input parameters required in 95122(b)(6). This revision provides additional clarity regarding the data that must be used to calculate the CO_2j input parameters required in 95122(b)(6), and ensures that publicly owned natural gas utilities are required to calculate a CO_2j parameter. These revisions ensure consistency of reporting.

Summary of Proposed Updates Section 95122(b)(4)

Language was added to this section that refers to the natural gas emission calculation equation specified in section 95122(b)(6).

Rationale for Proposed Updates Section 95122(b)(4)

This change is necessary to provide additional clarity regarding the data that must be used to calculate the CO_2l input parameters required in 95122(b)(6). This revision ensures consistency of reporting.

Summary of Proposed Updates Section 95122(b)(6)

Language was added to this section that refers back to the subparagraphs (2),(3), and (4) of section 95122(b).

Rationale for Proposed Updates Section 95122(b)(6)

This change is necessary to provide additional clarity regarding the data that is necessary to determine the parameters CO_2i, CO_2j, and CO_2l in the natural gas emission calculation equation specified in this section.

Summary of Proposed Updates Section 95122(b)(9)

Language was added regarding reporting requirements for imported CNG and LNG.

Rationale for Proposed Updates Section 95122(b)(9)

This revision increases the clarity of the requirements for California consignees, and ensures consistent reporting of imported CNG and LNG.

Summary of Proposed Updates Section 95122(b)(10)

The term 'imported' was added to this section.

Rationale for Proposed Updates Section 95122(b)(10)

This revision clarifies that requirements in the section are applicable only to imported CNG/LNG. This ensures consistent reporting of CNG and LNG.

Summary of Proposed Updates Section 95122(b)(11)

Updates to this section add requirements for reporting of CO_2 emissions from LNG produced at production facilities that are required to report GHG emissions per section 95101(c)(10).

Rationale for Proposed Updates Section 95122(b)(11)

This change is necessary to provide a CO_2 emissions quantification method for LNG facilities that are required to report GHG emissions. This addition ensures there are no gaps in reporting CO_2 emissions from natural gas supplied in California.

Summary of Proposed Updates Section 95122(b)(12)

Updates to this section provide requirements for reporting of CH_4 and N_2O from LNG produced at production facilities required to report emissions per section 95101(c)(10).

Rationale for Proposed Updates Section 95122(b)(12)

This change is necessary to provide a CH_4 and N_2O emissions quantification method for LNG facilities that are require to report GHG emissions per section 95101(c)(10). This addition ensures there are no gaps in reporting CH_4 and N_2O emissions from natural gas supplied in California.

Summary of Proposed Updates Section 95122(b)(13)

This section is renumbered due to the addition of the sections above.

Rationale for Proposed Updates Section 95122(b)(12)

This change is necessary to ensure consistent reporting.

Summary of Proposed Updates Section 95122(d)(2)(D)

This revision requires all LDCs to report the annual gas quantity and receiving entity's name for each delivery of natural gas to other LDCs or interstate pipelines.

Rationale for Proposed Updates Section 95122(d)(2)(D)

This change is necessary to increase the transparency of natural gas suppliers' reported 'redeliveries' of natural gas. This information facilitates accurate calculation of each natural gas supplier's compliance obligation, and helps verifiers determine conformance with the emissions calculation procedures for natural gas suppliers.

Summary of Proposed Updates Section 95122(d)(2)(E)

Proposed updates will require LDCs to report the annual gas quantity, customer information, and ARB ID (if available) for all deliveries to end-users registering greater than 188,500 MMBtu. This revision also lowers the threshold for reporting end-user information from ~25,000 metric tons CO_2e of gas delivered to ~10,000 metric tons CO_2e of gas delivered.

Rationale for Proposed Updates Section 95122(d)(2)(E)

This change is necessary to facilitate a more accurate calculation of each natural gas supplier's compliance obligation. Previously, the threshold was only at ~25,000 metric tons CO2e, which does not completely account for all of the covered entities that need to be considered during the covered emissions calculation.

Summary of Proposed Updates Section 95122(d)(4)

Language was updated with regards to intrastate pipeline reporting requirements, specifying that when intrastate pipelines are required to report data, and allowing intrastate pipelines to subtract off gas quantities that are 'redelivered' to downstream LDCs or pipelines.

Rationale for Proposed Updates Section 95122(d)(4)

This change is necessary to clarify intrastate reporting requirements and enable more accurate reporting. The previous reporting requirements for intrastate pipelines were inconsistent with the requirements for other LDC categories.

Summary of Proposed Updates Section 95122(d)(5)

Proposed additions to this section require LNG production facilities required to report emissions per section 95101(c)(10) to report the annual quantity of LNG 'delivered and sold' in MMBtu.

Rationale for Proposed Updates Section 95122(d)(5)

This change is necessary to ensure LNG production facilities that are required to report GHG emissions are required to report relevant LNG delivery data.

Summary of Proposed Updates Section 95122(d)(6)

New language added to this section requires all LDCs that report exempt biomass emission from biomethane, to report the biomethane procurement information specified in section 95103(j).

Rationale for Proposed Updates Section 95122(d)(6)

This change is necessary to ensure that the supplier has the requisite data available for meeting the biomethane verification requirements in section 95131(i) and the requirements of section 95852.1.1 of the Cap-and-Trade regulation. This subparagraph was added to require local distribution companies that purchase and deliver biomethane on behalf of their end-users to report the necessary biomethane procurement information specified in section 95103(j).

Section 95123. Suppliers of Carbon Dioxide

Summary of Proposed Updates Section 95123(b)

Removed language in conjunction with update of the emissions data report definition.

Rationale for Proposed Updates Section 95123(b)

The updated definition for emissions data report rendered the removed language in this section obsolete.

Section 95124. Lead Production.

Summary of Proposed Updates Section 95124

Proposed update requires California facilities producing lead to report their process CO_2 emissions. This also includes requirements to report lead production data, missing data procedures, CO_2 combustion, and monitoring requirements.

Rationale for Proposed Updates Section 95124

Process emissions from lead facilities were not included in the previous GHG reporting regulations due to a lack of identified lead production facilities. ARB staff has identified operational lead production facilities in California and this update provides equitable reporting of process emissions across industry sectors that produce process emissions. Those subject to the new requirement already report the specified data under the U.S. EPA greenhouse gas reporting rule. Reporting of product data for the lead production sector is necessary to support the Cap-and-Trade program. Specifically, the reported product data are used to assign allowance allocations for the purpose of leakage prevention and provide a benefit to the affected facilities.

Subarticle 3. Additional Requirements for Reported Data

Section 95129. Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

Summary of Proposed Updates Section 95129(c)(3)

Staff has changed "emissions from a source" to "a fuel characteristic data element."

Rationale for Proposed Updates Section 95129(c)(3)

The change is necessary to clarify reporter and verifier questions received during program implementation.

Summary of Proposed Updates Section 95129(c)(3)(Table 1)

Proposed language in this section adds a default carbon content of 90 percent for other liquid or gaseous fuels, and a default carbon content of 100% for solid fuels not previously listed in Table 1 of section 95112(c)(3).

Rationale for Proposed Updates Section 95129(c)(3)(Table 1)

The addition of a default carbon content for other solid, liquid, or gaseous fuels not previously listed in the table gives reporters a simplifying option to substitute missing carbon content with a conservative high number if historical company records pursuant to paragraph 95129(c)(3)(B) are not available. The reporters who choose this option would be reporting an overestimation of emissions in exchange for the simplifying approach. A higher default carbon content for solid fuels is being proposed because some fuels used in California exceed 90% carbon on a mass basis.

Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

Section 95130. Requirements for Verification of Emissions Data Reports.

Summary of Proposed Updates Section 95130(a)(1)(D)

Updated language no longer requires full verification services in the event of a change in ownership the prior year. Instead, the update requires full verification services when a change in operational control occurs during the data collection year subject to verification or during the following year prior to the conclusion of verification services.

Rationale for Proposed Updates Section 95130(a)(1)(D)

This change is necessary to address the need to require full verification services during change of operational control, due to the higher risk of errors that may occur from a change in management.

Summary of Proposed Updates Section 95130(a)(2)

The proposed change includes more types of third-party verifications in determining the time allowed for ARB verification services. Types of third-party verifications include verification services conducted under this article, third-party certification of environmental management systems under ISO 14001 standards or energy management systems under ISO 50001, and other verifications conducted in accordance with, or equivalent to, section 95133. The six year limit is only applicable to any third-party verifications that include the scope of activities under the ARB identification number for the emissions data report. The six year limitation on any third-party verification services does not reset upon a change in reporting entity ownership or operational control. The update also clarifies the beginning and end dates that establish the six year limitation.

Rationale for Proposed Updates Section 95130(a)(2)

The change is necessary to clarify the six year limitation, a condition for maintaining verifier independence, which applies to conducting ARB verification services.

Section 95131. Requirements for Verification Services.

Summary of Proposed Updates Section 95131(a)(2)(C)

The proposed change indicates that lead production requires a process specialist accreditation in order to perform verification services.

Rationale for Proposed Updates Section 95131(a)(2)(C)

This change is necessary to ensure consistency in the accreditation of process emission specialists as verifiers.

Summary of Proposed Updates Section 95131(b)(8)(A),(B)

The proposed language adds section 95158 of the reporting regulation, which was added to the mandatory reporting regulation in 2012.

Rationale for Proposed Updates Section 95131(b)(8)(A),(B)

Section 95158 was added to the mandatory reporting regulation in 2012, but previously not included in this section. This additional language corrects that oversight.

Summary of Proposed Updates Section 95131(b)(8)(D)

Proposed updates in this section separate the requirements for data checks to determine reasonable assurance of no material misstatement, from data checks to determine reasonable assurance of conformance. The proposed update also specifies that covered emissions and covered product data are evaluated for material misstatement.

Rationale for Proposed Updates Section 95131(b)(8)(D)

This change is necessary to separate the requirements for data checks to determine reasonable assurance of no material misstatement from data checks to determine reasonable assurance of conformance. The proposed also specifies that it is "covered" emissions and "covered" product data that are evaluated for material misstatement.

Summary of Proposed Updates Section 95131(b)(8)(F)

This proposed update acknowledges that verifiers use data checks to assess reasonable assurance of reporting entity conformance with the mandatory reporting regulation requirements and specifies that specific regulatory requirements must be included in the risk assessment for conformance review.

Rationale for Proposed Updates Section 95131(b)(8)(F)

This change is necessary to clarify that specific mandatory reporting requirements must be included in the risk assessment for conformance review, because the importance of this data is not otherwise made clear relative to other regulatory provisions.

Summary of Proposed Updates Section 95131(b)(8)(F)(1)

The proposed change makes explicit the requirement for verifiers to review the accuracy of the natural gas MMBtu reported under section 95115(k) by facilities that combust natural gas.

Rationale for Proposed Updates Section 95131(b)(8)(F)(1)

This change is necessary to ensure the volumes reported by the natural gas suppliers are accurate for the purposes of calculating a compliance obligation for natural gas suppliers.

Summary of Proposed Updates Section 95131(b)(8)(F)(2)

The proposed change makes explicit the requirement for verifiers to review the accuracy of end-users deliveries reported under section 95122(d)(4) by natural gas local distribution companies.

Rationale for Proposed Updates Section 95131(b)(8)(F)(2)

This change is necessary to ensure end-user information provided by natural gas suppliers is accurate for purposes of calculating a compliance obligation for natural gas suppliers.

Summary of Proposed Updates Section 95131(b)(8)(F)(3)

The proposed change makes explicit the requirement for verifiers to review the electricity provider information, reported under section 95104(d)(1).

Rationale for Proposed Updates Section 95131(b)(8)(F)(3)

This change is necessary to ensure accurate values are reported, which are used in the greenhouse gas inventory data.

Summary of Proposed Updates Section 95131(b)(8)(G)

Renumbered from F to accommodate new section.

Rationale for Proposed Updates Section 95131(b)(8)(G)

Renumbered to accommodate new section.

Summary of Proposed Updates Section 95131(b)(9)

Proposed updates clarify that correctable errors in reported covered and non-covered emissions, or in supporting parameters used in emissions calculations, must be fixed. The update also requires that correctable errors in reported covered product data must be fixed. Verifiers must use professional judgment to determine whether a discrepancy is a correctable error as defined pursuant to the proposed definition of correctable errors. Additionally, the source of the discrepancy must be documented by the verifier.

Rationale for Proposed Updates Section 95131(b)(9)

This change is necessary based on experience gained during implementation of the reporting regulation in prior years.

Summary of Proposed Updates Section 95131(b)(12)(B)

The proposed change clarifies that accuracy differences due to missing data substitution do not impact the material misstatement assessment.

Rationale for Proposed Updates Section 95131(b)(12)(B)

Based on questions that arose during implementation, the proposed change is necessary to clarify that accuracy differences due to missing data substitution do not impact the material misstatement assessment.

Summary of Proposed Updates Section 95131(b)(12)(C)

The proposed change allows a reporting entity to exclude inaccurate covered product data from the material misstatement assessment. Additionally, the verification statement may be calculated based upon a lower value of reported covered product data. Covered product data for the cement sector is summed for a single assessment of reasonable assurance of material misstatement and is excluded from this change.

Rationale for Proposed Updates Section 95131(b)(12)(C)

The proposed change, allowing exclusion of covered product data from the material misstatement assessment, is necessary to recognize that a portion of covered product data does demonstrate a reasonable assurance of no material misstatement. This change is not applicable to the cement sector because the covered product data include parameters in the Cap-and-Trade allocation of allowances equation that are in a numerator and a denominator.

Summary of Proposed Updates Section 95131(b)(13)

The proposed change deletes text in paragraph 95131(b)(13)(B) that was equivalent to the text in paragraph 95131(b)(13)(C) and moves the requirement in paragraph 95131(b)(13)(C) to paragraph 95131(b)(13)(B). In addition, the proposed language adds section 95158 of the reporting regulation, which was added to the mandatory reporting regulation in 2012.

Paragraph 95131(b)(13)(D) was re-lettered to paragraph (C). The proposed change clarifies that it is the required emissions calculation methodology that is the basis for a finding of non-conformance when data capture is less than the specified amount.

Paragraph 95131(b)(13)(E) was re-lettered to paragraph (D).

Rationale for Proposed Updates Section 95131(b)(13)

The proposed changes are necessary for clarification purposes, based on questions received from verifiers during implementation.

Summary of Proposed Updates Section 95131(b)(14)

The proposed change expands section 95131(b)(14) to include the requirements for assessment of covered product data reported by petroleum refinery operators for the transition from the first compliance period to the second compliance period. Multiple covered product data verification statements are required for 2013 and 2014 data. Additionally, the requirements for primary refinery products, the Solomon EII, carbon dioxide weighted tonne and complexity weighted barrel are outlined.

Rationale for Proposed Updates Section 95131(b)(14)

The updates specifying the requirements for assessment of covered product data reported by petroleum refinery operators are needed to ensure a smooth transition from the first to the second compliance period for the Cap-and-Trade regulation. Multiple covered product data verification statements are required for 2013 and 2014 emissions data reports to document the material misstatement assessment of primary refinery product data and conformance assessment of the Solomon Energy Intensity Index separate from the material misstatement assessments of the CO_2 weighted tonne and complexity weighted barrel.

Summary of Proposed Updates Section 95131(c)(1)

Updated language allows for two separate covered product data verification statements.

Rationale for Proposed Updates Section 95131(c)(1)

Two separate covered product data verification statements are required for 2013 and 2014 emissions data reports to document the material misstatement assessment of primary refinery product data and conformance assessment of the Solomon Energy Intensity Index separate from the material misstatement assessment of the CWT value and conformance assessment of throughput values.

Summary of Proposed Updates Section 95131(c)(3)

Updated language allows for multiple covered product data verification statements.

Rationale for Proposed Updates Section 95131(c)(3)

Two separate covered product data verification statements are required for 2013 and 2014 emissions data reports to document the material misstatement assessment of primary refinery product data and conformance assessment of the Solomon Energy Intensity Index separate from the material misstatement assessment of the CWT value and conformance assessment of throughput values.

Summary of Proposed Updates Section 95131(c)(4)

Proposed updates specify that a modified report and the adverse verification statement must be submitted to ARB by the deadline for purposes of the petition process.

Rationale for Proposed Updates Section 95131(c)(4)

Based on feedback from reporters and verifiers during previous reporting years, this was a needed clarification.

Summary of Proposed Updates Section 95131(e)

The update clarifies implementation of the verification statement set aside process, which may take place at the Executive Officer's discretion. The change clarifies a set aside may be considered when an error is identified after the verification deadline or when the emissions data report fails an ARB audit. In addition, changes that do not affect covered emissions, non-covered emissions, or covered product data may occur without a set aside of the verification statement.

Rationale for Proposed Updates Section 95131(e)

This change is necessary to clarify implementation of the verification statement set aside and report modification.

Summary of Proposed Updates Section 95131(i)(1)(B)(1)

Updated reference to the Cap-and-Trade regulation.

Rationale for Proposed Updates Section 95131(i)(1)(B)(1)

For consistency with the Cap-and-Trade regulation, the reference in this section was updated.

Section 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers and Verifiers of Emissions Data Reports and Offset Project Data Reports.

Summary of Proposed Updates Section 95132(b)(1)(A)(2)

Updated language clarifies that an employee used to meet minimum staff requirements for the purposes of verification body (VB) accreditation must be employed by the VB.

Rationale for Proposed Updates Section 95132(b)(1)(A)(2)

This change is necessary to clarify that the five staff used to meet the requirements for verification body accreditation must be employed. The previous language was ambiguous.

Summary of Proposed Updates Section 95132(b)(1)(C)

Added language specifies that the liability insurance requirement for accredited VBs is for professional liability insurance and not another type, such as general liability or an umbrella policy.

Rationale for Proposed Updates Section 95132(b)(1)(C)

This change is necessary to clarify that only professional liability insurance is sufficient for meeting the requirements for verification body accreditation

Summary of Proposed Updates Section 95132(b)(5)(B)

Reference to a specific section of the Cap-and-Trade section has been removed.

Rational for Proposed Updates Section 95132(b)(5)(B)

This section was updated to improve referencing consistency with the Cap-and-Trade regulation.

Summary of Proposed Updates Section 95132(d)

Added language to the title of this section to include the new requirement in section 95131(d)(4).

Rationale for Proposed Updates Section 95132(d)

This change is necessary to ensure consistency in the reporting regulation.

Summary of Proposed Updates Section 95132(d)(4)

New language in this section allows a verifier or VB to voluntarily withdraw from the mandatory reporting program without being suspended or revoked.

Rationale for Proposed Updates Section 95132(d)(4)

This change is necessary to allow a simpler process for a verifier or verification body to withdraw from the program.

Section 95133. Conflict of Interest Requirements for Verification Bodies.

Summary of Proposed Updates Section 95133(a)

New proposed language indicates that all subcontracting companies are also bound by the conflict of interest (COI) under this article.

Rationale for Proposed Updates Section 95133(a)

This change is necessary to clarify that COI requirements extend to other companies that contract with verification bodies on behalf of the reporting entities.

Summary of Proposed Updates Section 95133(b)(2)

Proposed updates specify that the assessment of services qualifying as a potential for high conflict, and that the high COI criteria also apply to any verifiers as well as subcontractors on the verification team.

Rationale for Proposed Updates Section 95133(b)(2)

This change is necessary to clarify which individuals are considered in the evaluation of high COI services.

Summary of Proposed Updates Section 95133(b)(2)(L)

Updated language specifies that high COI services related to development of environmental management systems (EMS), including an EMS conforming to the ISO 14001 or 50001 standard, constitutes the potential for a high risk of conflict of interest when the EMS scope includes activities that are also within the scope of GHG-emitting activities included in the emissions data report..

Rationale for Proposed Updates Section 95133(b)(2)(L)

This change is necessary to clarify which services related to management systems are considered high COI services, as opposed to those which are not high COI, as explained in section 95133(c)(3).

Summary of Proposed Updates Section 95133(b)(2)(T)

The proposed change clarifies that providing third-party verifications, other than ARB verification services, does not constitute a potential for a high conflict of interest, if conducted in accordance with the COI and impartiality requirements of this section, but those services must be included in the determination of the six-year limit.

Rationale for Proposed Updates Section 95133(b)(2)(T)

The proposed change, in conjunction with section 95133(c)(3), is needed to clarify that verifications that do not conform to requirements equivalent to those laid out in this section are considered high COI services.

Summary of Proposed Updates Section 95133(c)(2)

The proposed changes clarify that any third-party verifications provided to the reporting entity must be disclosed to ARB in the COI submittal. However, such third-party verifications are not subject to the 20 percent of fee threshold for determining medium COI, as long as those services are consistent with standards that are equivalent to those laid out in section 95133.

Rationale for Proposed Updates Section 95133(c)(2)

This change is necessary to clarify which services provided to a reporting entity are subject to the 20% threshold used to determine medium potential for COI, and clarifies that all services without exception must be disclosed to ARB.

Summary of Proposed Updates Section 95133(c)(3)

The proposed change clarifies that third-party verifications conducted outside of ARB's jurisdiction may still be considered low risk if they are conducted in accordance with, or equivalent to, section 95133, including, but not limited to, third-party certification of environmental management systems under the ISO 14001 standard or energy management systems under the ISO 50001 standard.

Rationale for Proposed Updates Section 95133(c)(3)

This change is needed to expand the scope of acceptable verification services beyond those provided under the auspices of California Climate Action Registry, The Climate Registry, and Climate Action Reserve. This change is consistent with our understanding that some verification bodies provide similar services to reporting entities as an independent auditor and that these services do not significantly increase the potential for COI, provided the verification team provides those services consistent with the principles laid out in section 95133 of the reporting regulation.

Summary of Proposed Updates Section 95133(g)(2)

Corrected a clerical error in the section.

Rationale for Proposed Updates Section 95133(g)(2)

Correction of errors further clarifies the original intent of the section.

Subarticle 5.

Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems

Section 95150. Definition of the Source Category.

Summary of Proposed Updates Section 95150(a)(2)

This section was updated to address the reporting of an onshore production facility that processes an emulsion.

Rationale for Proposed Updates Section 95150(a)(2)

This change was necessary to address the reporting of an emulsion by an onshore petroleum and natural gas production facility. This update supports product data reporting for the Cap-and-Trade program.

Section 95151. Reporting Threshold.

Summary of Proposed Updates Section 95151(a)

This section was edited for clarity and now refers reporters to the appropriate information found in the reporting threshold in section 95101.

Rationale for Proposed Updates Section 95151(a)

This change is necessary to provide clarity on the reporting thresholds for petroleum and natural gas systems.

Section 95152. Greenhouse Gases to Report.

Summary of Proposed Updates Section 95152(c)

This change was added to indicate that this industry segment also includes equipment to which an emulsion is transferred.

Rationale for Proposed Updates Section 95152(c)

This change is necessary to maintain consistency with the onshore petroleum and natural gas production industry segment description in section 95150(a)(2).

Summary of Proposed Updates Section 95152(c)(6)

Section 95152(c)(6) was updated to require reporting of well completion and workover emissions from all oil wells in addition to all gas wells.

Rationale for Proposed Updates Section 95152(c)(6)

This change is necessary to ensure the reporting of emissions from the oil wells completed and/or worked-over each year in California is completed. This will result in more complete emissions coverage because the majority of wells in California are oil wells.

Summary of Proposed Updates Section 95152(c)(15) and (16)

Emissions from crude oil and condensate, produced water, which are all described in section 95153(v), have been combined.

Rationale for Proposed Updates Section 95152(c)(15) and (16)

This change consolidates and clarifies the two reporting requirements which use the same methodology, a flash liberation test.

Summary of Proposed Updates Section 95152(c)(17), (18)

These sections were renumbered due to updates in the preceding sections.

Rationale for Proposed Updates Section 95152(c)(17), (18)

For completeness, these sections were renumbered when updates were made in prior sections.

Section 95153. Calculating GHG Emissions.

Summary of Proposed Updates Section 95153(c)(7)(A, B, C)

The three subsections of 95153(c)(7) were updated to edit clerical oversights.

Rationale for Proposed Updates Section 95153(c)(7)(A, B, C)

The sections were renumbered to keep consistency with the remainder of the mandatory reporting regulation.

Summary of Proposed Updates Section 95153(f)

Emissions reporting from all gas well completions and workovers were added to this reporting requirement. Previously, only emissions from gas well completions and workovers were to be reported.

Rationale for Proposed Updates Section 95153(f)

The inclusion of an emissions reporting requirement for gas wells completions and workovers will cover emissions from the oil wells drilled and completed or worked-over in California each year.

Summary of Proposed Updates Section 95153(f)(1)

The subscripts for the variable $V_{CO2/N2}$ in Equation 8 were edited for clarity. They should indicate $V_{CO2\ or\ N2}$, which is the proposed change.

Rationale for Proposed Updates Section 95153(f)(1)

The subscript updates are proposed for clarity purposes.

Summary of Proposed Updates Section 95153(h)

The title of this section was updated to correct a disconnect between the reporting requirements in section 95152(c)(8) and the reporting methods in this section.

Rationale for Proposed Updates Section 95153(h)

This change is necessary to define which emissions the reporting requirement found in section 95153(c)(8) requires.

Summary of Proposed Updates Section 95153(j)(3)

Staff has amended this section to correct the term "basin." Previously, this was listed as a "sub basin."

Rationale for Proposed Updates Section 95153(j)(3)

This change is necessary to correctly identify the "basin" term used in the equation.

Summary of Proposed Updates Section 95153(m)(1)(C)(2)

For consistency with the other sections in this article, section 95153(m)(1)(D) was renumbered to 95153(m)(1)(C)(2).

Rationale for Proposed Updates to Sections 95153(m)(1)(C)(2) and 95153(m)(3)

These proposed changes correct errors in a section number which was inconsistent with formatting in the section.

Summary of Proposed Updates Section 95153(m)(3)

Updates in this section corrected a typographical error.

Rationale for Proposed Updates Section 95153(m)(3)

This update corrects a typographical error.

Summary of Proposed Updates Section 95153(o)

For consistency with the other sections in this article, the industry section applicability was renumbered for onshore petroleum and natural gas production.

Rationale for Proposed Updates Section 95153(o)

This change is necessary for reporting consistency.

Summary of Proposed Updates Section 95153(p)

A typographic error has been corrected in this section where previously reporters were directed to use an incorrect methodology. Oil and gas production facilities will now be permitted to use either 95153(o) or (p) to estimate leaks.

Rationale for Proposed Updates Section 95153(p)

This is necessary to ensure that reporters have flexibility in reporting emissions from leaks and to align the reporting requirements with those from U.S.EPA.

Summary of Proposed Updates Section 95153(p)(6)

Two clerical issues are updated. In the definition of Equation 28 variables, the value $E_{s,i}$ should be derived from Equation 26 rather than 27, and the definition of the variable "Count" should refer to section (o)(8)(A) rather than (p)(8)(i).

Rationale for Proposed Updates Section 95153(p)(6)

Text which referred to an updated equation number and updated regulation section has been updated for consistency.

Summary of Proposed Updates Section 95153(u)

The description of variable V_v was added to Equation 33.

Rationale for Proposed Updates to Section 95153(u)

The added variable description corrects a prior omission from this equation.

Summary of Proposed Updates Section 95153(v)

A requirement to report the volume of produced water was added.

Rationale for Proposed Updates Section 95153(v)

The additional data reporting requirements were added to help ARB better assess this emission source.

Summary of Proposed Updates 95153(v)(1)(A)(1)

Language was added that references Appendix B of the regulation instead of other methods and also adds a reporting requirement for including the test results from the flash liberation test as part of the emissions data report.

Rationale for Proposed Updates 95153(v)(1)(A)(1)

These changes were necessary to ensure a California-specific method is used for the flash liberation test and the results are readily available for staff assessment, respectively.

Summary of Proposed Updates 95153(v)(1)(A)(2)(e)

Added language indicating the inclusion of the vapor recovery method in the test method.

Rationale for Proposed Updates 95153(v)(1)(A)(2)(e)

This change was necessary to direct the regulated entity to correct method to use for the evaluation of vapor recovery.

Summary of Proposed Updates Sections 95153(y)(1) and 95153(y)(1)(A)

Text was added to sections 95153(y)(1) and 95153(y)(1)(A) to ensure that the blending of fuels from Table C-1 of 40 CFR part 98 are reported using the correct data Tier.

Rationale for Proposed Updates Sections 95153(y)(1) and 95153(y)(1)(A)

This change is necessary to clarify an operator of onshore petroleum and natural gas systems reporting requirements with regards to blended fuel.

Summary of Proposed Updates Section 95153(y)(2)

Text was added to section 95153(y)(2) to correct a typographical error.

Rationale for Proposed Updates Section 95153(y)(2)

This change is necessary to correct a typographical error to ensure consistent reporting.

Summary of Proposed Updates Section 95153(y)(2)(A)

Text in section 95153(y)(2)(A) was edited to clarify that the common-pipe method is acceptable to use for this reporting requirement.

Rationale for Proposed Updates Section 95153(y)(2)(A)

This change is necessary to ensure a reporting entity can aggregate their reported emissions using the common pipe measurement to ensure the accuracy and completeness of their reported data.

Summary of Proposed Updates Section 95153(y)(2)(C)

Equations 35 and 36 were edited to indicate that monthly sampling is required. Text was added indicating that the volumetric natural gas emissions calculation using Equations 35 and 36 must be converted to GHG mass emissions. A provision to allow the use of measured HHV rather than the default value was also added.

Rationale for Proposed Updates Section 95153(y)(2)(C)

These changes are necessary to ensure the correct emissions values are reported. Without a reference to the sections that convert volumetric values to GHG emissions, reporters may report the wrong data.

Summary of Proposed Updates Section 95153(y)(2)(D)

A provision to allow the use of measured HHV rather than the default value was also added for the calculation of N_2O emissions. The term 'mmBtu' was changed to 'MMBtu.'

Rationale for Proposed Updates Section 95153(y)(2)(D)

This change is necessary to ensure an accurate representation of the high heat value measurements. Also, changes were made to the term 'MMBtu' to ensure consistent notation throughout the reporting regulation.

Summary of Proposed Updates Sections 95153(y)(3)-(4)

Typos were corrected in these sections for consistent denotations of MMBtu.

Rationale for Proposed Updates Sections 95153(y)(3)-(4)

This change is necessary to ensure consistency in reporting.

Section 95154. Monitoring and QA/QC Requirements.

Summary of Proposed Updates Section 95154(a)(1)

A typographical was corrected in three places in the section.

Rationale for Proposed Updates Section 95154(a)(1)

The word imaging was misspelled in three places.

Summary of Proposed Updates Section 95154(f)

The section on best available monitoring methods was removed from the proposed regulation.

Rationale for Proposed Updates Section 95154(f)

This change is necessary because the use of best available monitoring methods is no longer allowed as of January 1, 2013.

Section 95155. Procedures for Estimating Missing Data.

Summary of Proposed Updates Section 95155

Removed historical references to prior data years.

Rationale for Proposed Updates Section 95155

For consistency, reference to prior data reporting years has been removed.

Section 95156. Additional Data Reporting Requirements.

Summary of Proposed Updates Sections 95156(a)(7)-(10)

Similar clarifying text has been added indicating that oil and associated gas products associated with an emulsion needs to be reported in these sections.

Rationale for Proposed Updates Sections 95156(a)(7)-(10)

This change is necessary to ensure an operator that has an emulsion reports the product data associated with it in these sections.

Summary of Proposed Updates Section 95156(a)(11)

This section has been deleted.

Rationale for Proposed Updates Section 95156(a)(11)

This change is necessary because the provisions contained in this section are no longer applicable.

Summary of Proposed Updates Section 95156(b)

This change requires reporting of the annual volume of dry gas produced in MMBtu as opposed to Mscf. It also deletes regulatory text that is no longer applicable.

Rationale for Proposed Updates Section 95156(b)

These changes are necessary to ensure consistent reporting and to ensure that the reporting of dry gas is completed in the correct units to support the Cap-and-Trade program.

Summary of Proposed Updates Section 95156(c)

This section has been removed from the proposed regulation, and following sections are renumbered. Amended section 95156(c) has language that specifies onshore petroleum and natural gas production facilities with a gas plant that produces less than 25 MMscf per day must also report under this section.

Rationale for Proposed Updates Section 95156(c)

This change is necessary to ensure consistent reporting of product data in this section, which is used to support the Cap-and-Trade program.

Summary of Proposed Updates Section 95156(d)

The entire paragraph has been removed in the proposed regulation due to removal of references to historical data. The amended paragraph (d) requirement added for onshore natural gas processing facilities ensures that onshore natural gas processing facilities that have a throughput greater than 25 MMscf per day must report their volumes of associated gas, dry gas and natural gas processed.

Rationale for Proposed Updates Section 95156(d)

This change is necessary to remove obsolete historical references. The amended paragraph (d) requirements are designed to support the allocation of allowances under the Cap-and-Trade program.

Section 95157. Activity Data Reporting Requirements.

Summary of Proposed Updates Section 95157(c)(6)

Added requirement to report number of oil well completions and workovers as per section 95153(f).

Rationale for Proposed Updates Section 95157(c)(6)

This new reporting requirement is added to ensure that both oil and gas producers report activity data as required in the section 95153(f).

Summary of Proposed Updates Section 95157(c)(9)

The incorrect spelling of the word imaging has been corrected.

Rationale for Proposed Change to section 95157(c)(9)

Typos must be corrected to avoid confusion.

Summary of Proposed Updates Section 95157(c)(18)(B)

Methane was added to the reporting requirements for EOR emissions reporting.

Rationale for Proposed Updates Section 95157(c)(18)(B)

Both CO_2 and CH_4 are released during the blowdown of EOR equipment and the requirement to report CH_4 was inadvertently omitted during previous regulatory revisions.

Summary of Proposed Updates Section 95157(c)(19)(H)

Proposed language adds the requirement to report volumes (Mscf) of associated gas using both thermally enhanced and non-thermally enhanced production.

Rationale for Proposed Updates Section 95157(c)(19)(H)

This new language supports the GHG inventory reconciliation with the total statewide amounts of associated gas produced, as obtained by the Division of Oil, Gas and Geothermal Resources (DOGGR).

This data will also allow a direct comparison with DOGGR data on a field basis to better quality assure data has been reported correctly and consistently to both state agencies (CARB and DOGGR). Finally, this data will allow GHG inventory staff to obtain a statewide average heat content for associated gas (since it will have both the MMBtu and Mscf values) to replace its current default value for a more robust inventory dataset.

It is understood that this data (Mscf) is already measured by the reporters and would impose no new additional measurement requirements on them, it would simply require the reporting of this already measured data to CARB.

Appendix B

This appendix contains the ARB Test Procedure which is referenced in Section 95153(v) of the reporting regulation. This test procedure details an ARB methodology for the testing and determination of emissions via a flash liberation test.

Summary of Proposed Updates Appendix B

Appendix B has been added to the reporting regulation. The Appendix consists of a flash liberation test procedure developed by ARB. Section 95153(v) requires the use of a flash liberation test as a means of determining GHG emissions from produced water, crude oil, and condensate.

Rationale for Proposed Updates Appendix B

This change is necessary to conduct a flash liberation test on produced water and crude oil/condensate fractions. The test procedure in Appendix B was developed by ARB and is included in the reporting regulation for use by reporters.

VIII. PUBLIC PROCESS FOR DEVELOPMENT OF PROPOSED ACTION

Public Outreach

In developing the proposed amendments, staff presented initial ideas for discussion at a public workshop held on June 26, 2013. An informal discussion draft of proposed revisions to the regulation was released on July 17, 2013, to receive comments and feedback from stakeholders. In response to requests from stakeholders, staff held numerous one-on-one and small group teleconferences to discuss and refine the proposed revisions to the mandatory reporting regulation. Staff considered the informal comments provided during and after these meetings, in crafting the staff proposal (ARB Workshop Comments 2013).

IX. REFERENCES AND DOCUMENTS RELIED UPON

1. Definition of Volatile Organic Compounds (VOC). 40 CFR Part 51.100(s). United States Environmental Protection Agency. March 31, 2009. http://www.epa.gov/ttn/naaqs/ozone/ozonetech/def_voc.htm (accessed August 2, 2013)
2. Definition of Toxic Air Contaminant. California Health and Safety Code, Section 39655(a). http://www.leginfo.ca.gov/cgi-bin/displaycode?section=hsc&group=39001-40000&file=39655 (accessed August 2, 2013)
3. ASTM D-70 – 09 "*Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method),*" 2010.
4. ASTM D-287 – 92 "*Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method),*" 2006.
5. ASTM D-1945 – 03 "*Standard Test Method for Analysis of Natural Gas by Gas Chromatography,*" 2003.
6. ASTM D-2597 – 94 "*Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*", 2004.
7. ASTM D-3710 – 95 "*Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography,*" 1999.
8. ASTM D-3588 – 98 "*Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels,*" 2003.
9. ASTM D-4007 – 08 "*Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method,*" *(Laboratory Procedure)* 2008.
10. ASTM D-4052 – 09 "*Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter,*" 2009.

11. ASTM D-5002 – 99 *"Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer,"* 2010.

12. ASTM D-5504 – 08 *"Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence,"* 2008.

13. ASTM D-6228 – 10 *"Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection,"* 2010.

14. California Health and Safety Code, Part 3 of Division 26, commencing with Section 40000. *Air Pollution Control Districts.* http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=hsc (accessed August 22, 2013)

15. *"Columbia Treaty: Treaty between Canada and the United States of America relating to Cooperative Development of the Water Resources of The Columbia River Basin,"* January 17, 1961.

16. EPA Method 15 *"Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources,"* 1996.

17. EPA Method 16 *"Semicontinuous Determination of Sulfur Emissions from Stationary Sources,"* 1996.

18. EPA Method 8021B *"Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors,"* 1996.

19. EPA Method 8260B *"Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS),"* 1996.

20. EPA Method TO-14 *"Determination of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters with Subsequent Analysis by Gas Chromatography,"* 1999.

21. EPA Method TO-15 *"Determination of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters and Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS),"* 1999.

22. GPA 2174 – 93 *"Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography,"* 1993.

23. GPA 2177 – 03 *"Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography,"* 2003

24. GPA 2261 – 00 *"Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,"* 2000.

25. GPA 2286 – 95 *"Tentative Method of Extended Analysis for Natural Gas and*

Similar Gaseous Mixtures by Temperature Programmed Gas Chromatography," 1995.

26. ISO 12625-8:2010 "*Tissue paper and tissue products – Part 8: Water-absorption time and water-absorption capacity, basket-immersion test method*," International Standards Organization, 2010
27. ISO 50001 "*Energy Management Systems – Requirements with Guidance for Use*," International Standards Organization, 2011
28. *"Official Methods of Analysis of the Association of Official Analytical Chemists*," 13th Ed., 1980, sections 32.025 to 32.030, under the heading "Method III (Potentiometric Method)."
29. "*Official Methods of Analysis of the Association of Official Analytical Chemists*," 13th Ed., 1980, sections 32.014 to 32.016 and 52.012.
30. *"Standards for Gas Service in the State of California, General Order No. 58A."* State of California, Public Utilities Commission. 1992.

APPENDIX A TO THE STAFF REPORT

PROPOSED REGULATION ORDER

Note: The pre-existing regulation text is set forth below in normal type. The proposed amendments are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions. Portions of the regulation that are nonsubstantively changed with renumbering are indicated by [Nonsubstantive changes to indicate renumbering]. The symbol "******" means that intervening text not proposed for amendment is not shown.]

PROPOSED AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95101, 95102, 95103, 95104, 95105, 95110, 95111, 95112, 95113, 95114, 95115, 95116, 95117, 95118,95119, 95120, 95121, 95122, 95123, 95129, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, title 17 California Code of Regulations; Proposed adoption of new section 95124, new Appendix B, title 17, California Code of Regulations to read as follows:

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

***

§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

***

(B) Operators of facilities located in California with source categories listed below, are subject to this article when stationary combustion and process emissions of CO_2, CH_4, and N_2O equal or exceed 10,000 metric tons CO_2e for a calendar year:

***

8. Lead production;

***

(G) Any California reporting entity subject to subparts E, F, G, I, K, L, O, R, T, U, X, Z, BB, CC, EE, FF, GG, II, LL, OO, QQ, SS, or TT of 40 CFR Part 98 that emits over 10,000 metric tons of CO_2e resulting from CO_2, N_2O, or CH_4 emissions. If a reporting entity utilizes the above industrial processes and emits over 10,000 metric tons of CO_2e resulting from CO_2, N_2O, or

CH_4 emissions, they must notify the Executive Officer within 90 days of the effective date of this regulation or within 90 days of commencing the industrial process. This notification requirement also applies to facility operators subject to section 95103(a), for abbreviated reporting.

(2) Any reporting entity ~~that fits~~ into one or more of the categories in subsection (a)(1) above ~~for calendar year 2011 or later~~ must submit an annual emissions data report ~~for that year and for subsequent calendar years~~, except as provided in the ~~report~~ cessation provisions of subsections (h) and (i) of this section. The emissions data report must cover all source categories and GHGs for which calculation methods are provided or referenced in this article for the reporting entity. Except as otherwise specified in this article, the report must be compiled using the methods specified by source category in 40 CFR Part 98.

(3) If a facility operator determines their reporting applicability and responsibility on the basis of common ownership, the basis of reporting applicability and responsibility can only be changed to common control at the beginning of a compliance period. If a facility operator determines their reporting applicability and responsibility on the basis of common control, the basis of reporting applicability and responsibility can only be changed to common ownership at the beginning of a compliance period. These provisions do not apply if there is a legal change in facility ownership. If there is a change in facility ownership, the provisions of section 95103(n) apply.

~~(3)~~(4) *Verifiers and Verification Bodies*. In addition to the reporting entities specified in subsection (a)(1) above, this article contains requirements for entities acting as verification bodies and individuals acting as third party verifiers of emissions data reports and offset project data reports. These requirements are specified in sections 95130 through 95133 of this article.

(b) *Calculating GHG Emissions Relative to Thresholds*. For ~~industrial~~ facilities for which an emissions-based applicability threshold is specified in section 95101(a)(1), the operator must calculate emissions for comparison to applicable thresholds ~~using the requirements of 40 CFR §98.2(b)-(c), except~~ as specified below:

(1) For the purpose of computing emissions relative to the 25,000 metric ton CO_2e threshold specified in section 95812 of the cap-and-trade regulation, operators must include all covered emissions of CO_2, CH_4, and N_2O.

(2) For the purpose of computing emissions relative to the 10,000 metric ton CO_2e threshold for reporting applicability specified in section 95101(a), operators must include emissions of CO_2, CH_4 and N_2O from stationary combustion sources and process emissions, but may exclude any vented and fugitive emissions from the estimate. However, if all the CO_2, CH_4, and N_2O emissions captured within the reporting entity's facility boundary, including vented and

fugitive emissions, exceed the 25,000 metric ton CO_2e threshold specified in sections 95103(a) and 95103(f), the reporting entity is not eligible for the abbreviated reporting option provided in section 95103(a) and must submit an emissions data report pursuant to the full requirements of this Article, including obtaining verification services pursuant to section 95103(f).

***

(6) Operators of a hydrogen fuel cell unit must include emissions from the hydrogen fuel cell unit in calculating emissions for comparison to applicability thresholds.

(c) *Fuel and Carbon Dioxide Suppliers.* The suppliers listed below, as defined in section 95102(a), are required to report under this article when they produce, import and/or deliver an annual quantity of fuel that, if completely combusted, oxidized, or used in other processes, would result in the release of greater than or equal to 10,000 metric tons of CO_2e in California, unless otherwise specified in this article:

(1) Position holders at terminals and refineries delivering petroleum fuels and/or biomass-derived fuels, as described in section 95121;

***

(5) California consignees of imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas, as described in section 95122;

***

(10) Operators of liquefied natural gas production facilities that produce liquefied natural gas products from natural gas received from interstate pipelines, as described in section 95122;

***

(f) *Exclusions.* This article does not apply to, and greenhouse gas emissions reporting is not required for:

***

~~(8) The emissions source categories specified in 40 CFR Part 98, Subparts E, F, G, I, K, L, O, R, T, X, Z, BB, CC, DD, EE, FF, GG, II, LL, OO, QQ, SS and TT. However, a reporting entity who after the effective date of this article commences an industrial process identified in one of these subparts must notify the Executive Officer within 90 days of beginning that new process;~~

(~~9~~8) Agricultural irrigation pumps.

***

(h) *Cessation of Reporting.* A facility operator or supplier who is not subject to the cap-and-trade regulation, whose emissions fall below the applicable emissions reporting thresholds of this article and who wishes to cease annual reporting must comply

with the requirements specified in ~~this paragraph~~section 95101(h). A reporting entity that is subject to the cap-and-trade regulation must follow the requirements in section 95812 and continue to comply with all reporting requirements until there is no longer a compliance obligation. If the compliance obligation ceases, the reporting entity must still follow the requirements in section 95101(h) before ceasing to comply with the reporting requirements of this article. The operator or supplier must provide the letter notifications specified below to the address indicated in section 95103 of this article.

***

~~(3) The verification requirements of this article do not apply to the first full year of non-operation following a permanent shutdown, but continue to apply to prior emissions data reports~~.

(43) Electric power entities must comply with the following requirements for cessation of reporting:

(A) Electric power entities that import or export electricity in 2011 or 2012 must continue to submit~~,~~ and certify~~, and verify~~ an emissions data report through the 2014 data year~~, the end of the first compliance period~~. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(B) Electric power entities that import or export electricity in any year of a subsequent compliance period must continue to submit~~,~~ and certify~~, and verify~~ an emissions data report through the end of the same compliance period. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(C) Electric power entities no longer importing or exporting electricity at the beginning of a subsequent compliance period are not required to submit, and certify~~, and verify~~ an emissions data report demonstrating that they have no imports or exports pursuant to this article, but must notify the Executive Officer in writing of the reason(s) for cessation of reporting. The notification must be submitted no later than March 31 of the year following the last year that the electric power entity is required to submit an emissions data report.

***

(i) *Cessation of Verification*. A facility operator, supplier, or electric power entity who wishes to cease annual verification must comply with the requirements specified in section 95101(i) and notify ARB by the applicable reporting deadline if the reporting entity has met the cessation criteria and intends to no longer obtain verification services. A reporting entity that is subject to the cap-and-trade regulation must follow the requirements in section 95812 and continue to comply with all verification requirements until there is no longer a compliance obligation. If the compliance obligation ceases, the

reporting entity must still follow the requirements in section 95101(i) before ceasing to comply with the verification requirements of this Article.

(1) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraph 95101(a)(1) of this section cease to operate or are permanently shut down, the owner, operator, or supplier must continue to obtain the services of an accredited verification body for purposes of verifying the emissions data report for the year in which the facility or supplier's GHG-emitting processes and operations ceased to operate. Verification is not required for the emissions data report of the first full year of non-operation that follows.

(2) If the operations of an electric power entity are changed such that the entity ceases to import and export electricity, the electric power entity must continue to obtain the services of an accredited verification body for purposes of verifying the emissions data report for the year in which the imports and exports ceased. Verification is not required for the emissions data report of the first full year of non-operation that follows.

(3) A facility operator or supplier whose emissions decrease to less than 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, must continue to obtain the services of an accredited verification body for purposes of verifying the emissions data report for the first year in which the facility or supplier's emissions are less than 25,000 metric tons of CO_2e.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95102. Definitions.

(a) For the purposes of this article, the ~~following~~ definitions in subsections (a) and (b) shall apply. Subsection (b) is specific to product data definitions.

***

(6) "Adverse emissions data verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the emissions data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirement to fix such errors pursuant to section 95131(b)(9), or both ~~and is in conformance with section 95131(b)(9) for the emissions data~~.

(7) "Adverse product data verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the covered product data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirements to fix such errors pursuant to section 95131(b)(9), or both ~~and is in conformance with section 95131(b)(9) for the product data~~.

(8) "Adverse verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that the emissions or covered product data submitted in the emissions data report contains correctable errors as defined pursuant to this section and thus is not in conformance with the requirements to fix such errors pursuant to section 95131(b)(9), or both ~~and is in conformance with section 95131(b)(9)~~. This definition applies to the adverse emissions data verification statement and the adverse product data verification statement.

***

~~(10) "Air dried ton of paper" means paper with 6 percent moisture content.~~

***[No changes except to renumber]

(13) "API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, water, or natural gas. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F, and where API refers to the American Petroleum Institute.

(14) "AQMD/APCD" or "air district" ~~means~~ or "air quality management district" or "air pollution control district" means any district created or continued in

existence pursuant to the provisions of Part 3 (commencing with Section 40000) of Division 26 of the Health and Safety Code.

***[No changes except to renumber]

(16) "ARB ID" means, for the purposes of this article, the unique identification number assigned to each facility, supplier, and electric power entity that reports GHG emissions to the ARB.

***[No changes except to renumber]

(~~19~~20) "Asset-controlling supplier" means any entity that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for these facilities even though it does not own them, and is assigned a supplier-specific identification number and system emission factor by ARB for the wholesale electricity procured from its system and imported into California. Asset controlling suppliers are considered specified sources.

***[No changes except to renumber]

(~~28~~29) "Barrel of oil equivalent," with respect to reporting of oil and gas production, means barrels of crude oil produced, plus associated gas and dry gas produced converted to barrels at 5.8 MMBtu per barrel.

***[No changes except to renumber]

(48) "BTEX" means gaseous compounds of benzene, toluene, ethyl benzene, and xylenes.

***[No changes except to renumber]

(55) "By-product hydrogen" means hydrogen produced as a result of a process or processes dedicated to producing other products (e.g. catalytic reforming).

***[No changes except to renumber]

~~(56) "Calcium ammonium nitrate solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.~~

***[No changes except to renumber]

~~(81) "Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.~~

***[No changes except to renumber]

~~(83) "Coal bed methane" or "CBM" means natural gas which is extracted from underground coal deposits or "beds."~~

***[No changes except to renumber]

~~(88) "Cold rolled and annealed steel sheet" means steel that is cold rolled and then annealed. Cold rolling means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature. Annealing is a heat or thermal treatment process by which a previously cold-rolled steel coil is made more suitable for forming and bending. The steel sheet is heated to a designated temperature for a sufficient amount of time and then cooled.~~

~~(89) "Cold rolling of steel" means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature.~~

***[No changes except to renumber]

(90) "Common control" means having common "operational control" as defined herein.

***[No changes except to renumber]

~~(103) "Container Glass pulled" means the quantity of glass removed from the melting furnace in the container glass manufacturing process where "container glass" is defined as glass products used for packaging.~~

***[No changes except to renumber]

(105) "Conventional wells" mean crude oil or gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

***[No changes except to renumber]

~~(109) "Conventional wells" mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.~~

(107) "Correctable errors" means errors identified by the verification team that affect covered emissions data, non-covered emissions data, or covered product data in the submitted emissions data report that result from a non-conformance with this article. Differences that, in the professional judgment of the verification team, are the result of differing but reasonable

methods of truncation or rounding or averaging, where a specific procedure is not prescribed by this article, are not considered errors and therefore do not require correction.

***[No changes except to renumber]

(111) "Criteria pollutant" is defined as emissions of oxides of nitrogen (NOx), oxides of sulfur (SOx), particulate matter 10 and 2.5 microns or less in diameter (PM_{10} and $PM_{2.5}$), carbon monoxide (CO), and volatile organic compounds (VOC (e.g., reactive organic gases)) as defined in 40 CFR 51.100 (s)(1).

***[No changes except to renumber]

~~(131) "Dolime" is calcined dolomite.~~

(130) "District Heating Facility" means a facility that, at a central plant, produces hot water, steam and/or chilled water that is distributed through underground pipes to buildings and facilities connected to the system that are not part of the same facility. District Heating Facility does not include a facility that produces electricity.

(131) "Double-Valve Cylinder," for purposes of Appendix B, means a cylinder used for gathering crude oil or condensate samples. The cylinder is provided by a laboratory filled with laboratory grade water which prevents flashing within the cylinder.

***[No changes except to renumber]

(135) "EIM Participating Resource Scheduling Coordinator" means the participating resource owner or operator, or a third-party designated by the resource owner or operator, that is certified by the CAISO and enters into the pro forma EIM Participating Resource Scheduling Coordinator Agreement, under which it is responsible for meeting the requirements specified in the CAISO tariff on behalf of the resource owner or operator.

***[No changes except to renumber]

(~~137~~138) "Electricity exporter" means electric power entities that deliver exported electricity. The entity that exports electricity is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path, with the point of receipt located inside the state of California and the point of delivery located outside the state of California. Electricity exporters include Energy Imbalance Market (EIM) Entity Scheduling Coordinators serving the EIM market that can result in exports from California.

***[No changes except to renumber]

(~~140~~141) "Electricity importers" deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the state of California, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the 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. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR). Electricity Importers include EIM Participating Resource Scheduling Coordinators serving the EIM market whose transactions result in electricity imports into California.

***[No changes except to renumber]

(~~146~~147) "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by this article. The emissions data report is for the submission of required data for the calendar year prior to the year in which the report is due. For example, a 2013 emissions data report would cover emissions and product data for the 2013 calendar year and would be reported in 2014.

***[No changes except to renumber]

(149) "Emulsion" means a mixture of water, crude oil, associated gas, and other components from the oil extraction process that is transferred from an existing platform that is permanently affixed to the ocean floor and that is located outside the distance specified in the "offshore" definition of this article, to an onshore petroleum and natural gas production facility. For purposes Appendix B, emulsion means a mixture of crude oil, condensate, or produced water in any proportion.

***[No changes except to renumber]

(151) "Energy Imbalance Market" or "EIM" means the operation of the CAISO's real-time market to manage transmission congestion and optimize procurement of energy to balance supply and demand for the combined CAISO and EIM footprint.

(152) "Energy Imbalance Market, Participating Resource Scheduling

Coordinator" or "EIM" Participating Resource Scheduling Coordinator means the participating resource owner or operator , or a third-party designated by the resource owner or operator that is certified by the CAISO and enters into the pro forma EIM Participating Resource Scheduling Coordinator Agreement, under which it is responsible for meeting the requirements specified in the CAISO Tariff on behalf of the resource owner or operator.

***[No changes except to renumber]

(~~167~~171) "Facility," with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, means all petroleum and natural gas equipment on a well-pad, ~~or~~ associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single ~~hydrocarbon~~ basin as defined in section 95102(a). When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

***[No changes except to renumber]

~~(170) "Fiberglass glass pulled" means the quantity of glass removed from the melting furnace in the fiberglass manufacturing process where "fiberglass" is defined as insulation products for thermal, acoustic and fire applications manufactured using glass.~~

***[No changes except to renumber]

(~~176~~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. 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.

***[No changes except to renumber]

(185) "Flashing," for purposes of Appendix B, means the release of hydrocarbons and carbon dioxide from liquid to surrounding air when the liquid changes temperature and pressure, also known as phase change.

(186) "Flash Analysis," for purposes of Appendix B, means laboratory methodologies for measuring the volume and composition of gases released from liquids, including the molecular weight of the total gaseous sample, the weight percent of individual compounds, and a Gas-Oil Ratio or Gas-Water Ratio required to calculate the specified emission rates as described in Section 10 of Appendix B.

~~(182) "Flat glass pulled" means the quantity of glass removed from the melting furnace in the flat glass manufacturing process where "flat glass" is defined as glass initially manufactured in a sheet form.~~

(187) "Floating-Piston Cylinder," for purposes of Appendix B, means a cylinder used for gathering produced water. The cylinder contains an internal piston controlled by gas pressure. The piston prevents sample liquid from flashing within the sampling cylinder and provides a means of extracting the sample liquid.

***[No changes except to renumber]

(189) "Flowback Fluid," for purposes of Appendix B, means chemicals, fluids, or proppants injected underground under pressure to stimulate or hydraulically fracture a crude oil or natural gas well or reservoir and that flows back to the surface as a fluid after injection is completed.

***[No changes except to renumber]

(~~200~~206) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas including operators of interstate and intrastate pipelines, a supplier of liquefied natural gas, or a supplier of liquid petroleum gas as specified in this article.

***[No changes except to renumber]

~~(207) "Galvanized steel sheet" means steel coated with a thin layer of zinc to provide corrosion resistance for such products as garbage cans, storage tanks, or framing for buildings. Sheet steel normally must be cold-rolled prior to the galvanizing stage.~~

***[No changes except to renumber]

(217) "Gas to water ratio (GWR)," for purposes of Appendix B, means the ratio of gas produced from a barrel of produced water when cooling and

depressurizing produced water to standard conditions, expressed in terms of standard cubic feet of gas per barrel of water.

***[No changes except to renumber]

(225) "Graduated Cylinder," for purposes of Appendix B, means a measuring instrument for measuring fluid volume, such as a glass container (cup or cylinder or flask) which has sides marked with or divided into amounts.

***[No changes except to renumber]

~~(235) "Hot rolled steel sheet" means steel produced from the rolling mill that reduces a hot slab into a coil of specified thickness at a relatively high temperature.~~

***[No changes except to renumber]

(~~240~~245) "Imported electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into the state of California from a facility or unit physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, defined pursuant to this section. Imported electricity does not include electricity imported into the California Independent System Operator (CAISO) balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the state of California. 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 Electric Reliability Corporation or Western Electricity Coordinating Council. Imported electricity shall include Energy Imbalance Market dispatches designated by the CAISO's optimization model and reported by the CAISO to EIM Participating Resource Scheduling Coordinators as electricity imported to serve retail customers load that are located within the State of California.

***[No changes except to renumber]

(~~242~~247) "Independently operated and sited cogeneration/bigeneration facility" means a cogeneration or bigeneration facility that is not located on the same facility footprint as its thermal host and has different operational control and different ownership than the thermal host.

(~~243~~248) "Independently operated cogeneration/bigeneration facility co-located with the thermal host" means a cogeneration or bigeneration facility that is located on the same ~~facility~~property footprint as its thermal host but has different operational control and different ownership than the thermal host.

***[No changes except to renumber]

(~~249~~254) "Intrastate pipeline" means any pipeline or piping system wholly within the state of California that is delivering natural gas to end-users and is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission. For purposes of this article, intrastate pipeline operators that physically deliver gas to end users in California are considered to be Local Distribution Companies. Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines

***[No changes except to renumber]

(~~271~~276) "Local distribution company" or "LDC," for purposes of this article, means a company that owns or operates distribution pipelines, not interstate pipelines, that physically deliver natural gas to end users and includes public utility gas corporations, publicly-owned natural gas utilities and intrastate pipelines that are delivering natural gas to end users.

***[No changes except to renumber]

~~(286) "Mixed crude oil" means a mix of both heavy and light crude oil.~~

(~~287~~291) "MMBtu" means million British thermal units.

***[No changes except to renumber]

(~~289~~293) "Motor vehicle fuel" means gasoline. It does not include aviation gasoline, jet fuel, diesel fuel, kerosene, liquefied petroleum gas, natural gas in liquid or gaseous form, ~~alcohol,~~ or racing fuel.

***[No changes except to renumber]

(305) "Natural gas supplier" means, for the purposes of this article, the local distribution company or interstate pipeline that owns or operates the distribution pipelines that physically deliver natural gas to end users.

***[No changes except to renumber]

~~(304) "Nitric acid" means HNO_3 of 100% purity.~~

***[No changes except to renumber]

(325) "On-purpose hydrogen" means hydrogen produced as a result of a process or processes dedicated to producing hydrogen (e.g., steam methane reforming).

(~~321~~326) "Onshore petroleum and natural gas production facility" means all petroleum or natural gas equipment on a well pad, or associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator that are located in a single ~~hydrocarbon~~ basin as defined in 40 CFR §98.238. When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or operating entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

***[No changes except to renumber]

(332) "Operating Pressure," for purposes of Appendix B means the working pressure that characterizes the conditions of crude oil, condensate, or produced water inside a particular process, pipeline, vessel or tank. In general, low pressure liquid is under less than approximately 200 psig of pressure.

***[No changes except to renumber]

(334) "Parasitic load" means the amount of electricity consumed by auxiliary equipment that supports the electricity generation or cogeneration process. The equipment may include fans, pumps, drive motors, pollution control equipment, lighting, computer, CEMS, and other equipment.

***[No changes except to renumber]

(339) "Percent Water Cut," for purposes of Appendix B, means the percentage of water by volume, of the total emulsion throughput as measured using ASTM D-4007. The percent water cut is expressed as a percentage.

***[No changes except to renumber]

~~(337) "Pickled steel sheet" means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides.~~

***[No changes except to renumber]

~~(339) "Plaster" is calcined gypsum that is produced and sold as a finished product and is not used in the production of plasterboard at the same facility.~~

~~(340) "Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.~~

***[No changes except to renumber]

(~~351~~356) "Power contract" or "written power contract," as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means a written document, including associated verbal or electronic records if included as part of the written power contract, arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, applicable international treaties, and tariff provisions, without regard to duration, or written agreements to import or export on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity. A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, system, or asset-controlling supplier's system that is designated at the time the transaction is executed.

***[No changes except to renumber]

(~~354~~359) "Primary refinery products" means aviation gasoline, motor gasoline (finished), motor gasoline blendstocks, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. For the purpose of calculating this value for each refinery ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

(360) "Primary Vessel," for purposes of Appendix B means a separator or tank that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more crude oil, condensate, or natural gas wells or field gathering systems.

***[No changes except to renumber]

(~~358~~364) "Process emissions specialist" means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators of facilities engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, ~~and~~ nitric acid production, and lead production.

***[No changes except to renumber]

(369) "Produced water" means the resulting water that is produced as a byproduct of crude oil or natural gas production.

***[No changes except to renumber]

(390) "Qualified Thermal Output" means the thermal energy generated by a cogeneration unit or district heating facility that is sold to particular end-users and reported pursuant to MRR section 95112(a)(5)(A) and the thermal energy used on-site by industrial processes or operations and heating and cooling operations that is not in support of or a part of the electricity generation or cogeneration system and is reported pursuant to MRR sections 95112(a)(5)(C). Qualified thermal output does not include thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations, or, for a facility with a cogeneration unit, any thermal energy generated by equipment that is not an integral part of the cogeneration unit.

***[No changes except to renumber]

~~(392) "Recycled" refers to a material that is reused or reclaimed.~~

~~(393) "Recycled boxboard" means containers of solid fiber made from recycled fibers, including cereal boxes, shoe boxes and protective paper packaging for dry foods. It also includes folding paper cartons, set-up boxes, and similar boxboard products. Recycled boxboard is made from recycled fibers.~~

~~(394) "Recycled linerboard" means types of paperboard made from recycled fibers that meet specific tests adopted by the packaging industry to qualify for use as the outer facing layer for corrugated board, from which shipping containers are made.~~

~~(395) "Recycled medium" means the center segment of corrugated shipping containers, being faced with linerboard on both sides. Recycled medium is made from recycled fibers.~~

***[No changes except to renumber]

(~~406~~410) "Renewable Energy Credit" or "REC" has the same meaning ~~as ascribed to the cap-and-trade regulation section 95802(a).~~) defined in the California Energy Commission's "Renewable Portfolio Standard Eligibility, 7th edition, Commission Guidebook, April, 2013; CEC-300-2013-005-ED7-CMF.

***[No changes except to renumber]

(~~411~~415) "Reservoir" means a porous and permeable underground natural formation containing ~~significant quantities of hydrocarbon liquids and/or gases~~crude oil or gases. A reservoir is characterized by a single natural pressure.

***[No changes except to renumber]

(422) "Secondary Vessel," for purposes of Appendix B means a separator or tank that receives crude oil, condensate, produced water, natural gas, or emulsion from one or more primary vessel separators or tanks.

***[No changes except to renumber]

(~~420~~425) "Separator" means a sump or vessel ~~in~~used to~~in which streams of multiple phases are gravity~~ separated ~~into~~crude oil, condensate, natural gas, produced water, emulsion or solids~~into individual streams of single phase~~.

***[No changes except to renumber]

~~(425) "Soda ash equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.~~

***[No changes except to renumber]

(432) "Sorbent" means a material used to absorb or adsorb liquids or gases.

***[No changes except to renumber]

(~~431~~436) "Source of generation" or "generation source" means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, ~~also referred to as the first point of receipt~~.

***[No changes except to renumber]

(438) "SSM" means periods of startup, shutdown and malfunction.

***[No changes except to renumber]

~~(437) "SSM" means periods of startup, shutdown and malfunction.~~

(~~438~~443) "Stationary" means neither portable nor self-propelled, and operated at a single facility.

***[No changes except to renumber]

~~(441) "Stucco" means hemihydrate plaster ($CaSO_4 \bullet \frac{1}{2}H_2O$) produced by heating ("calcining") raw gypsum, thereby removing three-quarters of its chemically combined water.~~

***[No changes except to renumber]

(447) "Sump," for purposes of Appendix B means a lined or unlined surface impoundment or depression in the ground that, during normal operations, is used for separating crude oil, condensate, produced water, emulsion, or solids.

***[No changes except to renumber]

(~~445~~449) "Supplier" means a producer, importer, exporter, position holder, interstate pipeline operator, or local distribution company of a fossil fuel or an industrial greenhouse gas.

***[No changes except to renumber]

(451) "System power" means wholesale electricity procured from a system power supplier and NERC e-tagged as a representative weighted average power output from all generation resources under the ownership or control of the system power supplier which contribute to the power output mix. For purposes of this article, this definition applies to cases where the carbon intensity of the system power supplier's weighted average power output is greater than the default emission factor set forth in 95111(b)(1).

(452) "System power supplier" means an electric utility power system or balancing authority area with inter-connected electricity generating facilities which is assigned a supplier-specific identification number and system emission factor by ARB for the wholesale electricity procured as system power from its system and imported into California.

***[No changes except to renumber]

(454) "Tank," for the purposes of Appendix B, means a container, constructed primarily of non-earthen materials, used for holding or storing crude oil, condensate, produced water, or emulsion.

(455) "Tentatively Identified Compound List," for purposes of Appendix B means a list of target compounds that laboratories can use to evaluate uncommon gaseous compounds when performing a Gas Chromatograph/ Mass Spectrometry analysis.

***[No changes except to renumber]

(460) "Three-Phase Separator," for purposes of Appendix B, means a pressurized vessel sealed from the atmosphere used to gravimetrically separate crude oil, produced water and gases.

(461) "Two-Phase Separator," for purposes of Appendix B, means a pressurized vessel sealed from the atmosphere used to gravimetrically separate crude oil and produced water that still contain entrained gases.

(462) "Throughput" for the purposes of Appendix B, means the average volume of liquid processed by a vessel over a period of time, such as barrels per day. The throughput of crude oil or condensate may need to be calculated using the Percent Water Cut. The throughput of crude oil or condensate is calculated as the difference between those liquids and the produced water.

***[No changes except to renumber]

~~(457) "Tin Plate" means thin sheet steel with a very thin coating of metallic tin. Tin plate also includes Tin Free Steel or TFS which has an extremely thin coating of chromium, metallic and oxide. Tin plate is used primarily in canmaking.~~

~~(458) "Tissue" means a class of papers which are characteristically gauzy in texture and, in some cases, fairly transparent. They may be glazed, unglazed, or creped, and are used for a variety of purposes. Examples of different types of tissue papers include sanitary grades such as toilet, facial, napkin, towels, wipes, and special sanitary papers.~~

***[No changes except to renumber]

(471) "Toxic air contaminant" is as defined in Health and Safety Code section §39655(a).

***[No changes except to renumber]

(~~463~~473) "Transmission-distribution (T-D) transfer station" means a ~~Federal Energy Regulatory Commission rate-regulated Interstate pipeline, or a~~

~~pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717 717 (w)(1994).)~~metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

***[No changes except to renumber]

(476) "Treaty power" means electricity returned to Canada from the United States under the Columbia River Treaty, an international treaty. The source of treaty power is neither specified nor unspecified. Treaty power shall be accorded an emission factor of zero.

***[No changes except to renumber]

(~~470~~481) "Unconventional wells" means crude oil or gas wells in producing fields that employ hydraulic fracturing to enhance crude oil or gas production volumes.

***[No changes except to renumber]

(~~476~~487) "Used oil" means a petroleum-derived or synthetically-derived oil whose physical properties have changed as a result of handling or use, such that the oil cannot be used for its original purpose. Used oil consists primarily of automotive oils (-e.g., used motor oil, transmission oil, hydraulic fluids, brake fluid, etc.~~)~~.) and industrial oils (-e.g., industrial engine oils, metalworking oils, process oils, industrial grease, etc.).

***[No changes except to renumber]

(500) "Vessel," for the purposes of Appendix B, means any container, constructed primarily of non-earthen materials, used to separate or store crude oil, condensate, natural gas, produced water, or emulsion.

(502) "VOC_{C3-C9}," for purposes of Appendix B, means Volatile Organic Compounds with three to nine carbon atoms.

(503) "VOC_{C10+}," for purposes of Appendix B, means Volatile Organic Compounds with 10 or more carbon atoms. This value is needed for laboratory and quality control purposes.

***[No changes except to renumber]

(b) For the purposes of this article, the following definitions associated with reported product data shall apply:

(1) "Activin" means the extract from grape seeds containing concentrations of proanthocyanidin ($C_{31}H_{28}O_{12}$).

(2) "Air dried ton of paper" means paper with 6 percent moisture content.

(3) "Almond" means the edible seeds of the almond (*Prunus amygdalus*).

(4) Aluminum and aluminum alloy billet" means a solid bar of nonferrous metal, produced by casting molten aluminum alloys, and suitable for subsequent rolling, casting, or extrusion.

(5) "Aluminum alloy" is an alloy in which aluminum is the predominant metal and the alloying elements may typically be copper, magnesium, manganese, zinc, or other elemental additives or any combination of elements added.

(6) "Aseptic" is the process by which a sterile (aseptic) product (typically food or pharmaceutical) is packaged in a sterile container in a way that maintains sterility.

(7) "Aseptic tomato paste" means tomato paste packaged using aseptic preparation. Aseptic paste is normalized to 31 percent tomato soluble solids (TSS). Aseptic Paste Normalized to 31% TSS = (%TSS - 5.28)/(31 - 5.28)

(8) "Aseptic whole/diced tomato" means the sum of whole and diced tomatoes packaged using aseptic preparation. Sum of Whole and Diced = Whole Tomatoes + (Diced Tomatoes x 1.05))

(9) "Baked potato chip" means a potato chip made from potato dough that is rolled to a desired specified thickness, cut into a chip shape and then toasted in an oven.

(10) "Butter" means the product made by gathering the fat or fresh or ripened milk or cream into a mass, which also contains a small portion of other milk constituents.

(11) "Buttermilk" means the low-fat portion of milk or cream remaining after it has been churned to make butter.

(12) "Canned non-tomato additive" means a canned food product produced at a tomato processing facility that is not aseptic tomato paste, aseptic whole/diced, non-aseptic tomato paste, non-aseptic whole/diced, non-aseptic tomato juice, or canned non-tomato additive.

(13) "Calcium ammonium nitrate solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.

(14) "Carbon dioxide weighted tonne" or "CO_2 weighted tonne" or "CWT" means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes, stated in units of metric tons. The CWT 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 CWT 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 CWT factor is expressed as a value weighted relative to crude distillation.

(15) "Cheese" means a food product derived from milk that is produced in a wide range of flavors, textures, and forms by coagulation of the milk protein casein.

(16) "Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(17) "Cold rolled and annealed steel sheet" means steel that is cold rolled and then annealed. Cold rolling means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature. Annealing is a heat or thermal treatment process by which a previously cold-rolled steel coil is made more suitable for forming and bending. The steel sheet is heated to a designated temperature for a sufficient amount of time and then cooled.

(18) "Cold rolling of steel" means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature.

(19) "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 crude distillation.

(20) "Concentrated milk" means the liquid food obtained by partial removal of water from milk. The milk fat and total milk solids contents of the food are

not less than 7.5 and 25.5 percent, respectively. It is pasteurized, but is not processed by heat so as to prevent spoilage. It may be homogenized.

(21) "Container Glass pulled" means the quantity of glass removed from the melting furnace in the container glass manufacturing process where "container glass" is defined as glass products used for packaging.

(22) "Corn chip" is made from masa (ground corn dough) that is rolled to a specific thickness, cut into a chop shape, lightly toasted in an oven, and then deep fried.

(23) "Corn curl" is made from a deep-fried extrusion of masa (ground corn dough).

(24) "Cream" means that portion of milk, rich in milk fat, which rises to the surface of milk that is left standing or which is separated from milk by centrifugal force.

(25) "Crystal color concentrate" means precipitated solids extracted from fruits and vegetables whose uses are for altering the color of materials and/or food.

(26) "Deproteinized whey" means products manufactured through the cold ultrafiltration of sweet dairy whey, removing a portion of the protein from sweet whey to result in a non-hygroscopic, free-flowing and clean flavored powder containing greater than 80% carbohydrate (lactose) levels.

(27) "Diced Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. The tomatoes are peeled and diced, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

(28) "Distillate products" means a spirit made from the separation of alcohol and a fermented product.

(29) "Dolime" is calcined dolomite.

(30) "Dehydrated chili peppers" means chili peppers that have been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated chili peppers are processed to remove moisture to no more than 12% water by volume. Chili peppers are the fruit of plants from the genus *Capsicum*, members of the nightshade family, Solanaceae.

(31) "Dehydrated garlic" means garlic that has been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated garlic is processed to remove moisture to no more than 6.8% water by volume.

Garlic is an onion like plant *(Allium sativum)* having a bulb that breaks up into separable cloves with a strong distinctive odor and flavor.

(32) "Dehydrated onions" mean onions that have been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated onions are processed to remove moisture to no more than 5.5% water by volume. Onion (Allium cepa) is a plant that has a fan of hollow, bluish-green leaves and the bulb at the base of the plant begins to swell when a certain day-length is reached. In the autumn the foliage dies down and the outer layers of the bulb become dry and brittle.

(33) "Dehydrated parsley" means parsley that has been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated parsley is processed to remove moisture to no more than 5% water by volume. Parsley (Petroselinum crispum) is a species of *Petroselinum* in the family Apiaceae widely cultivated as an herb, a spice, and a vegetable.

(34) "Dehydrated spinach" means spinach that has been dehydrated in order to extend the shelf life and to concentrate the flavor. Dehydrated spinach is processed to remove moisture to no more than 7% water by volume. Spinach (*Spinacia oleracea*) is an edible flowering plant in the family of Amaranthaceae.

(35) "Ductile iron pipe" means pipe made of cast ferrous material in which a major part of the carbon content occurs as free graphite in a substantially nodular or spheroidal form. Pipes are used mainly to convey substances which can flow.

(36) "Evaporated milk" means the liquid food obtained by partial removal of water only from milk.

(37) "Fiberglass glass pulled" means the quantity of glass removed from the melting furnace in the fiberglass manufacturing process where "fiberglass" is defined as insulation products for thermal, acoustic and fire applications manufactured using glass.

(38) "Flat glass pulled" means the quantity of glass removed from the melting furnace in the flat glass manufacturing process where "flat glass" is defined as glass initially manufactured in a sheet form.

(39) "Freshwater diatomite filter aids" means inorganic mineral powders derived by processing freshwater diatomite which is fossilized single-celled algae found in lake beds. Filter aids are used in combination with filtration hardware to enhance filtration performance to separate unwanted solids from fluids.

(40) "Fried potato chip" means a thin slice of potato that is deep fried until crunchy.

(41) "Galvanized steel sheet" means steel coated with a thin layer of zinc to provide corrosion resistance for such products as garbage cans, storage tanks, or framing for buildings. Sheet steel normally must be cold-rolled prior to the galvanizing stage.

(42) "Granulated refined sugar" means white refined sugar (99.9% sucrose), made by dissolving and purifying raw sugar then drying it to prevent clumping.

(43) "Grape Juice concentrate" means the liquid from crushed grapes, botanical genus "Vitas", processed to remove water.

(44) "Gypsum" means a very soft sulfate mineral composed of calcium sulfate dihydrate, with the chemical formula $CaSO_4 \cdot 2H_2O$.

(45) "Horsepower tested" means the total horsepower of all turbine and generator set units tested prior to sale.

(46) "Hot rolled steel sheet" means steel produced from the rolling mill that reduces a hot slab into a coil of specified thickness at a relatively high temperature.

(47) "Lactose (milk sugar)" means a white to creamy white crystalline product, possessing a mildly sweet taste. It may be anhydrous, contain one molecule of water of hydration, or be a mixture of both forms.

(48) "Lager beer" means beer produced with bottom fermenting yeast strains, Saccharomyces uvarum (or carlsbergensis) at colder fermentation temperatures than ales.

(49) "Lead and lead alloy" means lead or the metal alloy that combines lead and other elements such as antimony, selenium, arsenic, copper, tin or calcium.

(50) "Limestone" means a sedimentary rock composed largely of the minerals calcite and aragonite, which are different crystal forms of calcium carbonate (CaCO3).

(51) "Liquid Color Concentrate" means a fluid extract from fruits and vegetables reduced by driving off water whose uses are for altering the color of materials and/or food.

(52) "Milk" means the lacteal secretion, practically free from colostrum, obtained by the complete milking of one or more healthy cows. Milk that is in final package form for beverage use shall have been pasteurized or ultra-pasteurized, and shall contain not less than 8 ¼ percent milk solids not fat and not less than 3 ¼ percent milk fat. Milk may have been adjusted by separating part of the milk fat from, or by adding cream to,

concentrated milk, dry whole milk, skim milk, concentrated skim milk, or nonfat dry milk. Milk may be homogenized.

(53) "Nitric acid" means HNO_3 of 100% purity.

(54) "Non-Aseptic tomato juice" means tomato juice packaged using methods other than aseptic preparation.

(55) "Non-Aseptic tomato paste" means tomato paste packaged using methods other than aseptic preparation. Non-Aseptic paste is normalized to 24 percent tomato soluble solids (TSS). Non-Aseptic Paste Normalized to 24% TSS = (%TSS - 5.28)/(24 - 5.28).

(56) "Non-Aseptic whole/diced tomato" means the sum of whole and diced tomatoes packaged using methods other than aseptic preparation. Sum of Non-Aseptic Whole and Diced = Whole Tomatoes + (Diced Tomatoes x 1.05).

(57) "Non-thermal enhanced oil recovery" or "non-thermal EOR" means the process of using methods other than thermal EOR, which may include water flooding or CO2 injection, to increase the recovery of crude oil from a reservoir.

(58) "Pickled steel sheet" means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides.

(59) "Pistachio" means the nuts of the pistachio tree of the genus *Pistacia vera* grown in the production area whether inshell or shelled.

(60) "Plaster" is calcined gypsum that is produced and sold as a finished product and is not used in the production of plasterboard at the same facility.

(61) "Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.

(62) "Poultry deli product" means the Products that contain a significant portion of pre-processed poultry and are prepared for human consumption (with or without additional cooking required), including sausages and corn dogs.

(63) "Powdered milk" means the manufactured dairy product made by evaporating milk to dryness.

(64) "Pretzel" is a type of baked bread product made from dough made into a desired shape. The dough is then passed through a caustic hot water bath and then baked in an oven.

(65) "Protein meal" means rendered product from poultry tissues including meat, viscera, bone, blood, and feathers.

(66) "Rare earth elements" means a set of seventeen chemical elements in the periodic table, specifically the fifteen lanthanides (Lanthanum, Cerium, Praseodymium, Neodymium, Promethium, Samarium, Europium, Gadolinium, Terbium, Dysprosium, Holmium, Erbium, Thulium, and Lutetium) plus Scandium and Yttrium.

(67) "Rare earth oxide equivalent" means the mass of oxide if all of the Rare Earth elements in the product are isolated and converted to their oxide form.

(68) "Recycled" refers to a material that is reused or reclaimed.

(69) "Recycled boxboard" means containers of solid fiber made from recycled fibers, including cereal boxes, shoe boxes and protective paper packaging for dry foods. It also includes folding paper cartons, set-up boxes, and similar boxboard products. Recycled boxboard is made from recycled fibers.

(70) "Recycled linerboard" means types of paperboard made from recycled fibers that meet specific tests adopted by the packaging industry to qualify for use as the outer facing layer for corrugated board, from which shipping containers are made.

(71) "Recycled medium" means the center segment of corrugated shipping containers, being faced with linerboard on both sides. Recycled medium is made from recycled fibers.

(72) "Salt" means sodium chloride, determined as chloride and calculated as percent sodium chloride, by the method prescribed in "Official Methods of Analysis of the Association of Official Analytical Chemists," 13th Ed., 1980, sections 32.025 to 32.030, under the heading "Method III (Potentiometric Method)."

(73) "Seamless rolled ring" means a metal product manufactured by punching a hole in a thick, round piece of metal, and then rolling and squeezing (or in some cases, pounding) it into a thin ring. Ring diameters can be anywhere from a few inches to 30 feet.

(74) "Skim milk" means non-fat or fat-free milk that results from the complete or partial removal of milk fat from milk.

(75) "Soda ash equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.

(76) "Steel produced using an electric arc furnace" means steel produced by an electric arc furnace or "EAF." EAF means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes.

(77) "Stucco" means hemihydrate plaster ($CaSO_4 \bullet \frac{1}{2}H_2O$) produced by heating ("calcining") raw gypsum, thereby removing three-quarters of its chemically combined water.

(78) "Sweetened condensed milk" means the food obtained by partial removal of water only from a mixture of milk and safe and suitable nutritive carbohydrate sweeteners. The finished food contains not less than 8 percent by weight of milk fat, and not less than 28 percent by weight of total milk solids. The quantity of nutritive carbohydrate sweetener used is sufficient to prevent spoilage. The food is pasteurized and may be homogenized.

(79) "Thermal enhanced oil recovery" or "thermal EOR" means the process of using injected steam to increase the recovery of crude oil from a reservoir.

(80) "Tin Plate" means thin sheet steel with a very thin coating of metallic tin. Tin plate also includes Tin Free Steel or TFS which has an extremely thin coating of chromium, metallic and oxide. Tin plate is used primarily in can making.

(81) "Tissue" means a class of papers which are characteristically gauzy in texture and, in some cases, fairly transparent. They may be glazed, unglazed, or creped, and are used for a variety of purposes. Examples of different types of tissue papers include sanitary grades such as toilet, facial, napkin, towels, wipes, and special sanitary papers.

(82) "Tomato Juice" is the liquid obtained from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. Tomato juice may contain salt, lemon juice, sodium bicarbonate, water, spices and/or flavoring.

(83) "Tomato Paste" is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. Tomato paste is prepared by concentrating tomato ingredients until the food contains not less than 24.0 percent tomato soluble solids.

(84) "Tomato soluble solids" means the sucrose value as determined by the method prescribed in the "Official Methods of Analysis of the Association of Official Analytical Chemists," 13th Ed., 1980, sections 32.014 to 32.016 and 52.012. For instances where no salt has been added, the sucrose value obtained from the referenced tables shall be considered the percent of tomato soluble solids. If salt has been added either intentionally or

through the application of the acidified break, determine the percent of such added sodium chloride as specified in the definition of salt. Subtract the percentage sodium chloride from the percentage of total soluble solids found (sucrose value from the refractive index tables) and multiply the difference by 1.016. The resultant value is considered the percent of "tomato soluble solids."

(85) "Waste gas" means a natural gas that contains a greater percentage of gaseous chemical impurities than the percentage of methane. For purposes of this definition, gaseous chemical impurities may include carbon dioxide, nitrogen, helium, or hydrogen sulfide.

(86) "Water absorption capacity" means the mass of water that is absorbed per unit mass of the test piece using the methodology specified by the ISO 12625-8:2010 except the humidity and temperature conditions shall be 50% relative humidity ±2%, and 23C ±1 C.

(87) "Whey permeate" means a source of dairy solids obtained by the removal of protein and some minerals and lactose from whey. The separation is accomplished by ultrafiltration and diafiltration. The product is labeled to reflect protein, ash and lactose content. The acidity of permeates may be adjusted by the addition of safe and suitable pH ingredients.

(88) "Whey protein concentrate" means the substance obtained by the removal of sufficient non-protein constituents from pasteurized whey so that the finished dry product contains > 25% protein. WPC is produced by physical separation techniques such as precipitation, filtration or dialysis. The acidity of WPC may be adjusted by the addition of safe and suitable pH adjusting ingredients.

(89) "Whole chicken and chicken parts" means the whole chicken or chicken parts (including breasts, thighs, wings) that are bone-in or deboned and packaged for wholesale or retail.

(90) "Whole Peeled Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit *Lycopersicum esculentum P.* Mill, of red or reddish varieties. The tomatoes are peeled but kept whole, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95103. Greenhouse Gas Reporting Requirements.

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(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* A facility operator may submit an abbreviated emissions data report under this article if all of the following conditions have been met: the facility operator does not have a compliance obligation under the cap-and-trade regulation during any year of the current compliance period; the operator is not subject to the reporting requirements of 40 CFR Part 98 specified in this article; and the facility total stationary combustion, process, fugitives and venting emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the information in paragraphs (1)-(7) below, and comply with the requirements specified in paragraphs (8)-(11) below:

(1) Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, geographic location, natural gas supplier name, natural gas supplier customer identification number, natural gas supplier service account identification number or other primary account identifier, and annual billed MMBtu (10 therms = 1 MMBtu).

(2) ~~Total f~~Facility GHG stationary combustion emissions ~~aggregated~~ for all stationary fuel combustion units and calculated according to any method in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O. If the facility includes multiple stationary fuel combustion units that belong to more than one unit type category listed in section 95115(h), the operator may report the multiple units in aggregate but must indicate the percentage of the aggregated fuel consumption attributed to each unit type category. In addition, if the facility includes an electricity generating unit, the facility operator must report the electricity generating unit separate from other stationary fuel combustion sources by following the unit aggregation provisions in sections 95112(b) and 95103(a)(6). The operator has the option of using engineering estimation or any combination of existing meters to meet the requirements of this paragraph.

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(6) For facilities with on-site electricity generation or cogeneration, the applicable information specified in sections 95112(a)-(b) of this article. Geothermal facilities must also report the information specified in section 95112(e). Operators of hydrogen fuel cells must report the information specified in section 95112(f).

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(8) Abbreviated emissions data reports submitted under this provision must be certified as complete and accurate no later than June 1 of each calendar year.

~~This requirement begins in 2012 for facilities who were required to report GHG emissions to ARB in 2011, and begins in 2013 for facilities not previously reporting to ARB~~.

(9) Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted ~~only~~ if an error is discovered after the submission of the emissions data report. If the ~~cumulative errors are found to exceed 5 percent of total CO_2e emissions, or if~~ error correction would cause the emissions total to exceed 25,000 metric tons of CO_2e, ~~in which case~~ a report that meets the full requirements of this article must be submitted within ninety days of discovery.

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(e) *Reporting Deadlines.* Except as provided in section 95103(a)(7)-(8), each facility operator or supplier must submit an emissions data report ~~for the previous calendar year~~ no later than April 10 of each calendar year. Each electric power entity must submit an emissions data report ~~for the previous calendar year~~ no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines.* The requirements of this paragraph apply to each reporting entity submitting an emissions data report ~~for the previous calendar year~~ that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, or each reporting entity that has or has had a compliance obligation under the cap-and-trade regulation in any year of the current compliance period. The requirements of this paragraph also apply to electric power entities that are electricity importers or exporters that have not met the requirements for cessation in section 95101(~~h~~i)(4). The reporting entity subject to verification must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subarticle 4 of this article. Such services must be completed and separate verification statements for emissions data and for product data, as applicable, must be submitted by the verification body to the Executive Officer by September 1 each year. Each reporting entity must ensure that these verification statements are submitted by this deadline. Contracting with a verification body without providing sufficient time to complete the verification statements by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR §98.3(f).

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(h) *Reporting in 2014.* For 2013 data reported in 2014, the following applies:

(1) Reporting entities may use best available methods for reporting and calculating the general requirements in section 95101(a)(1)(B)(8), the information regarding *de minimis* reporting for suppliers in section 95103(i), section 95103(j)(3), section 95103(k)(7)(C), section 95103(k)(11), section 95104(e), the information regarding mixed fuels in section 95115(c)(1), the information regarding mixed fuels in section 95115(e), the information

regarding the percentage of aggregated fuel consumption in section 95115(h), section 95115(k-l), and the information regarding fuel characteristic data elements and Table 1 in section 95129(c)(3). Reporting entities must adhere to the general provisions found in section 95101(a)(3), section 95101(h)-(i), section 95103(k)(7)(C), section 95103(k)(11), section 95103(l), the information regarding product data in section 95103(m), section 95103(m)(5), section 95103(n), and section 95104(d)(4);

(2) Abbreviated reporters may use best available methods for reporting and calculating the requirements in sections 95103(a)(1)-(2). Abbreviated reporters must adhere to the general provisions found in section 95103(a)(9);

(3) Operators of electricity generating facilities may use best available methods for reporting and calculating the requirements for the information regarding legacy contract transition assistance in section 95112(a), section 95112(a)(4)(C), section 95112(a)(5)(C), section 95112(b)(2), the information regarding on total thermal output in section 95112(b)(3), and section 95112(c)(3);

(4) Facility operators may use best available methods for reporting and calculating covered product data listed in section 95113(l)(4), the information regarding liquid hydrogen sold, on-purpose and by-product hydrogen gas in section 95114(j), section 95115(n)(5)-(17), the information regarding the tissue produced with water absorption capacity in 95119(d), the information regarding emulsion in sections 95156(a)(7)-(10), the information regarding a gas plant that produces less than 25 MMscf per day in section 95156(c), and section 95156(d);

(5) Operators of hydrogen plants who report under sections 95114(e)(1), (g), (i), (k), and (l) may use best available methods for calculating those reporting requirements;

(6) Operators of a lead production facility who report under section 95124 must use best available methods for calculating the reporting requirements;

(7) Suppliers of natural gas must adhere to the general provisions found in sections 95122(a)(2) and 95122(d)(2)-(6);

(8) Electric power entities must report 2013 electricity transactions (MWh) and emissions (metric tons of CO_2e) under the specifications of this article, including the requirements listed in sections 95111(a)(4)(A)(3), 95111(a)(5), 95111(b)(3), 95111(f)(5)(F) and 95111(g)(1)(N);

(9) All reporting entities and verification bodies must follow the requirements in sections 95130 to 95133, including those amendments outlined in sections 95130(a)(1)(D), 95130(a)(2), 95131(a)(2)(C), 95131(b)(8)(D), 95131(b)(8)(F), 95131(b)(9), 95131(b)(12)(B)-(C), 95131(b)(13), 95131(b)(14), 95131(c)(1), 95131(c)(3), 95131(c)(4), 95131(e), 95132(b)(1)(A),(C), 95132(d), 95133(a)-(c);

(10) Operators for the petroleum and natural gas systems sector subject to sections 95150(a)(2), including the definitional change to an onshore petroleum and natural gas systems facility in section 95102(a), 95153(y)(2)(C), 95157(c)(18)(B), 95157(c)(19)(H) must use best available methods for these reporting requirements;

(11) If a regulatory amendment is not specifically listed above, reporting entities must comply with the amendment for 2014 data reported in 2015.

~~*Reporting in 2012.* For emissions data reports due in 2012, facility operators may report 2011 emissions using applicable monitoring and calculation methods from 40 CFR Part 98. For entities not required to report 2011 emissions under 40 CFR Part 98, best available data and methods may be used for the 2011 data year. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012. For 2012 reports of 2011 emissions by facilities and suppliers, the missing data substitution requirements specified in this article that are different from the requirements of 40 CFR Part 98 do not apply; missing data for the 2012 report of 2011 emissions must be substituted according to the requirements of 40 CFR Part 98.~~

(i) *Calculation and Reporting of De Minimis Emissions.* A facility operator or supplier may designate as *de minimis* a portion of GHG emissions representing no more than 3 percent of a facility's total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstocks), not to exceed 20,000 metric tons of CO_2e. The operator or supplier may estimate *de minimis* emissions using alternative methods of the operator's choosing, subject to the concurrence of the verification body that the methods used are reasonable, not biased toward significant underestimation or overestimation of emissions, and unlikely to exceed the *de minimis* limits. The operator or supplier must separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The operator must determine CO_2 equivalence according to the global warming potentials provided in Table A-1 of 40 CFR Part 98.

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify and report all biomass-derived fuels as described in section 95852.2(a) of the cap-and-trade regulation. Except for operators that use the methods of 40 CFR §98.33(a)(2)(iii) or §98.33(a)(4), the operator or supplier must separately identify, calculate, and report all direct emissions of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95112 and 95115 for facilities, and sections 95121 and 95122 for suppliers. A biomass-derived fuel not listed in section 95852.2(a) of the cap-and-trade regulation must be identified as non-exempt biomass-derived fuel. For a fuel listed under section 95852.2 of the cap-and-trade regulation, reporting entities must also meet the verification requirements in section 95131(i) of this article and the requirements of section 95852.1.1 of the cap-and-trade regulation, or the fuel must be identified as non-exempt biomass-derived fuel. Carbon dioxide combustion emissions from non-exempt biomass-derived fuel will be identified as non-exempt biomass-derived CO_2. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.2 of the cap-and-trade regulation.

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(3) When reporting biomethane, the operator or supplier who is reporting biomass emissions from biomethane fuel must also report the following information for each contracted delivery:

(A) Name and address of the biomethane vendor from which biomethane is purchased;
(B) Annual MMBtu delivered by each biomethane vendor.

The operator must also report the name, address, and facility type of the facility from which the biomethane is produced. In addition, relevant documentation including invoices, shipping reports, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts must be made available for verifier or ARB review to demonstrate the receipt of eligible biomethane.

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(k) *Measurement Accuracy Requirement.* The operator or supplier subject to the requirements of 40 CFR §98.3(i) must meet those requirements for data used for calculating non-covered emissions and non-covered product data, except as otherwise specified in this paragraph. In addition, the following accuracy requirements apply to data used for calculating covered emissions and covered product data. The operator or supplier with covered product data or covered emissions equal to or exceeding 25,000 metric tons of CO_2e or a compliance obligation under the cap-and-trade regulation in any year of the current compliance period must meet the requirements of paragraphs (k)(1)-(10) below for calibration and measurement device accuracy. Inventory measurement, stock measurement, or tank drop measurement methods are subject to paragraph (11) below. The requirements of paragraphs (k)(1)-(11) apply to fuel consumption monitoring devices, feedstock consumption monitoring devices, process stream flow monitoring devices, steam flow devices, product data measuring devices, mass and fluid flow meters, weigh scales, conveyer scales, gas chromatographs, mass spectrometers, calorimeters, and devices for determining density, specific gravity, and molecular weight. The provisions of paragraph (k)(1)-(11) do not apply to: stationary fuel combustion units that use the methods in 40 CFR §98.33(a)(4) to calculate CO_2 mass emissions; emissions reported as *de minimis* under section 95103(i); and devices that are solely used to measure parameters used to calculate emissions that are not covered emissions or that are not covered product data. The provisions of paragraphs (k)(1)-(9) and (k)(11) do not apply to stationary fuel combustion units that use the methods in 40 CFR Part 75 Appendix G §2.3 to calculate CO_2 mass emissions, but the provisions in paragraph (k)(10) are applicable to such units.

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(7) The requirements of section 95103(k) do not apply under the following circumstances:

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(C) Non-financial transaction meters used by Public Utility Gas Corporations for purposes of reporting natural gas supplier emissions are exempt from the calibration requirements in sections 95103(k)(1)-(6) if the supplier can demonstrate that the meters are operated and maintained in conformance with a standard that meets the measurement accuracy requirements of the California Public Utilities Commission General Order 58A (1992).

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(9) In cases of continuously operating units and processes where calibration or inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the Executive Officer that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of section 95103(k)(6). The Executive Officer must approve any postponement of calibration or required recalibration beyond January 1, 2012.

(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date ~~except in 2012, where the postponement request must be received by the reporting deadline in section 95103(e)~~. The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to ARB within ten (10) working days of a request by ARB.

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(11) When using an inventory measurement, stock measurement, or tank drop measurement method to calculate volumes and masses and process throughputs in sections 95113(l)(3)-(4), the method must be accurate to ±5 percent for the time periods required by this article, including annually for covered product data. Techniques used to quantify amounts stored at the beginning and end of these time periods are not subject to the calibration requirements of this section. Uncertainties in beginning and end amounts are subject to verifier review for material misstatement under section 95131(b)(12) of this article. If any devices used to measure inputs and outputs do not meet the requirements of paragraphs (1)-(10) above, the verifier must account for this uncertainty when evaluating material misstatements. Reported values must be calculated using the following equations:

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(l) *Reporting and Verifying Product Data*. The reporting entity must separately identify, quantify, and report all product data as specified in sections 95110-95124~~3~~ and 95156 of this article. It is the responsibility of the reporting entity to obtain verification services for the product data. Product data will be evaluated for conformance and material misstatement independent of GHG emissions data.

Covered product data is evaluated for material misstatement and conformance, while the remaining reported product data is evaluated for conformance only. Reporting entities may elect to exclude inaccurate covered product data. Reporting entities that elect to exclude inaccurate covered product data must report a description of the excluded data and an estimated magnitude using best available methods. The excluded covered product data will not be used for the material misstatement assessment or for the total covered product data variable described in section 95131(b)(12)(A). Operators of cement plants may not exclude covered product data.

(m) *Changes in Methodology*. Except as specified below, where this article permits a choice between different methods for the monitoring and calculation of GHGs and product data, the operator or supplier must make this choice by January 1, 2013, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative calculation method is approved in advance by the Executive Officer.

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(3) When proposing a change in a monitoring or calculation method, an operator or supplier must indicate why the change in method is being proposed, and include~~provide~~ a demonstration of differences in estimated emissions under the two methods.

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(5) When regulatory changes impose new or revised reporting requirements or calculation methods on an operator or supplier, the monitoring and calculation method must be in place on January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.

(n) *Changes in Ownership or Operational Control*. If a reporting entity undergoes a change of ownership or operational control, the following requirements apply regarding notifications to ARB and reporting responsibilities.

(1) *ARB Notifications*. Prior to the change of ownership or operational control, the previous owner or operator of the reporting entity and the new owner or operator of the reporting entity must provide the following information to ARB. Required information must be submitted to the ARB email account: ghgreport@arb.ca.gov

(A) The previous owner or operator must notify ARB via email of the ownership or operational control change including the name of the new owner or operator and the date of the ownership or operational control change.

(B) The new owner or operator must notify ARB via email of the ownership or operational control change, including the following information:

1. Previous owner or operator;
2. New owner or operator;
3. Date of ownership or operator change.
4. Name of a new Designated Representative pursuant to section 95104(b) for the affected entity's account in the California Reporting Greenhouse Gas Reporting Tool (Cal e-GGRT) specified in section 95104(f);

(2) *Reporting Responsibilities.* The owner or operator of record at the time of a reporting or verification deadline specified in this article has the responsibility for complying with the requirements of this article, including certifying that the emissions data report is accurate and complete, obtaining verification services, and completing verification.

(A) The owner or operator of record at the time of a reporting deadline is responsible for submitting the emissions data report covering the complete calendar year data.
(B) If an ownership change takes place during the calendar year, reported data must not be split or subdivided for the year, based on ownership. A single annual data report must be submitted for the entity by the current owner or operator. This report must represent required data for the entire, calendar year.
(C) Previous owners or operators are required to provide data and records to new owners or operators that is necessary and required for preparing annual emissions data reports required by this article.

(or)*Addresses.* The following address shall be substituted for the addresses provided in 40 CFR §98.9 for both U.S. mail and package deliveries:

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95104. Emissions Data Report Contents and Mechanism.

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(d) *Facility Level Energy Input and Output.* The operator must include in the emissions data report information about the facility's energy acquisitions and energy provided or sold as specified below. For the purpose of reporting under this paragraph, the operator may exclude any electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility. The operator may also exclude electricity consumed by operations or activities that do not generate any emissions, energy outputs, or products that are covered by this article, and that are neither a part of nor in support of electricity generation or any

industrial activities covered by this article. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

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(4) Thermal energy provided or sold to entities outside of the facility boundary: the operator must report the amount of thermal energy provided or sold (MMBtu), the names and ARB identification number of each end-user as applicable, and the type of unit that generates the thermal energy. If section 95112 applies to the operator, the operator must follow the requirements of section 95112(a)(5) in reporting the thermal energy generated by cogeneration or bigeneration units, and if applicable, also separately report the information required in paragraph 95104(d)(4) for the thermal energy provided or sold that is not generated by cogeneration or bigeneration units.

If the facility boundary includes more than one cogeneration system, boiler, or steam generator, and each unit/system or each group of units produces thermal energy for different particular end-users or on-site industrial processes and operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions, and by the type of thermal energy product provided.

(e) *Increase in Facility Criteria Pollutant and Toxic Air Contaminant Emissions.* The operator of a facility identified in section 95101(a)(1)(A)-(B) that is subject to the cap-and-trade regulation must include the following information in the emissions data report:

(1) Whether a change in the facility's operations or status potentially resulted in an increase in emissions of criteria pollutants or toxic air contaminants in relation to the previous data year.
(2) Specify which of the following reason(s) would be the cause of the increase in criteria pollutant, and/or toxic air contaminant emissions:

(A) Change in production;
(B) Changes in facility operations in order to comply with:

1. The cap-and-trade regulation;
2. Other air pollution regulations;
3. Other regulations, not related to air pollution or greenhouse gases;

(C) Changes in efficiency due to:

1. Process or material changes;
2. The addition of control equipment;
3. Other efficiency measures;

(D) Other.

(3) A narrative description of how each reason identified in section 95104(e)(2)caused the increase in emissions. Include in this description any changes in your air permit status.

(fe) *Reporting Mechanism.* Reporting entities shall submit emissions data reports, and any revisions to the reports, through the California Air Resources Board's (ARB) Greenhouse Gas Reporting Tool, or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of data required by ARB's Mandatory Reporting Regulation and Cost of Implementation Fee Regulation. Reporting entities are not responsible for reporting data required under this article that is not specified for reporting in the reporting tool.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95105. Recordkeeping Requirements.

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(c) *GHG Monitoring Plan for Facilities and Suppliers.* Each facility operator or supplier that reports under 40 CFR Part 98, each facility operator or supplier with ~~covered~~ emissions equal to or exceeding 25,000 MT CO_2e (including biomass-derived CO_2 emissions and geothermal emissions), and each facility operator or supplier with a compliance obligation under the cap-and-trade regulation in any year of the current compliance period, must complete and retain for review by a verifier or ARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5). For facilities, the Plan must also include the following elements, as applicable:

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(7) Records of the most recent orifice plate inspection performed according to the requirements of ISO 5167-2 (2003), section 5, or AGA Report No 3 (2003) Part 2, which ~~is~~ are hereby incorporated by reference.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

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Subarticle 2. Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

§ 95110. Cement Production.

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(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.85 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities.

The electric power entity who is required to report under section 95101 of this article must comply with the following requirements.

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

***

(4) *Imported Electricity from Specified Facilities or Units.* The electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity. When reporting imported electricity from specified facilities or units, the electric power entity must disaggregate electricity deliveries and associated GHG emissions by facility or unit and by first point of receipt, as applicable. The reporting entity must also report total GHG emissions and MWh from specified sources and the sum of emissions from specified sources explicitly listed as not covered pursuant to section 95852.2 of the cap-and-trade regulation. <u>The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity from the source through the market path.</u>

(A) Claims of specified sources of imported electricity, defined pursuant to section 95102(a), are calculated pursuant to section 95111(b), must meet the requirements in section 95111(g), and must include the following information:

1. *Measured at Busbar.* The amount of imported electricity from specified facilities or units as measured at the busbar; and
2. *Not Measured at Busbar.* If the amount of imported electricity deliveries from specified facilities or units as measured at the busbar is not ~~known~~ provided, report the amount of imported electricity as measured at the first point of delivery in California, including estimated transmission losses as required in section 95111(b), and the reason why measurement at the busbar is not known.
3. Supporting documentation must be provided for busbar claims.

(5) *Imported Electricity Supplied by Asset-Controlling Suppliers.* The reporting entity must separately report imported electricity supplied by asset-controlling suppliers recognized by ARB. ~~The asset-controlling supplier must be identified on the physical path of NERC e-Tags as the PSE at the first point of receipt regardless of whether the reporting entity and asset-controlling supplier are adjacent in the market path.~~ The reporting entity must:

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(B) ~~Report delivered electricity as specified and not as unspecified;~~Report asset-controlling supplier power that was not acquired as specified power, as unspecified power;

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(D) Report GHG emissions calculated pursuant to section 95111(b), ~~including~~ using the transmission ~~losses~~ factor of 1.02 in all instances.

(E) *Tagging ACS Power.* To claim power from an asset-controlling supplier, the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner, with the exception of path outs. Path outs are excess power, originally procured as part of a 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.

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(12) *Imported Electricity Supplied by System Power Supplier.* The reporting entity must separately report imported electricity supplied by system power suppliers identified by ARB, when the system power supplier is identified on the physical path of NERC e-Tags as the PSE at the first point of receipt. The reporting entity must:

(A) Report the system power supplier standardized PSE acronym or code, full name, and the ARB identification number;
(B) Report system power that was not acquired as specified power, as unspecified power;
(C) Report delivered electricity from system power suppliers as measured at the first point of delivery in the state of California; and,
(D) Report GHG emissions calculated pursuant to section 95111(b)(5), including using the transmission losses factor of 1.02 in all instances.

(b) *Calculating GHG Emissions.*

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(3) *Calculating GHG Emissions of Imported Electricity Supplied by ~~Specified~~ Asset-Controlling Suppliers.* Based on annual reports submitted to ARB pursuant to section 95111(f), ARB will calculate and publish on the ARB Mandatory Reporting website the system emission factor for all asset-controlling suppliers recognized by the ARB. The reporting entity must calculate emissions for electricity supplied using the following equation:

$$CO_2e = MWh \times TL \times EF_{ACS}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from ARB-recognized asset-controlling suppliers (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Asset-Controlling Supplier-~~specific~~ system emission factor published on the ARB Mandatory Reporting website (MT CO_2e/MWh). ARB will assign the system emission factors for all asset-controlling suppliers based on a previously verified GHG report submitted to ARB pursuant to section 95111(f). The supplier-specific system emission factor is calculated annually by ARB. The calculation is derived from data contained in annual reports submitted pursuant to section 95111(f) that have received a positive or qualified positive verification statement. The emission factor is based on data from two years prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

~~TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.~~

The Executive Officer shall calculate the system emission factor for asset-controlling suppliers using the following equations:

EF_{ACS} = Sum of System Emissions MT of CO_2e / Sum of System MWh

Sum of System Emissions, MT of CO_2e = $\Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$

Sum of System MWh = $\Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} - \Sigma SE_{sp}$

Where:

ΣE_{asp} = *Emissions from Owned Facilities*. Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier's fleet, consistent with section 95111(b)(2) (MT of CO_2e).

ΣEG_{asp} = *Net Generation from Owned Facilities*. Sum of net generation for each specified facility/unit in the asset-controlling supplier's fleet for the data year as reported to ARB under this article (MWh).

PE_{sp} = *Electricity Purchased from Specified Sources*. Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh). For purposes of this calculation, treaty power is included in this variable.

PE_{unsp} = *Electricity Purchased from Unspecified Sources*. Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

SE_{sp} = *Electricity Sold from Specified Sources*. Amount of wholesale electricity sold from ~~a~~ specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with section 95111(b)(2) (MT CO_2e/MWh).

EF_{unsp} = Default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

(4) *Calculating GHG Emissions of Imported Electricity for Multi-jurisdictional Retail Providers.*

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(5) *Calculating GHG Emissions of Imported Electricity Supplied by System Power Suppliers.* The Executive Officer shall calculate and publish, on the ARB Mandatory Reporting website prior to each calendar year, the system emission factor for all system power suppliers identified by ARB, for use in determining

emissions associated with system power. The following equation shall be used for this purpose:

$EF_{sy} = E_{sy} / EG_{sy}$

Where:

EF_{sy} = CO_2e emission factors for system power recognized by ARB for the report year (MT of CO_2e/MWh). The emission factor is based on data from the year prior to the reporting year.

E_{sy} = CO_2e emissions for a system for the report year (MT of CO_2e).

EG_{sy} = Net generation from a system for the report year (MWh).

(A) For system power suppliers who voluntarily report under this article, E_{sy} shall be equal to the sum of CO_2e emissions reported pursuant to section 95111(b)(5).

(B) For the system power calculation, the Executive Officer may use publicly available information, information voluntarily made available, or other information accessible by ARB.

(~~5~~6) Calculation of Covered Emissions. For imported electricity with covered emissions as defined pursuant to section 95102(a), the electric power entity must calculate and report covered emissions pursuant to the equation in 95852(b)(1)(B) of the cap-and-trade regulation and include the following information:

***

(c) *Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.* Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in sections 95111(a)-(b) and (g).

(1) Retail providers must report California retail sales. A retail ~~providers~~ provider who is required only to report retail sales may choose not to apply the verification requirements specified in section 95103, if the retail provider deems the emissions data report non-confidential.

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(f) *Requirements for Asset-Controlling Suppliers.* Owners or operators of electricity generating facilities or exclusive marketers for certain generating facilities may apply for an asset-controlling supplier designation from ARB. Approved asset-controlling suppliers may request that ARB calculate a supplier-specific emission factor pursuant to section 95111(b)(3). To apply for asset-controlling supplier designation, the applicant must:

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(5) To apply for and maintain asset-controlling supplier status, the entity shall submit as part of its emissions data report the following information, annually:

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(E) A list and description of electricity generating facilities for which the reporting entity is a generation providing entity pursuant to 95102(a), ~~and~~

(F) For treaty power, the total amount of electricity received under the treaty; and

(~~F~~G) An attestation, in writing and signed by an authorized officer of the applicant, as follows:

***

(g) *Requirements for Claims of Specified Sources of Electricity, and for Eligible Renewable Energy Resources in the RPS Adjustment and System Power Supplier Sources*.

Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with ARB pursuant to subsection 95111(g)(1) and by February 1 following each data year to obtain associated emission factors calculated by ARB for use in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to subsection 95111(g)(2)-(5) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)~~(5)~~(6), pursuant to section 95852(b)(4) of the cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to subsection 95111(g)(1) in the emissions data report. Prior registration and subsection 95111(g)(2)-(5) do not apply to RPS adjustments. Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified within 45 days following the emissions data report due date. Each reporting entity claiming system power supplier sources for imported electricity must register its anticipated specified sources with ARB pursuant to section 95111(g)(6) and by July 1 prior to each data year to obtain associated emission factors calculated by ARB for use in the emissions data report required to be submitted by June 1 following the data year.

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

***

(N) For verification purposes, retain meter generation data to document that the power claimed by the reporting entity was generated by the facility or unit ~~at the time the power was directly delivered~~.

***

(6) *Registration Information for System Power Sources.* The following information is required:

(A) The proposed system power supplier;
(B) A description of the system power source as well as the publicly available information that ARB may utilize in a system emission factor calculation;
(C) Information on current and historical NAESB/NERC e-tagging practices for the system power supplier.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95112. Electricity Generation and Cogeneration Units.

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(a) *Information About the Electricity Generating Facility*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating facility is required to include in the emissions data report the information listed in this paragraph, unless otherwise specified in paragraphs (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in section 95112(a)(4)-(6) is optional for facilities that do not provide or sell any generated energy outside of the facility boundary. However, facility operators that are applying for the legacy contract transition assistance under the cap-and-trade regulation must always report the information in section 95112(a)(4)-(6), even if they do not provide or sell any generated energy outside of the facility boundary.

***

(4) The disposition of generated electricity in MWh, reported at the facility-level, including for each of the following disposition categories, if applicable:

(A) *Generated Electricity For Grid.* Generated electricity provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid. The operator must report the name of the retail provider or electricity marketer;
(B) *Generated Electricity For Other Users.* Generated electricity provided or sold directly to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, and ARB ID if applicable;
(C) *Generated Electricity For On-Site Industrial Applications Not Related to Electricity Generation.* If the facility includes industrial processes or operations that are neither in support of or a part of the power generation

system, report the amount of generated electricity used by those on-site industrial processes or operations.

Separately report the amount of generated electricity that is used to produce cooling energy if:

1. The facility provides cooling energy (e.g., chilled water) to a particular end-user outside of the facility boundary; or
2. The facility includes on-site industrial processes or operations that are neither in support of or a part of the power generation system, and a portion of the generated electricity is used to produce cooling energy for such on-site industrial process or operations.

If the facility includes equipment that utilizes generated electricity to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, account for such electricity as a part of the difference between gross generation and net generation (parasitic load) pursuant to section 95112(b)(2).

If a facility includes more than one electricity generating unit or cogeneration system, and each unit/system or each group of units generate electricity for different particular end-users or retail providers or electricity marketers, the operator must separately report the disposition of generated electricity by unit/system or by group of units. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated electricity from the group of units is provided to the same destination.

(5) The operator of a cogeneration or bigeneration unit must report ~~T~~the disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit ("generated thermal energy"), ~~if applicable~~, reported at the facility-level, including for each of the following disposition categories, if applicable:

(A) *Generated Thermal Energy For Other Users.* Thermal energy provided or sold to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, ARB ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user.

(B) *Parasitic Steam Use.* Thermal energy used for supporting power production that has been included in the quantity reported under paragraph 95112(b)(3) but that is not accounted for in the quantities reported under paragraphs 95112(a)(5)(A) and (C). This thermal energy

quantity must not include steam directly used for power production, such as the steam used to drive a steam turbine generator to generate electricity. Activities for supporting power generation may include steam used for power augmentation, NO_x control, sent to a de-aerator, or sent to a cooling tower.

(C) *Generated Thermal Energy For On-Site Industrial Applications Not Related to Electricity Generation.* If the facility includes other industrial processes or operations that are neither in support of or a part of the electricity generation or cogeneration system, report the amount of generated thermal energy that is used by those on-site industrial processes or operations and heating or cooling applications. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations. This quantity does not include the amount of thermal energy generated by equipment that is not an integral part of the cogeneration unit.

Separately report the amount of generated thermal energy that is used to produce cooling energy or distilled water if:

1. The facility provides cooling energy (e.g., chilled water) or distilled water to a particular end-user outside of the facility boundary, or
2. The facility includes on-site industrial processes or operations that are neither in support of or a part of the power generation system, and a portion of the generated thermal energy is used to produce cooling energy or distilled water for such on-site industrial process or operations.

If the facility includes equipment that utilizes generated thermal energy to produce cooling (e.g., absorption chiller) for the sole purpose of maintaining temperature in the electricity generation or cogeneration system, follow section 95112(a)(5)(B) in reporting such use of generated thermal energy.

If a facility includes more than one cogeneration or bigeneration unit/system, and each unit/system or each group of units generate thermal energy for different particular end-users or on-site industrial processes or operations, the operator must report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions. For the purpose of separate reporting of disposition, the operator may group similar units together if the generated thermal energy from the group of units is provided to the same destination.

(6) For the first year of reporting ~~in 2012 or later~~, operators of cogeneration or bigeneration units must submit a simplified block diagram depicting the following, as applicable: individual equipment included in the generation

system (e.g. turbine, engine, boiler, heat recovery steam generator); direction of flows of energy specified in paragraphs (a)(4)-(5), (b)(2)-(4) and (b)(7)-(8) of this section, with the forms of energy carrier (e.g. steam, water, fuel) labeled; and relative locations of fuel meters and other fuel quantity measurements. If the cogeneration or bigeneration system is modified after the initial submission of the diagram ~~in 2012~~, the operator must resubmit an updated diagram to ARB.

(b) *Information About Electricity Generating Units.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit must include in the emissions data report the information listed in this paragraph. For aggregation of electricity generating units, the operator must meet the applicable criteria in 40 CFR §98.36(c)(1)-(4), unless otherwise specified in sections 95115(h) and 95112(b). For an electricity generation system (a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators), the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to ARB. Operators of Part 75 units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40 CFR §98.36(d)(1)(i). If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 95115(h). Operators of geothermal facilities, hydrogen fuel cells, and renewable electricity generating units must follow paragraph (e), (f), or (g) of this section, whichever is applicable, instead of paragraph (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in section 95112(b)(4)-(6) except for any fuels combusted for supplemental firing as specified in section 95112(b)(7).

***

(2) Net and gross power generated, in megawatt hours (MWh). <u>The difference between net generation and gross generation is the parasitic load of electricity generation or cogeneration. The net generation quantity represents the amount of generated electricity that can be provided to the disposition categories in section 95112(a)(4).</u>

(3) If the unit is a cogeneration or bigeneration unit, the operator must report the total thermal output (MMBtu), as defined in section 95102, that was generated by the unit <u>and can be potentially utilized in other industrial operations that are not electricity generation</u>. Exclude from this quantity the heat content of returned condensate and makeup water and steam used to drive a steam turbine generator for electricity generation. <u>The total thermal output quantity represents the amount of generated thermal energy that can be provided to the thermal energy disposition categories in section 95112(a)(5).</u>

***

(c) *Emissions from Fuel Combustion and Sorbent.* When calculating CO_2, CH_4, and N_2O emissions from fuel combustion, the operator who is subject to Subpart C or D of 40 CFR Part 98 must use a method in 40 CFR §98.33(a)(1)-(4) as specified by fuel type in section 95115 of this article, except that for CO2 emissions the operator who is subject to Subpart D of 40 CFR Part 98 may elect instead to follow the provisions in 40 CFR §98.43, within the limitations of section 95103(m) of this article.

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(2) The operator of a Subpart D unit with contractual deliveries of biomethane or biogas is subject to the requirements in section 95131(i) of this article and must follow the procedure in sections 95115(e)(4)-(5) in calculating emissions from biomethane, biogas, and natural gas.

(3) The operator of a Subpart D unit who reports CO_2 emissions using emission calculation methods specified in 40 CFR Part 75, and who operates a unit with a wet flue gas desulfurization system, must indicate the portion of the total reported CO_2 emissions that is generated from sorbent injection for acid gas removal.

***

(f) *Hydrogen Fuel Cells.* Operators of stationary hydrogen fuel cell units ~~that produce hydrogen on-site must report information on the fuels or feedstocks used in hydrogen production. The operator~~ must include the following information in the annual GHG emissions data report:

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(5) CO_2 emissions from the hydrogen fuel cell, calculated using one of the following methods:

(A) The fuel and feedstock mass balance approach in 40 CFR 98.163(b). If the fuel's carbon content is not known, the facility operator may use the default carbon content percentage value listed in Table 1 of section 95129(c).

(B) For natural gas and biogas, if the fuel heat input is measured by the facility operator or by the fuel supplier, the operator may use the following equation to estimate emissions.

CO_2 (MT/year) = H (MMBtu/year) x EF (kg CO_2/MMBtu) x 0.001 (MT/kg)

Where
CO_2 = Annual CO_2 emissions from fuel and feedstock consumption (metric tons/year)
H = Total fuel heat input for the year (MMBtu/year)
EF = Default CO_2 emission factor. Use 53.02 kg CO_2/ MMBtu for natural gas. Use 52.07 kg CO_2/MMBtu for biogas.
0.001 = Conversion factor from kg to metric tons.

(C) For biogas fuels, the facility operator may elect to use the best available estimation and engineering estimation approach to calculate emissions.

(h) *Missing Data Substitution Procedures.* To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of ~~40 CFR §98.35 when reporting in 2012, and~~ section 95129 of this article ~~when reporting in 2013 and later years~~. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95113. Petroleum Refineries.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart Y of 40 CFR Part 98 (40 CFR §§98.250 to 98.258) in reporting emissions and other data from petroleum refineries to ARB, except as otherwise provided in this section. Petroleum refinery operators and refiners are considered separate reporting entities for the purposes of this article.

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(k) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.255 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(2) below.

***

(l) *Additional Product and Process Data.*

(1) *Finished Products.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR 98, each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, barrels for liquid products, short tons for solid products), and calcined coke (short tons). For calcined coke, specify whether the calciner is integrated with the petroleum refinery operation. Among the products reported, only calcined coke and primary refinery products will be subject to review for material misstatement under the requirements of section 95131(b)(12). Primary refinery products will be evaluated for conformance and assessment of material misstatement through 2014 data year verifications. Beginning with 2015 data reported in 2016, primary refinery products will be evaluated for conformance only and will not be evaluated for material misstatement.

(A) ~~For calcined coke, the operator may voluntarily report the annual short tons of calcined coke for calendar years 2011 and 2012. If the operator chooses to report this 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, t~~The operator must report and verify the annual short tons of calcined coke.

(2) *Energy Intensity Index.* For refineries that participate in the Solomon Energy Reviews, the operator must report its most current Solomon EII values for the applicable data year. Each refinery operator must demonstrate to the verifier that the Solomon EII value reported is the correct value by providing documentation from Solomon & Associates.

(3) *CO_2 Weighted Tonne (CWT) Calculation.*

(A) *Reporting of CWT Throughput Functions.* ~~For data years 2013 and later~~ tThe operator must report values for the CWT functions listed in Table 1 of this section. Report quantities of net fresh feed (F), reactor feed (R, includes recycle), product Feed (P), or synthesis gas production for POX units (SG) as indicated. Beginning with data year 2013, CWT is considered covered product data and subject to material misstatement.

(B) *Total facility CWT.* The total facility CWT production value must be calculated according to the following formula.

$$CWT = \sum CWT_{Factor} * Throughput$$

Where:

"CWT" = The total amount of CO_2 Weighted Tonnes from a petroleum refinery.

"CWT_{Factor}" = The CWT factor for each process found in Table 1 of this section.

"Throughput" = The reported value for each CWT function identified in Table 1 of this section reported pursuant to section 95113(~~m~~l)(3)(A).

(C) *Units and Accuracy.* Report annual volume in both barrels and mass, in thousands of metric tons, unless other basis units are indicated in column 3 of Table 1 of this section. In order to meet the desired accuracy for CWT, throughput values reported in thousands of metric tons per year must use a certain number of decimals depending on the magnitude of the CWT factor:

~~(i)~~1. For factors up to 1.99:	0 decimals
~~(ii)~~2. For factors between 2.00 and 19.99:	1 decimal
~~(iii)~~3. For factors between 20.00 and 99.99:	2 decimals
~~(iv)~~4. For factors above 100.00:	3 decimals

(D) *Density.* The density of each throughput must be known for purposes of converting each throughput from barrel to mass units. If the throughput has a known density, a default value may be used. The default value reference must be retained for verification purposes. If the throughput is not known, the measurements must follow the requirements of section 95103(k).

(4) *Complexity Weighted Barrel (CWB) Calculation.*

(A) *Reporting of CWB Throughput Functions.* The operator must report annual volume in barrels for each applicable throughput in Table 1, unless other units are listed in column 3 of Table 1 of this section. Beginning with data year 2013, CWB is considered covered product data and subject to material misstatement.

(B) *Total facility CWB.* The total facility CWB production must be calculated according to the following formula.

$$CWB = \sum CWB_{Factor} * Throughput$$

Where:

"CWB" = The total amount of complexity weighted barrels from a petroleum refinery.

"CWB_{Factor}" = 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(l)(4)(A).

Table 1. ~~CWT~~ Functions and Factors

~~CWT~~ function	***Description***	***Basis (Thousands of Metric Tons/Year)***	***~~CWT~~ factor***

Atmospheric Crude Distillation	Mild Crude Unit, Standard Crude Unit	F	1.00
Vacuum Distillation	Mild Vacuum Fractionation, Standard Vacuum Column, Vacuum Fractionating Column Vacuum distillation factor also includes average energy and emissions for Heavy Feed Vacuum (HFV) unit. Since this is always in series with the MVU, HFV capacity is not counted separately	F	0.85
Solvent Deasphalting	Conventional Solvent, Supercritical Solvent	F	2.45
Visbreaking	Atmospheric Residuum (w/o a Soaker Drum), Atmospheric Residuum (with a Soaker Drum), Vacuum Bottoms Feed (w/o a Soaker Drum), Vacuum Bottoms Feed (with a Soaker Drum) Visbreaking factor also includes average energy and emissions for Vacuum Flasher Column (VAC VFL) but capacity is not counted separately	F	1.40
Thermal Cracking	Thermal cracking factor also includes average energy and emissions for Vacuum Flasher Column (VAC VFL) but capacity is not counted separately	F	2.70
Delayed Coking	Delayed Coking	F	2.20
Fluid Coking	Fluid Coking	F	7.60
Flexicoking	Flexicoking	F	16.60
Coke Calcining	Vertical-Axis Hearth, Horizontal-Axis Rotary Kiln	P	12.75
Fluid Catalytic Cracking	Fluid Catalytic Cracking, Mild Residuum Catalytic Cracking, Residual Catalytic Cracking	F	5.50
Other Catalytic Cracking	Houdry Catalytic Cracking, Thermofor Catalytic Cracking	F	4.10
Distillate/Gasoil Hydrocracking	Mild Hydrocracking, Severe Hydrocracking, Naphtha Hydrocracking	F	2.85
Residual Hydrocracking	H-Oil, LC-Fining™ and Hycon	F	3.75

Naphtha/Gasoline Hydrotreating	Benzene Saturation, Desulphurisation of C4–C6 Feeds, Conventional Naphtha H/T, Diolefin to Olefin Saturation, Diolefin to Olefin Saturation of Alkylation Feed, FCC Gasoline hydrotreating with minimum octane loss, Olefinic Alkylation of Thio S, S-Zorb™ Process, Selective H/T of Pygas/Naphtha, Pygas/Naphtha Desulphurisation, Selective H/T of Pygas/Naphtha Naphtha hydrotreating factor includes energy and emissions for Reactor for Selective H/T (NHYT/RXST) but capacity is not counted separately	F	1.10
Kerosene/Diesel Hydrotreating	Aromatic Saturation, Conventional H/T, Solvent aromatics hydrogenation, Conventional Distillate H/T, High Severity Distillate H/T, Ultra-High Severity H/T, Middle Distillate Dewaxing, S-Zorb™ Process, Selective Hydrotreating of Distillates	F	0.90
Residual Hydrotreating	Desulphurisation of Atmospheric Residuum, Desulphurisation of Vacuum Residuum	F	1.55
VGO Hydrotreating	Hydrodesulphurisation/denitrification, Hydrodesulphurisation	F	0.90
Hydrogen Production	Steam Methane Reforming, Steam Naphtha Reforming, Partial Oxidation Units of Light Feeds Factor for hydrogen production includes energy and emissions for purification (H_2PURE), but capacity is not counted separately	P	300.00
Catalytic Reforming	Continuous Regeneration, Cyclic, Semi-Regenerative, AROMAX	F	4.95
Alkylation	Alkylation with HF Acid, Alkylation with Sulfuric Acid, Polymerisation C3 Olefin Feed, Polymerisation C3/C4 Feed, Dimersol Factor for alkylation/polymerisation includes energy and emissions for acid regeneration (ACID), but capacity is not counted separately	P	7.25
C4 Isomerisation	C4 Isomerisation Factor also includes energy and emissions related to average EU-27 special fractionation (DIB) correlated with C4 isomerisation	R	3.25

C5/C6 Isomerisation	C5/C6 Isomerisation Factor also includes energy and emissions related to average EU-27 special fractionation (DIH) correlated with C5 isomerisation	R	2.85
Oxygenate Production	MTBE Distillation Units, MTBE Extractive Units, ETBE, TAME, Isooctene Production	P	5.60
Propylene Production	Chemical Grade, Polymer grade	F	3.45
Asphalt Manufacture	Asphalt and Bitumen Manufacture Production figure should include Polymer-Modified Asphalt. CWT factor includes blowing	P	2.10
Polymer-Modified Asphalt Blending	Polymer-Modified Asphalt Blending	P	0.55
Sulfur Recovery	Sulfur Recovery Factor for sulfur recovery includes energy and emissions for tail gas recovery (TRU) and H_2S Springer Unit (U32), but capacity is not counted separately	P	18.60
Aromatic Solvent Extraction	ASE: Extraction Distillation, ASE: Liquid/Liquid Extraction, ASE: Liq/Liq w/Extr. Distillation CWT factor cover all feeds including Pygas after hydrotreatment. Pygas hydrotreating should be accounted under naphtha hydrotreatment	F	5.25
Hydrodealkylation	Hydrodealkylation	F	2.45
TDP/TDA	Toluene Disproportionation/Dealkylation	F	1.85
Cyclohexane production	Cyclohexane production	P	3.00
Xylene Isomerisation	Xylene Isomerisation	F	1.85
Paraxylene production	Paraxylene Adsorption, Paraxylene Crystallisation Factor also includes energy and emissions for Xylene Splitter and Orthoxylene Rerun Column	P	6.40
Metaxylene production	Metaxylene production	P	11.10
Phthalic anhydride production	Phthalic anhydride production	P	14.40
Maleic anhydride production	Maleic anhydride production	P	20.80
Ethylbenzene production	Ethylbenzene production Factor also includes energy and emissions for Ethylbenzene distillation	P	1.55
Cumene production	Cumene production	P	5.00
Phenol production	Phenol production	P	1.15

Lube solvent extraction	Lube solvent extraction: Solvent is Furfural, Solvent is NMP, Solvent is Phenol, Solvent is SO_2	F	2.10
Lube solvent dewaxing	Lube solvent dewaxing: Solvent is Chlorocarbon, Solvent is MEK/Toluene, Solvent is MEK/MIBK, Solvent is propane	F	4.55
Catalytic Wax Isomerisation	Catalytic Wax Isomerisation and Dewaxing, Selective Wax Cracking	F	1.60
Lube Hydrocracker	Lube Hydrocracker w/Multi-Fraction Distillation, Lube Hydrocracker w/Vacuum Stripper	F	2.50
Wax Deoiling	Wax Deoiling: Solvent is Chlorocarbon, Solvent is MEK/Toluene, Solvent is MEK/MIBK, Solvent is Propane	P	12.00
Lube/Wax Hydrotreating	Lube H/F w/Vacuum Stripper, Lube H/T w/Multi-Fraction Distillation, Lube H/T w/Vacuum Stripper, Wax H/F w/Vacuum Stripper, Wax H/T w/Multi-Fraction Distillation, Wax H/T w/Vacuum Stripper	F	1.15
Solvent Hydrotreating	Solvent Hydrotreating	F	1.25
Solvent Fractionation	Solvent Fractionation	F	0.90
Mol sieve for C10 + paraffins	Mol sieve for C10 + paraffins	P	1.85
Partial Oxidation of Residual Feeds (POX) for Fuel	POX Syngas for Fuel	SG	8.20
Partial Oxidation of Residual Feeds (POX) for Hydrogen or Methanol	POX Syngas for Hydrogen or Methanol, POX Syngas for Methanol Factor includes energy and emissions for CO Shift and H_2 Purification (U71) but capacity is not counted separately	SG	44.00
Methanol from syngas	Methanol	P	– 36.20
Air Separation	Air Separation	P (MNm^3O_2)	8.80
Fractionation of purchased NGL	Fractionation of purchased NGL	F	1.00
Flue gas treatment	DeSOx and DeNOx	F (MNm^3)	0.10
Treatment and Compression of Fuel Gas for Sales	Treatment and Compression of Fuel Gas for Sales	Elec. Consumption (kW)	0.15
Seawater Desalination	Seawater Desalination	P	1.15
Basis for CWT factors: Net fresh feed (F), Reactor feed (R, includes recycle), Product feed (P), Synthesis gas production for POX units (SG).			

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95114. Hydrogen Production.

***

(a) *Definition of Source Category*. This source category is defined consistent with 40 CFR §98.160(b) and(c). This category is further defined as a hydrogen production source that produces hydrogen whether sold to other entities or consumed on-site.

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(e) *Sampling Frequencies.* When monitoring GHG emissions ~~without a CEMS~~ as specified at 40 CFR §98.164~~3(b)(2)~~, and reporting data as specified at §98.166, the operator must report the following:~~determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below.~~

(1) Carbon and hydrogen content for each feedstock using engineering estimates based on measured data as specified below:

(~~1~~A) ~~When reporting CO_2 emissions f~~For gaseous ~~fuel and~~ feedstock ~~as specified in 40 CFR §98.163(b)(1),~~ the operator must use ~~a~~ weighted average carbon content and hydrogen content from the results of one or more analyses for month n for natural gas or a standardized fuel or feedstock specified in Table 1 of section 95115, or from ~~daily~~ monthly analysis for other gaseous fuels and feedstocks such as refinery fuel gas;

(~~2~~B) ~~When reporting CO_2 emissions f~~For liquid ~~fuel and~~ feedstock ~~as specified in 40 CFR §98.163(b)(2),~~ the operator must use weighted average carbon content and hydrogen content from the results of one or more analyses for month n for a standardized fuel or feedstock specified in Table 1 of section 95115, or from monthly ~~daily~~ sampling ~~for month n~~ for other liquid fuels or feedstocks. ~~Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis~~;

(~~3~~C) ~~When reporting CO_2 emissions f~~For solid ~~fuel and~~ feedstock ~~as specified in 40 CFR §98.163(b)(3),~~ the operator must use weighted average carbon content and hydrogen content from the results of ~~daily~~monthly sampling ~~for month n~~. ~~Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.~~

(2) When monitoring GHG emissions without a CEMS as specified in 40 CFR §98.163(b), the operator must determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below:

(A) When reporting CO_2 emissions for gaseous fuel and feedstock the operator must use a weighted average carbon content from the results of one or more analyses for month n for natural gas or a standardized fuel or feedstock specified in Table 1 of section 95115, or from daily sampling

for month n for other gaseous fuels or feedstocks such as refinery fuel gas.

(B) When reporting CO_2 emissions for liquid fuel and feedstock, the operator must use a weighted average carbon content from the results of one or more analyses for month n for a standardized fuel or feedstock specified in Table 1 of section 95115, or from daily sampling for month n for other liquid fuels or feedstocks. Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis.

(C) When reporting CO_2 emissions for solid fuel and feedstock, the operator must use the weighted average carbon content from the results of monthly sampling for month n for a standardized fuel or feedstock specified in Table 1 of section 95115, or from daily sampling for month n for other solid fuels and feedstock. Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.

***

(g) *Data Reporting Requirements.* When reporting data as specified ~~a~~in 40 CFR §98.166, the operator ~~may~~must also report the ~~amount~~mass of carbon and methane ~~in unconverted feedstock and CO_2~~ for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation (e.g., carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods specified in this regulation). To avoid double-counting, these emissions must ~~such carbon may~~ be subtracted from the total facility emissions.~~carbon in the feedstock~~. ~~For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation, may be separately specified (metric tons of CO_2e/year). The operator must also report the amount of hydrogen produced and sold as a transportation fuel, if known.~~

***

(i) *Transferred CO_2.* The operator must calculate and report the mass of all CO_2 captured, transferred off-site, and reported by the hydrogen production facility as a supplier of CO_2 using reporting provisions found in section 95123. Refineries and ~~H~~hydrogen production facilities ~~should adjust~~ must subtract this reported ~~emissions~~mass ~~for~~of CO_2 that is captured and sold or transferred off-site from their facility emissions report to avoid double counting.

(j) *Additional Product Data.* Operators must report the annual mass of hydrogen gas produced (metric tons) and liquid hydrogen sold~~produced and~~ (metric tons). For hydrogen gas sold, annual masses of on-purpose hydrogen and by-product hydrogen produced must be reported (metric tons). Operators must also specify if the hydrogen plant is an integrated refinery operation.

(k) Methane and nitrous oxide emissions from stationary combustion. Operators must calculate and report fuel high heat value (in units of MMBtu/kg, MMBtu/scf, or MMBtu/gallon for solid, gaseous, or liquid fuels respectively), and CH_4 and N_2O

from fuel stationary combustion sources as set-forth in 40 CFR §98.33(c).

(l) Hydrogen producers shall use the methodology found in section 95113(d) to calculate and report CO_2, CH_4, and N_2O emissions from all flaring at their facility.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95115. Stationary Fuel Combustion Sources.

***

(c) *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 1 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less, subject to the limitation at 40 CFR §98.33(b)(1)(iv), or for biomass-derived fuels listed in Table C-1 of 40 CFR Part 98 when ~~their~~these emissions are not subject to a compliance obligation under the cap-and-trade, except as limited by section 95115(e) ~~regulation and which are not mixed prior to combustion with fuel that has emissions with a compliance obligation~~.

***

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as non-exempt biomass-derived CO_2, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR §98.33. When fuel mass or volume is ~~it~~ measured by lot, the term "n" in Equation C-2b is substituted as the number of lots received in the year.

***

(e) *Procedures for Biomass CO_2 Determination.* Reporting entities must use the following procedures when calculating emissions from biomass-derived fuels that are intermixed with fossil fuels ~~prior to measurement~~:

***

(h) *Aggregation of Units.* Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs

95101(a)(1)(A)-(B) and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or (c)(4), must not aggregate units that belong to different source categories. For the purpose of unit aggregation, units subject to 40 CFR 98 Subpart C that are associated with one source category must not be grouped with other Subpart C units associated with another source category, except when 40 CFR §98.36(c)(2) applies. Aggregation of stationary fuel combustion units is limited to units of the same type, where the unit type categories are: boiler, reciprocating internal combustion engine, turbine, process heater, and other (none of the above). Units subject to section 95112 must use the criteria for aggregation in section 95112(b). Facility operators that choose to aggregate units according to the common stack provision in 40 CFR §98.36(c)(2) may report emissions according to 40 CFR §98.36(c)(2), but they must separately report the ~~heat input (MMBtu)~~fuel use by fuel type as a percentage of the aggregated fuel consumption attributed to~~for~~ each individual unit or each group of units of the same type, such that the grouping of units still meets the limitations for unit aggregation specified elsewhere in this paragraph.

***

(k) *Natural Gas ~~Provider~~ Supplier Information.* The operator who is reporting emissions from the combustion of natural gas must report the ~~provider(s)~~ name(s) of the supplier(s) of natural gas to the facility, the operator's natural gas supplier customer account number(s), natural gas supplier service account identification number(s) or other primary account identifier(s), and the annual MMBtu delivered to each account according to ~~each provider's~~ billing statements (10 therms = 1 MMBtu). In the case that the natural gas is purchased from an entity other than the natural gas supplier, the operator must report the supplier name and customer or service account identification number, but may report the annual MMBtu delivered based on the seller's billing statement.

(l) *Information on Natural Gas Supplied to Downstream Users.* The operator who is reporting emissions from the combustion of natural gas must report whether any of the natural gas reported pursuant to section 95115(k) was supplied to downstream users outside of the operator's facility boundary. If so, the operator must report the name of the facility and the annual MMBtu delivered to each user according to billing statements or financial records.

(m~~l~~) *Procedures for Missing Data*. To substitute for missing data for emissions reported under section 95115 of this article, the operator must follow the requirements of section 95129 ~~beginning with the 2013 emissions data report. For reporting of 2011 emissions in 2012, the operator must use the applicable missing data substitution requirements of 40 CFR Part 98~~.

(n~~m~~) *Additional Product Data.* Operators of the following types of facilities must also report the production quantities indicated below.

***

(5) The operator of a poultry processing facility must report the quantity of whole

chicken and chicken parts, poultry deli products, and protein meal produced in the data year (short tons).

(6) The operatory of a facility that manufactures dehydrated flavors must report the production of dehydrated onion, dehydrated garlic, dehydrated chili peppers, dehydrated parsley, and dehydrated spinach in the data year (short tons).

(7) The operator of a beer brewery must report the production of lager beer in the data year (gallons).

(8) The operator of a snack food manufacturing facility must report the production of fried potato chips, baked potato chips, corn chips, corn curls, and pretzels in the data year (short tons).

(9) The operator of a sugar manufacturing facility must report the production of granulated refined sugar in the data year (short tons)

(10) The operator of a tomato processing facility must report the quantity of aseptic tomato paste, aseptic whole/diced tomato, non-aseptic tomato paste, non-aseptic whole/diced tomato, non-aseptic tomato juice, and canned non-tomato produced in the data year (short tons).

(11) The operator of a pipe foundry must report the production of ductile iron pipe produced in the data year (short tons).

(12) The operator of a facility producing aluminum billets must report the production of aluminum billets and aluminum alloy billets in the data year (short tons).

(13) The operator of a facility mining or processing of rare earth minerals must report the production of rare earth oxide equivalents in the data year (short tons).

(14) The operator of a facility mining or processing diatomaceous earth must report the production of freshwater diatomite filter aids in the data year (short tons).

(15) The operator of a performing forging facility must report the production of seamless rolled rings during the data year (short tons).

(16) The operator of a dairy product facility must report the production of milk, buttermilk, skim milk, cream, butter, sweetened condensed milk, evaporated milk, powdered milk, concentrated milk, cheese, lactose, whey permeate, whey protein concentrate, and deproteinized whey during the data year (short tons).

(17) The operator of an almond or pistachio processing facility must report the sum of pistachios hulled and dried and/or flavored and packaged (short tons) where the hulling and drying, flavoring and packaging is a continuous process, and the sum of almonds pasteurized, blanched and/or flavored and dried (short tons) where flavoring and drying is a continuous process.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	*Default High Heat Value*	*Default CO_2 Emission Factor*
	MMBtu/gallon	*kg CO_2 /MMBtu*
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline (finished)	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

[1] Commercially sold as "propane" including grades such as HD5.

§ 95116. Glass Production.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.145 when estimating missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95117. Lime Manufacturing.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.195 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(2) below.

***

(2) If CaO and MgO content data required by 40 CFR §98.193(b)(2) are missing and a new analysis cannot be undertaken, the operator must apply substitute values according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute for each missing value using the best available estimate of the parameter, based on all available process data for the reporting year.

***

(3) For each missing value of the quantity of lime produced (by lime type) and quantity of lime byproduct/waste produced and sold used to calculate emissions pursuant to 40 CFR §98.193, the operator must~~, when calculating emissions,~~ apply a substitute value according to the procedures in paragraphs (A)-(B) below.

***

(e) *Produced CO_2 Used On-Site.* If a CEMS is not used to measure CO_2 emissions, the facility operator shall report data required by 40 CFR §98.196(b)(17), with the clarification that the referenced annual amount of CO_2 captured for use in the on-site process, reflects CO_2 process emissions generated by the facility that are not released to the atmosphere. The produced CO_2 emissions must be computed as specified in 40 CFR §98.193(b)(2). The method used to determine the amount of CO_2 captured on-site and not emitted must be provided as specified in 40 CFR §98.196(b)(17)(ii), which could include monitoring of system acidity or basicity (pH), analysis of process samples for calcium oxide, or evaluation of the relative

quantities of reactants and products in the lime production and CO_2 reabsorption process (i.e., chemical stoichiometry).

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95118. Nitric Acid Production.

***

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.222(b), the operator must use a method in 40 CFR §98.33(a)(1~~2~~) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

***

(2) For each missing value of nitric acid production used to calculate emissions pursuant to 40 CFR §98.223, the operator must substitute the missing data values according to the procedures in paragraphs (A)-(B) below.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95119. Pulp and Paper Manufacturing

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***

(c) *Procedures for Missing Data.* The operator must comply with 40 CFR §98.275 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(3) below.

***

(d) *Additional Product Data.* In addition to the information required by 40 CFR §98.276, the operator must report the annual production (air dried short tons) of recycled boxboard, recycled linerboard, recycled medium ~~and tissue~~. The operator producing tissue products must report the annual production (air dried short tons) of tissue produced adjusted by water absorbency capacity. ~~For tissue, t~~The operator producing tissue products must also report:

(1) Aa description of the process used to produce tissue, such as through use of an air dryer.

(2) Weighted average water absorption capacity of each tissue product type manufactured using the following equation:

Weighted average water capacity for tissue type =

$$\sum_{i=1}^{n} Oi\,WACi$$

Where:

O_i = annual product output in air dried ton for each tissue product type

WAC_i = water absorption capacity measured for each product type using the methodology specified by ISO 12625-8:2010, except the humidity and temperature conditions shall be 50% relative humidity ±2%, and 23C ±1 C.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95120. Iron and Steel Production.

***

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.175 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided in paragraphs (1)-(2) below.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95121. Suppliers of Transportation Fuels.

***

(a) *GHGs to Report.*

***

(2) Refiners, position holders of fossil fuels and biomass-derived fuels that supply fuel at California terminal racks, and enterers outside the bulk transfer/terminal system of fossil fuels must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2 of this section. However, reporting is not required for fuel in which a final destination outside California or where a use in exclusively aviation or marine applications can be demonstrated. No fuel shall be reported as finished fuel. Fuels must

be reported as the individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2 of this section.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, Liquefied Petroleum Gas, Compressed Natural Gas, and Liquefied Natural Gas.

***

(a) *GHGs to Report.*

***

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies ~~and~~ including intrastate pipelines delivering gas to California end-users must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of the annual volume of natural gas ~~provided~~ delivered to all entities on their distribution systems in California

(3) The California consignee for imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas, compressed natural gas, and liquefied natural gas imported into the state, except for products for which a final destination outside California can be demonstrated

(4) Operators of liquefied natural gas production facilities that receive natural gas supply from interstate pipelines must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of all liquefied natural gas sold or delivered to others, except for product for which a final destination outside California can be demonstrated.

(b) *Calculating GHG Emissions.*

***

(2) For the calculation of CO_{2i} in section 95122(b)(6), ~~L~~local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of natural gas received.

(3) For the calculation of CO_{2I} in section 95122(b)(6), ~~P~~public utility gas corporations and publicly owned natural gas utilities must estimate annual CO_2 emissions from instate receipts of pipeline quality natural gas from other public utility gas corporations, interstate pipelines and intrastate transmission

pipelines, and annual CO_2 emissions from all natural gas redelivered to other public utility gas corporations or interstate pipelines. Annual CO_2 emissions from redelivered natural gas to intrastate pipelines or publicly owned natural gas utilities must be estimated only if emissions from the redelivered natural gas equals or exceeds 25,000 $MTCO_2e$ calculated according to subparagraph (2) above. Emissions are calculated according to Equation NN-3 of 40 CFR §98.403(b)(1) except that CO_{2j} will be the product of $MMBtu_{Total}$ and the default emission factor from Table NN-1 or the product of $MMBtu_{Total}$ and the reporter specific emission factor. $MMBtu_{Total}$ must be calculated as follows:

$$MMBtu_{Total} = MMBtu_{redelivery} - MMBtu_{receipts}$$

Where

$MMBtu_{Total}$ = Total annual MMBtu used in equation NN-3

$MMBtu_{redelivery}$ = Total annual MMBtu of natural gas delivered to other companies as specified above

$MMBtu_{receipts}$ = Total annual MMBtu of natural gas received from other companies as specified above

(4) For the calculation of CO_{2I} in section 95122(b)(6), ~~E~~emissions from receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to Equation NN-5 of 40 CFR §98.403(b)(3) except that CO_{2I} will be calculated as the product of the net annual MMBtu and a default emission factor from Table NN-1 or the product of the net annual MMBtu and a reporter specific emission factor.

(5) Determination of pipeline quality natural gas is based on the annual weighted average HHV, determined according to Equation C-2b of 40 CFR §98.33(a)(2)(ii)(A), for natural gas from a single city gate, storage facility, or connection with an in-state producer, interstate pipeline, intrastate pipeline or local distribution company. If the HHV is outside the range of pipeline quality natural gas, emissions will be calculated using the appropriate subparagraph of section 95122(a) replacing the default emission factor with either a reporter specific emission factor as calculated in 40 CFR §98.404(b)(2) or one determined as follows:

***

(B) For natural gas or biomethane with an annual HHV above 1100 Btu/scf and not exceeding 3% of total emissions estimated under this section, the local distribution company must use the reporter specific weighted yearly average higher heating value and a default emission factor of 54.67 kg CO_2/MMBtu or an emission factor as determined in 40 CFR §98.404(c)(3). If emissions exceed 3% of the total, then the Tier 3 method specified in 40 CFR §98.33(a)(3)(iii) must be used with monthly carbon content samples to calculate the annual emissions from the portion of natural gas that is above 1100 Btu/scf.

(6) When calculating total CO_2 emissions for California, the equation below must be used:

$$CO_2 = \sum CO_{2i} - \sum CO_{2j} - \sum CO_{2l}$$

Where:

CO_2 = Total emissions.

CO_{2i} = Emissions from natural gas received at the state border or city gate, calculated pursuant to section 95122(b)(2).

CO_{2j} = Emissions from natural gas received for redistribution to or received from other natural gas transmission companies, calculated pursuant to section 95122(b)(3).

CO_{2l} = Emissions from storage and direct deliveries from producers calculated pursuant to section 95122(b)(4).

***

(9) The California consignee for imported liquefied petroleum gas must use calculation methodology 2 described in 40 CFR §98.403(a)(2) for calculating CO_2 emissions except that for liquefied petroleum gas table MM-1 of 40 CFR 98 must be used in place of Table NN-2. For liquefied petroleum gas, the consignee must sum the emissions from the individual components of the gas to calculate the total emissions. If the composition is not supplied by the producer, the consignee must use the default value for liquefied petroleum gas presented in Table C-1 of 40 CFR Part 98. The California consignee for compressed natural gas or liquefied natural gas must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of the imported compressed natural gas and liquefied natural gas. ~~received~~ .

(10) The California consignee for imported liquefied petroleum gas, compressed natural gas, or liquefied natural gas must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(11) Operators of liquefied natural gas production facilities described in section 95122(a)(4) must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of the liquefied natural gas sold or delivered in California.

(12) Operators of liquefied natural gas production facilities described in section 95122(a)(4) must estimate and report CH_4 and N_2O emissions based on the MMBtu of liquefied natural gas sold or delivered using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

(~~11~~13) All fuel suppliers in this section must also estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.
GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.
n = Number of greenhouse gases emitted.

***

(d) *Data Reporting Requirements.*

***

(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

***

(D) ~~For each publicly-owned natural gas utility to which a local distribution company~~ In lieu of reporting the information specified in 40 CFR §98.406(b)(6), local distribution companies, including intrastate pipelines that delivers natural gas to downstream gas pipelines and other local distribution companies, ~~the local distribution companies~~ must report the annual volumes in Mscf, annual energy in MMBtu, and the information required in 40 CFR §98.406(b)(12), ~~including EIA number~~. These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

(E) ~~For each customer,~~ In lieu of reporting the information specified in 40 CFR §98.406(b)(7), local distribution companies including intrastate pipelines ~~that report under 40 CFR §98.406 (b)(7)~~ must report the annual volumes in Mscf, annual energy in MMBtu, ~~and~~ customer information required in 40 CFR §98.406(b)(12), and ARB ID number if available for all end-users registering supply equal to or greater than 188,500 MMBtu during the calendar year.

***

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline that delivers natural gas directly to end users, ~~local distribution companies, interstate pipelines or other intrastate pipelines~~ must follow the reporting requirements described under Subpart NN of 40 CFR Part 98 and this section for local distribution companies. In lieu of the city gate information specified by section 95122(b)(2), the intrastate pipeline operator must report the summed volumes (Mscf) and energy (MMBtu) of natural gas delivered to each entity receiving gas from the intrastate pipeline for purposes of estimating the CO_{2i} parameter as specified in section 95122(b)(6).

Additionally, intrastate pipeline operators are ~~not~~ required to estimate a values for CO_{2j} ~~and CO_{2i}~~ as specified in section 95122(b)(3) for natural gas delivered to local distribution companies, interstate pipelines, and other intrastate pipelines. The CO_{2i} parameter as specified in section 95122(b)(4) ~~and (b)(4) and~~ must ~~use~~ have a value of 0 for ~~both when~~ calculating emissions as required by section 95122(b)(6).

(5) In addition to the information required in 40 CFR §98.3(c), the California consignee for liquefied petroleum gas must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b). All California consignees of compressed or liquefied natural gas ~~or natural gas liquids~~ and liquefied natural gas production facilities as described in section 95122(a)(4) must report the annual quantities imported or delivered and sold, respectively, in MMBtu, ~~respectively,~~ and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons separately for compressed natural gas and liquefied natural gas ~~liquids~~ using the calculation methods in section 95122(b).

(6) In addition to the information required in 40 CFR §98.3(c), all local distribution companies that report biomass emissions from biomethane fuel that was purchased by the LDC on behalf of and delivered to end users, and all liquefied natural gas production facilities reporting biomass emission from biomethane, must report, for each contracted delivery, the information specified in section 95103(j)(3).

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95123. Suppliers of Carbon Dioxide.

***

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.425 when substituting for missing data, except ~~for 2013 and later emissions data reports~~ as otherwise provided below.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95124. Lead Production.

The operator of a facility who is required to report under section 95101(a)(1)(B)(8.) of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart R of 40 CFR Part 98 (§§98.180 to 98.188) in reporting stationary combustion and process emissions and related data from lead production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.182(d), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95124(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95118(c)-(d), and section 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If the annual mass or carbon content of carbon-containing inputs are missing when using the process emissions calculation procedure in 40 CFR §98.183(b)(2), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value according to 40 CFR §98.225(a) and the number of days per month.

(B) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute for each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and keep records of the procedures used for estimating missing data pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Product Data.* The operator of a lead production, recycling, recovery, or manufacturing facility must report production of lead and lead alloys, during the data year (short tons).

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Subarticle 3. Additional Requirements for Reported Data

§ 95129. Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

***

(c) *Missing Data Substitution Procedures for Fuel Characteristic Data.* When the applicable emissions estimation methods of this article require periodic collection of fuel characteristic data (including carbon content, high heat value, and molecular weight) the operator must demonstrate every reasonable effort to obtain a fuel characteristic data capture rate of 100 percent for each data year. When fuel characteristic data of a required fuel sample are missing or invalid, the operator must first attempt to either reanalyze the original sample or perform the fuel analysis on a backup sample, or replacement sample from the same collection period as specified in 40 CFR §98.34(a)(2)-(3), to obtain valid fuel characteristic data. If the sample collection period has elapsed and no valid fuel characteristic data can be obtained from a backup or replacement sample, the operator must substitute for the missing data the values obtained according to the procedures in section 95129(c)(1)-(3). The data capture rate for the data year must be calculated as follows for each type of fuel and each fuel characteristic parameter:

Data capture rate = S / T x 100%

Where:

S = Number of fuel samples for which valid fuel characteristic data were obtained according to the applicable sampling requirements (including sampling schedule)

T = Total number of fuel samples required by the applicable sampling requirements

***

(3) If the operator is unable to obtain fuel characteristic data such that less than 80.0 percent of ~~emissions from a source~~a fuel characteristic data element are directly accounted for, the operator must then substitute for each missed data point the greater of the following:

***

(B) The default value in Table 1 of this section (for carbon content) or Table C-1 of 40 CFR Part 98 (for high heat value). If a substitute value is not available in Table 1 of this section or Table C-1 of 40 CFR Part 98, the operator must substitute the highest value recorded for that type of fuel for all records kept pursuant to the requirements of section 95105.

Table 1. Default Carbon Content

Parameter	Missing Data Value
Anthracite Coal	*90%*
Bituminous	*85%*
Subbituminous/Lignite	*75%*
Oil	*90%*
Natural Gas	*75%*
Other Liquid and Gaseous Fuels	*90%*
Other Solid Fuels	*100%*

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

§ 95130. Requirements for Verification of Emissions Data Reports.

***

(a) *Annual Verification.*

(1) Reporting entities required to obtain annual verification services as specified in section 95103(f) are subject to full verification requirements in the first year that verification is required in each compliance period. Upon receiving a positive verification statement, or statements, if applicable, under full verification requirements, the reporting entity may choose to obtain less intensive verification services for the remaining years of the compliance period. Reporting entities subject to this section are also required to obtain full verification services if any of the following apply:

***

(D) A change of ~~ownership~~ operational control of the reporting entity occurred in the previous year.

***

(2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifier(s) for a period of more than six consecutive years, which includes any verifications conducted under this article and for the California Climate Action Registry;~~,~~ The Climate Registry;~~, or~~ Climate Action Reserve; or other verifications conducted in accordance with, or equivalent to, section 95133, including third-party certification of environmental management systems to the ISO 14001 standard or third-party certification of energy management systems to the ISO 50001 standard. This limitation applies only to those verifications that include the scope of activities or operations under the ARB identification number for the emissions data report. The six year period begins on the date the verification body first provides ARB or other verification services to the reporting entity and ends on the date the final verification statement is submitted. The six year period does not reset upon a change in reporting entity ownership or operational control.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95131. Requirements for Verification Services.

Verification services shall be subject to the following requirements.

(a) *Notice of Verification Services.* After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the reporting entity ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, verification services cannot begin until ten working days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95133(f). The notice shall include the following information:

***

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited as a sector specific verifier when required below:

***

(C) For providing verification services to the operator of a facility engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, ~~or~~ nitric acid production, or lead production, at least one verification team member must be accredited by ARB as a process emissions specialist.

***

(b) Verification services shall include, but are not limited to, the following:

***

(8) *Data Checks.* To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions, product data and fuel and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources, fuel and electricity transactions covered under sections 95110 to 95123, 95129, and 95150 to 951578;

(B) The verification team shall use data checks to ensure the accuracy of product data reported under sections 95110 to 95123, and 95150 to 951578 of this article;

***

(D) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reported covered emissions and covered product data are free of material misstatement ~~and the emissions data report otherwise conforms to the requirements of this article~~. At a minimum, data checks must include the following:

***

(F) The verification team is responsible for ensuring via data checks that there is reasonable assurance that the emissions data report conforms to the requirements of this article. In addition, and as applicable, the verifier's review of conformance must confirm the following information is correctly reported:

1. For facilities that combust natural gas, natural gas provider, account identification number, and annual MMBtu of natural gas delivered, reported pursuant to section 95115(k);
2. For suppliers of natural gas, end-user names, account identification numbers, and natural gas deliveries in MMBtu, reported pursuant to section 95122(d)(4);
3. Energy generation and disposition information reported pursuant to section 95112, if any of the following apply:

   A. The facility belongs to an industry sector listed in Table 8-1 of section 95870 of the cap-and-trade regulation;
   B. The facility is applying for legacy contract transition assistance under the cap-and-trade regulation; or
   C. The facility is applying for the limited exemption of emissions from the production of qualified thermal output pursuant to the cap-and-trade regulation.

(~~F~~G) The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must also include a narrative to indicate which sources, product data, and transactions were checked, the types and quantity of data that were evaluated for each source, product data, and transaction, the percentage of reported emissions covered by the data checks, the percentage of product data covered by the data checks, and any separate discrepancies that were identified in emission data or product data.

(9) *Emissions Data Report Modifications.* As a result of data checks by the verification team and prior to completion of a verification statement(s), the

reporting entity must fix all correctable errors that affect ~~make any possible improvements or corrections to~~ covered emissions, non-covered emissions, or covered product data in the submitted emissions data report, and submit a revised emissions data report to ARB. Failure to do so will result in an adverse verification statement. Failure to fix correctable errors that do not affect covered emissions, non-covered emissions, or covered product data represents a non-conformance with this article but does not, absent other errors, result in an adverse verification statement. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.

The verification team shall use professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation or rounding or averaging.

The verification team must document the source of any difference identified, including whether the difference results in a correctable error.

***

(12) *Material Misstatement Assessment.* Assessments of material misstatement are conducted independently on total reported covered emissions and total reported covered product data (units from the applicable sections of this article).

***

(B) When evaluating material misstatement, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(C) The omissions variable described in section 95131(b)(12)(A) does not apply to excluded covered product data as described in section 95103(l), such that excluded covered product data is not considered in the material misstatement assessment.

(13) *Review of Missing Data Substitution.* If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the data year:

***

~~(B) The difference between the reporting entity's calculated emissions and verifier's calculated emissions for that source will be zero when assessing for material misstatement under section 95131(b)(12)(A), when the applicable missing data substitution procedures or interim data collection~~

~~procedure has been correctly applied by the reporting entity; or, any relative accuracy assigned to the emissions estimate under section 95129(h)(4) has been correctly applied.~~

(B~~C~~) If 20 percent or less of any single data elements used to calculate emissions are missing, and emissions are correctly calculated using the missing data requirements in sections 95110 to 95123, 95129, and 95150 to 9515~~7~~8 these emissions will be considered accurate and as meeting the reporting requirements for that source.

(C~~D~~) If greater than 20 percent of any single data element used to calculate emissions are missing or any combination of data elements are missing that would result in more than 5% of a facility's emissions being calculated using missing data requirements in sections 95110 to 95123, 95129, and 95150 to 9515~~7~~8, the verifier ~~will~~ must include a finding of ~~note, at a minimum,~~ a non-conformance with the required emissions calculation methodology as part of the verification statement.

(D~~E~~) The verifier must note the date, time and source of any missing data substitutions discovered during the course of verification in the verification report.

(14) *Review of Product Data.* ~~The verifier must confirm that data substitutions were not used for product data.~~ The verifier's review of product data must include the following, where applicable.

(A) Verifiers must confirm that data substitutions were not used for covered product data.

(B) For product data reported by operators of petroleum refineries subject to section 95113:

1. Verifiers must evaluate conformance and material misstatement for 2013 primary refinery products data reported in 2014, and 2014 data reported in 2015. Beginning with 2015 primary refinery product data reported in 2016, verifiers will evaluate for conformance, and will not assess material misstatement.
2. Verifiers must evaluate conformance for Solomon Energy Intensity Index (EII), if applicable, for all data years.
3. Verifiers must separately evaluate conformance and separately assess material misstatement for the total facility CO_2 weighted tonne and complexity weighted barrel beginning with 2013 data reported in 2014
4. Verifiers must submit multiple product data verification statements for 2013 and 2014 data reports:

A. A verification statement that includes the evaluation of primary refinery products and the Solomon EII, as applicable, as well as non-covered product data;

B. A verification statement for the evaluation of CO_2

weighted tonne;

C. A verification statement for the evaluation of complexity weighted barrel.

5. Beginning with 2015 data reported in 2016, only verification statements for the CO_2 weighted tonne and complexity weighted barrel are submitted. Evaluation of other product data conformance is included in the verification statement for CO_2 weighted tonne.

(c) Completion of verification services must include:

(1) *Verification Statement.* Upon completion of the verification services specified in section 95131(b), the verification body shall complete an emissions data verification statement and ~~a~~ product data verification statement(s), and provide those statements to the reporting entity and ARB by the applicable verification deadline specified in section 95103(f). Before the emissions data verification statement and product data verification statement(s) are completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that reporting entity during that year.

***

(3) *Completion of Findings and Verification Report.* The verification body is required to provide each reporting entity with the following:

(A) A detailed verification report, which shall at a minimum include:

***

The verification report shall be submitted to the reporting entity at the same time as or before the final emissions data verification statement and product data verification statement(s) are submitted to ARB. The detailed verification report shall be made available to ARB upon request.

***

(4) *Adverse Verification Statement and Petition Process.* Prior to the verification body providing an adverse verification statement for emissions or product data, or both, to ARB, the verification body shall notify the reporting entity and the reporting entity shall be provided at least ten working days to modify the emissions data report to correct any material misstatements or nonconformance found by the verification team. The verification body must also provide notice to ARB of the potential for an adverse verification statement(s) at the same time it notifies the reporting entity. The modified report and verification statement(s) must be submitted to ARB before the ~~applicable~~ verification deadline, ~~unless~~seven if the reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(4)(A).

***

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, an error is identified, or an emissions data report that received a positive or qualified positive verification statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days. This paragraph applies to verification statements for emissions and product data. In instances where an error to an emissions data report is identified and determined by ARB to not affect the emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement.

***

(i) *Verifying Biomass-derived Fuels.* In the absence of certification of the biomass-derived fuel by an accredited certifier of biomass-derived fuels, the verification body is subject to the requirements of subarticle 4 of this article as modified below when verifying biomass-derived fuel:

(1) *General biomass-derived fuel verification requirements.* The following requirements apply to the biomass-derived fuel verification:

***

(B) *Verification Services for Biomass-derived Fuels.* When a reporting entity reports that biomass-derived fuels are used, the biomass-derived fuels must be considered when providing all verification services required under section 95131(b) of this article. The verification team must:

1. Review the reporting entity's reported biomass-derived fuel emissions to ensure the biomass-derived fuels are properly listed in the emissions data report as required in section 95103(j) of this article and sections 95852.1.1 and 95852.2 of the cap-and-trade regulation.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

***

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer:

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

***

2. A verification body shall ~~have~~ employ and retain at least five total full-time staff.

***

(C) The applicant shall provide documentation that the proposed verification body maintains a minimum of four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services. Neither general nor umbrella liability policies can be used for the professional liability insurance minimum for the purposes of this provision.

***

(5) Sector Specific and Offset Project Specific Verifiers.

***

(B) *Offset Project Specific Verifier.* The applicant seeking to be accredited as an offset project specific verifier as specified in ~~section 95977.1(b) of~~ the cap-and-trade regulation must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, meet one of the following requirements:

***

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier, and Voluntary Withdrawal from the Accreditation Program.* The Executive Officer may review and, for good cause, including any violation of subarticle 4 of this article or any similar action in an analogous GHG system, modify, suspend, or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not revoke an Executive Order without affording the verification body, lead verifier, or verifier the opportunity for a hearing in accordance with the procedures specified in title 17, California Code of Regulations, section 60055.1 et seq.

***

(4) An accredited verification body or individual verifier may request to voluntarily withdraw its accreditation by providing a written notice to the Executive Officer requesting such withdrawal.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95133. Conflict of Interest Requirements for Verification Bodies.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by ARB to perform verification services for reporting entities. Any individual person or company that is hired by a reporting entity to contract with a verification body on behalf of the reporting entity is also considered in the conflict of interest assessment in this article.

(b) The potential for a conflict of interest must be deemed to be high where:

***

(2) Within the previous five years, any ~~staff member~~ employee of the verification body or any related entity or a subcontractor who is a member of the verification team has provided to the reporting entity any of the following services:

***

(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~~certification~~ or energy management systems such as those conforming to ISO 50001, unless those systems will not be part of the verification process;

***

(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.

***

(c) The potential for a conflict of interest shall be deemed to be low where the following conditions are met:

***

(2) Any ~~non-verification~~ services provided by any member of the verification body or verification team to the reporting entity, within the last five years, are valued at less than 20 percent of the fee for the proposed verification services. Any ~~independent greenhouse gas emissions~~ verification conducted in accordance with, or equivalent to, section 95133 provided by the verification body or verification team outside the jurisdiction of ARB is excluded from this financial assessment but must be disclosed to ARB in accordance with section 95133(e).

(3) Non-ARB verification services are deemed to be low risk if those services are conducted in accordance with, or equivalent to, section 95133, including, but not limited to, third-party certification of environmental management system under ISO 14001 or energy management system under 50001 standards.

***

(g) *Monitoring Conflict of Interest Situations.*

***

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the reporting entity or related entity for which the body has provided verification services, the verification body shall notify the Executive Officer of the contract and the nature of the work to be performed, and revenue received. The Executive Officer, within 30 working days, will determine the level ofe~~r~~ conflict using the criteria in section 95133(a)-(d), if the reporting entity must reverify their emissions data report, and if accreditation revocation is warranted.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Subarticle 5. Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems.

§95150. Definition of the Source Category.

(a) This source category consists of the following industry segments:

***

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a well-pad or associated with a well pad (including compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations (both thermal and non-thermal), and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island. Crude oil and associated gas that is piped to an onshore production facility as an emulsion as defined in section 95102(a) must follow the requirements of section 95156(a)(7)-(10) and meet the metering requirements of section 95103(k) by measuring the emulsion before the first separation tank at the onshore production facility and not at the platform.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95151. Reporting Threshold.

(a) The operator of a facility must report GHG emissions under this subarticle if the facility contains petroleum and natural gas systems and the facility meets the requirements of sections 95101~~(a)~~-(b) and the reporting thresholds outlined in section 95101(e). ~~Facilities with source categories listed in section 95150 must report emissions if their stationary combustion and process emission sources emit 10,000 metric tons of CO_2 equivalent or more per year, or their stationary combustion, process, fugitive and vented emissions equal or exceed 25,000 metric tons of CO_2 equivalent or more per year.~~

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95152. Greenhouse Gases to Report.

***

(c) For an onshore petroleum and natural gas production facility, the operator must report CO_2, CH_4, and N_2O emissions from the following source types on a well-pad, ~~or~~ associated with a well-pad or associated with equipment to which an emulsion is transferred:

***

(6) Crude oil or g~~G~~as well venting during well completions and workovers;

***

(15) Crude oil, ~~and,~~ condensate and produced water CO_2 and CH_4;

~~(16) Produced water CO_2 and CH_4;~~

(17~~6~~) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps); and

(18~~7~~) The operator must use the methods in section 95153(y) and report under this subarticle the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in section 95150. Stationary or portable equipment includes equipment which is integral to the extraction, processing, and movement of oil and/or natural gas; such as well pad construction equipment, well drilling and completion equipment, equipment used for abandoned well plugging and site reclamation, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95153. Calculating GHG Emissions.

***

(c) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 only (not CH_4) vented directly to the

atmosphere or through a flare, engine (e.g. permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using the applicable calculation methodologies described in paragraphs (c)(1)-(c)(10) below.

***

(7) Determine volume fraction of CO_2content in natural gas out of the AGR unit using one of the methods specified in paragraph (c)(7) of this section.

~~1.~~A. If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, the operator may install a continuous gas analyzer.

~~2.~~B. If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in section 95154(b).

~~3.~~C. Use sales line quality specification for CO_2 in natural gas.

***

(f) *Crude oil and g~~G~~as well venting during well completions and well workovers.* Using one of the calculation methodologies in this paragraph (f)(1) through (f)(5) below, operators must calculate CH_4, CO_2 and N_2O (when flared) annual emissions from crude oil and gas well venting during both conventional completions and completions involving hydraulic fracturing in wells and both conventional well workovers and well workovers involving hydraulic fracturing.

(1) *Calculation Methodology 1.* Measure total gas flow with a recording flow meter (analog or digital) installed in the vent line ahead of a flare or vent id used. The facility operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:

$$E_a = V_M - V_{CO2 or N2} - V_{SG} \quad \text{(Eq. 8)}$$

Where:

E_a = Natural gas emissions during the well completion or workover at actual conditions (m^3).

V_M= Volume of vented gas measured during well completion or workover (m^3).

$V_{CO2 or N2}$ = Volume of CO_2 or N_2 injected during well completion or workover (m^3).

V_{SG} = Volume of natural gas recovered into a sales pipeline (m^3).

(A) All gas volumes must be corrected to standard temperature and pressure using methods in section(r).

(B) Calculate CO_2 and CH_4 volumetric and mass emissions using the methodologies in sections (s) and (t).

***

(h) ~~Dump Valves~~*Onshore production and storage tanks.* Calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using the method found in 95153(i).

***

(j) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

***

(3) Estimate venting emissions using Equation 15 or Equation 16 of this section.

$$E_{a,n} = GOR * FR * D \quad \text{(Eq. 15)}$$

$$E_{a,n} = PR * D \quad \text{(Eq. 16)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio, for well p in -basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the year the well(s) is tested.

***

(m) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor with a rated horsepower of 250hp or greater covered by sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3) the operator must conduct an annual measurement in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement:

***

(C) Not operating depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

***

~~(D)~~2. An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT_m variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

***

(3) For blowdown valve leakage and isolation valve leakage to open ended vents, use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in sections 95154(c) and 95154(d), respectively. For through valve leakage, such as isolation valves, the facility operator may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

***

(o) *Leak detection and leaker emission factors.* The operator must use the methods described in section 95154(a) to conduct leak detection(s) of equipment leaks from all components types listed in sections 95152(c)(16~~7~~), (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1). This paragraph (o) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (o) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (o), calculate equipment leak emissions per component type per reporting facility using Equations 25 or 26 of this section for each component type. Use Equation 25 for industry segments listed in section 95150(a)(1) – (a)(7). Use Equation 26 for natural gas distribution facilities as defined in section 95150(a)(8).

$$E_{s,i} = GHG_i * \sum_{p=1}^{x}(EF * T_p) \quad \text{(Eq. 25)}$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^{t}\sum_{p=1}^{x}(EF * T_{p,q}) \quad \text{(Eq. 26)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (o)(1) through (o)(8) of this section.

X = Total number of each component type.

EF = Leaker emission factor for specific component types listed in Table 1A and 2 through 7 of Appendix A.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4.

T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.
t = Calendar year of reporting.
n = The number of years over which one complete cycle of leak detection is conducted over all the Transmission – Distribution (T-D) transfer stations in a natural gas distribution facility; $0 < n \leq 5$. For the first (n-1) calendar years of reporting the summation in Equation 26 should be for years that the data is available.
$T_{p,q}$ = The total time the component, p, was found leaking and operational, in hours, in year q. If one leak detection survey is conducted, assume the component was leaking for the entire period n. If multiple leak detection surveys are conducted, assume the component found to be leaking has been leaking since the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

***

(8) Natural gas distribution facilities for above ground transmission-distribution transfer stations, shall use the appropriate default leak emission factors listed in Table 7 of Appendix A for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(A) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility operator chooses to use the multiple year option then the number of T-D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(p) *Population count and emission factors.* This paragraph applies to emissions sources listed in sections 95152(c)(1~~7~~6), (f)(~~5~~7), (g)(3), (h)(3), (i)(2), (i)(3), (i)(4), ~~(i)(5),~~ and (i)(6) on streams with gas content greater than 10 percent CH_4 plus CO_2

by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (p) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation 27 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \quad \text{(Eq. 27)}$$

***

(6) Natural gas distribution facilities must use the appropriate emission factors as described in paragraph (p)(6) of this section.

***

(B) Emissions from all above grade metering-regulating stations (including above grade T-D transfer stations) must be calculated by applying the emission factor calculated in Equation 28 and the total count of metering/regulator runs at all above grade metering-regulating stations (inclusive of T-D transfer stations) to Equation 27. The facility wide emission factor in Equation 28 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation 26 and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per (p)(1) of this section. A meter on a regulator run is considered one meter regulator run. Facility operators that do not have above grade T-D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with section 95157(c)(16)(T).

$$EF = E_{s,i}/(8760 * Count) \quad \text{(Eq. 28)}$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade meter/regulator run for GHG_i in cubic feet per meter/regulator run per hour.

$E_{s,i}$ = Annual volumetric GHG_i emissions, CO_2 or CH_4, at standard condition from each component type at all above grade T-D transfer stations, from Equation 2~~7~~6.

Count = Total number of meter/regulator runs at all T-D transfer stations that were monitored over the years that constitute one complete cycle as per paragraph (~~p~~o)(8)(~~i~~A) of this section.

8760 = Conversion to hourly emissions.

***

(u) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions from EOR operations using critical CO_2 injection as follows:

$$Mass_{CO2} = N * V_v * R_c * GHG_i * 10^{-3} \quad \text{(Eq. 33)}$$

Where:

$Mass_{CO2}$ = Annual EOR injection gas venting emissions in metric tons from blowdowns.
N = Number of blowdowns for the equipment in the calendar year.
R_c = Density of critical phase EOR injection gas in kg/ft^3. The facility operator may use an appropriate standard method published by published by a consensus based organization if such a method exists or the facility operator may use an industry standard practice to determine density of super-critical emissions.
V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.
GHG_i = Mass fraction of GHG_i in critical phase injection gas.
1x 10^{-3} = Conversion factor from kilograms to metric tons.

(v) *Crude Oil, Condensate, and Produced Water Dissolved CO_2 and CH_4.* The operator must calculate dissolved CO_2 and CH_4 in crude oil, condensate, and produced water. Emissions must be reported for crude oil, condensate, and produced water sent to storage tanks, ponds, and holding facilities. The facility operator must also report the volume of produced water in barrels per year.

(1) Calculate CO_2 and CH_4 emissions from crude oil, condensate, and produced water using Equation 33A:

$$E_{CO2/CH4} = (S * V)\left(1 - (VR * CE)\right) \quad \text{(Eq. 33A)}$$

Where:

$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.
S = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of crude oil, condensate, and produced water (as determined in paragraph (v)(1)(A)1. or mass of CO_2 or CH_4 recovered in a vapor recovery system per barrel of crude oil, condensate, or produced water (as determined in paragraph (v)(1)(A)2.
V = Barrels of crude oil, condensate, or produced water sent to tanks, ponds, or holding facilities annually.
VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).
CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(A) S (the mass of CO_2 or CH_4 per barrel of crude oil, condensate, or produced water) shall be determined using one of the following methods:

1. Flash liberation test. Measure the amount of CO_2 and CH_4 liberated from crude oil, condensate, or produced water when the crude oil, condensate, or produced water changes temperature and pressure

from well stream to standard atmospheric conditions, using a sampling methodology and ~~a~~ ARB's flash liberation test ~~such as~~ procedure entitled "Flash Emissions of Greenhouse Gases and Other Compounds from Crude Oil and Natural Gas Separator and Tank Systems," which is included as Appendix B of this article. ~~adopted Gas Processor Association, American Society for Testing and Materials, or U.S. EPA standards.~~ The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of crude oil, condensate, or produced water. The test results from the flash liberation test must be submitted to ARB as part of the emissions data report.

2. Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from crude oil, condensate, or produced water as follows:

***

e. The vapor recovery system method is included in Appendix B).

(B) Emissions resulting from the destruction of the vapor recovery system gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.

***

(y) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (y)(3) and (y)(4) of this section as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C of 40 CFR Part 98, or is a blend ~~containing~~ completely consisting of one or more fuels listed in Table C-1, calculate emissions according to paragraph (y)(1)(A). If the fuel combusted is natural gas and is of pipeline quality specification, use the calculation methodology described in paragraph (y)(1)(A) and the facility operator may use the emission factor provided for natural gas as listed in Subpart C, Table C-1. If the fuel is natural gas, and is not pipeline quality calculate emissions according to paragraph (y)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (y)(2).

(A) For fuels listed in Table C-1 or a blend ~~containing~~ completely consisting of one or more fuels listed in Table C-1 of Subpart C, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in section 95115.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality, calculate combustion emissions as specified below ~~follows~~:

(A) The operator may use company records, which includes the common pipe method, to determine the volume of fuel combusted in the unit during the reporting year.

***

(C) Calculate GHG volumetric emissions at actual conditions using Equations 35 and 36 of this section:

$$E_{a,CO2} = \sum_{n=1}^{12}\left[(V_a * Y_{CO2}) + \eta \sum_{j=1}^{5} V_a * Y_j * R_j\right] \quad \text{(Eq. 35)}$$

$$E_{a,CH4} = \sum_{n=1}^{12}[V_a * (1-\eta) * Y_{CH4}] \quad \text{(Eq. 36)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
V_a = Volume of fuel gas sent to combustion unit in cubic feet, during the year.
Y_{CO2} = Concentration of CO_2 constituent in gas sent to combustion unit.
$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.
η = Fraction of gas combusted for portable and stationary equipment determined using an engineering estimation. For internal combustion devices, a default of 0.995 can be used.
Y_j = Concentration of gas hydrocarbon constituent j (such as methane, ethane, propane, butane and pentanes plus) in gas sent to combustion unit.
R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.
Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.
n = Month of the year

Calculate CO_2 and CH_4, volumetric emissions at standard conditions using the provisions of section 95153(r). Use the provisions in sections 95153(s) and (t) to covert volumetric gas emissions to GHG volumetric and GHG mass emissions respectively.

(D) Calculate N_2O mass emissions using Equation 37 of this section.

$$Mass_{N2O} = (1 \times 10^{-3}) * Fuel * HHV * EF \quad \text{(Eq. 37)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons N_2O).
Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV = For the higher heating value for field gas or process vent gas, use either a weighted average of quarterly measurements of HHV or a default value of 1.235×10^{-3} ~~mm~~MMBtu/scf for HHV.
EF = Use 1.0×10^{-4} kg N_2O/~~mm~~MMBtu.
1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 ~~mm~~MMBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 ~~mm~~MMBtu/hr (or equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each internal fuel combustion unit.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95154. Monitoring and QA/QC Requirements.

***

(a) Facility operators must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in sections 95153(i), (m), (n) and (o) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR Part 60, subarticle A, §60.18 of the *Alternative work practice for monitoring equipment leaks*, §60.18(i)(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subarticle A, Table 1: *Detection Sensitivity Levels*; §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records (July 1, 2011, which is hereby incorporated by reference). Any emissions detected by the optical gas ~~imagining~~ imaging instrument is a leak unless screened with Method 21 (40 CFR Part 60, appendix A-7 (July 1, 2011), which is hereby incorporated by reference) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, facility operators must operate the optical gas ~~imagining~~ imaging instrument to image the source types required by this subarticle in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas ~~imagining~~ imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than two meters above a support surface.

***

~~(f) *Special reporting provisions: best available monitoring methods.* Best available monitoring methods will be allowed for the reporting of 2012 data as described in paragraphs (1)-(4). Beginning with collection of data on January 1, 2013, best available monitoring methods will no longer be allowed.~~

~~(1) ARB will allow owners or operators to use best available monitoring methods for certain parameters in section 95153 as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:~~

~~(A) Monitoring methods currently used by the facility that do not meet the specifications of this subarticle.~~
~~(B) Supplier data.~~
~~(C) Engineering estimation.~~
~~(D) Other company records.~~

~~(2) Operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subarticle, and only where required measurements cannot be duplicated due to technical limitations after December 31, 2012. These well-related sources are:~~

~~(A) Gas well venting during well completions and workovers as specified in section 95153(f).~~
~~(B) Well testing venting and flaring as specified in section 95153(e).~~

~~(3) Operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subarticle, specifically for events that generate data that can be collected in 2012 and cannot be duplicated after December 31, 2012. These sources are:~~

~~(A) Cumulative hours of venting, days, or times of operation in sections 95153 (d), (e), (f), (j), (m), (n), (o), and (p).~~
~~(B) Number of blowdowns, completions, workovers, or other events in sections 95153(e), (f), (g), and (u).~~
~~(C) Cumulative volume produced, volume input or output, or volume of fuel used in sections 95153(c), (d), (h), (i), (j), (k), (l), and (y).~~

~~(4) Operators may use best available monitoring methods for sources requiring leak detection and/or measurement. These sources include:~~

~~(A) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152 (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4).~~
~~(B) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152(d)(5), (e)(6), (f)(5), (g)(3), and (h)(3).~~
~~(C) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in sections 95152(c)(3) and (d)(4).~~
~~(D) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in sections 95152(c)(17) (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1).~~

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95155. Procedures for Estimating Missing Data.

(a) A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the operator must repeat the estimation or measurement activity for those sources within the measurement period. In cases where repeat sampling and/or analysis cannot be completed, the operator must follow the missing data substitution procedures outlined below:~~for 2013 and later emissions data reports.~~

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95156. Additional Data Reporting Requirements.

Operators must conform with the data reporting requirements in section 95157 except as specified below.

(a) In addition to the data required by section 95157, the operator of an onshore and offshore petroleum and natural gas production facility must report the following data disaggregated within the basin by each facility that lies within contiguous property boundaries:

***

(7) Barrels of crude oil produced using thermal enhanced oil recovery. This includes the crude oil fraction piped as an emulsion as defined in section 95102(a);

(8) Barrels of crude oil produced using methods ~~other than~~ non-thermal enhanced oil recovery. This includes the crude oil fraction piped as an emulsion as defined in section 95102(a);

(9) MMBtu of associated gas produced using thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a);

(10) MMBtu of associated gas produced using methods ~~other than~~ non-thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a).

~~(11) The operator of an onshore petroleum and natural gas production facility may voluntarily report the annual product data information in sections 95156(a)(9)-(10) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB~~

~~by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual product data listed in section 95156(a)(9)-(10).~~

(b) For dry gas production, the operator of an onshore petroleum and natural gas production facility must~~may voluntarily~~ report its annual volume of dry gas produced (~~Mscf~~MMBtu) ~~for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 dry gas produced, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the volume of dry natural gas produced (Mscf).~~

~~(c) For underground natural gas storage, the operator must report the volume of natural gas extracted (Mscf).~~

(c~~d~~) The operator of a natural gas liquid fractionating facility, ~~or~~ a natural gas processing facility, or an onshore petroleum and natural gas production facility with a gas plant that produces less than 25 MMscf per day must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

***

~~(e) The operator of a natural gas liquid fractionating facility or a natural gas process facility may voluntarily report the annual product data information in sections 95156(d)(1)-(12) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual product data listed in section 95156(d)(1)-(12).~~

(d) Onshore natural gas processing facilities that have an annual average throughput of 25 MMscf per day or greater must also report the volume of associated gas, waste gas, and natural gas processed (MMBtu).

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§95157. Activity Data Reporting Requirements.

***

(c) Report the information listed in this paragraph for each applicable source type in metric tons for each GHG type. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas

to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring of the gas. Both the vented and flared emissions will be reported under respective source types and not under flare source type.

***

(6) For well completions and workovers, report the following for each basin category:

(A) Total count of gas well and oil well completions in calendar year.
(B) Total count of gas well and oil well workovers in calendar year.

***

(9) For transmission tank emissions identified using optical gas ~~imagining~~ imaging instrument pursuant to section 95154(a) (refer to section 95153(i)), or acoustic leak detection of scrubber dump valves, report the following:

***

(18) For EOR hydrocarbon liquids dissolved CO_2 (refer to section 95153(v)), report the following:

(A) Volume of crude oil produced in barrels per year.
~~(B) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.~~
(~~C~~B) Report annual CO_2 and CH_4 emissions at the basin level.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

***

(H) Annual volume of associated gas produced (Mscf) using thermal enhanced oil recovery and non-thermal enhanced oil recovery.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

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APPENDIX A TO THE STAFF REPORT

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Appendix B
to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

TEST PROCEDURE

Flash Emissions of Greenhouse Gases and
Other Compounds from Crude Oil and Natural Gas
Separator and Tank Systems

Test Procedure

Flash Emissions of Greenhouse Gases and Other Compounds from Crude Oil and Natural Gas Separator and Tank Systems

1. PURPOSE AND APPLICABILITY

This procedure is used to determine annual emission rates of Greenhouse Gases and other compounds from crude oil and natural gas separator and tank systems. This procedure is conducted by gathering one sample of crude oil or condensate and one sample of produced water from a pressurized vessel and having the liquids analyzed by a laboratory to determine the composition and volume of gas released from the liquids while they change from reservoir to standard atmospheric conditions. The laboratory results are used in conjunction with throughput to calculate the emission rates per year. The sampling and lab analyses may also be conducted to evaluate emissions from Flowback Fluids used to stimulate or hydraulically fracture a crude oil or natural gas well if they are handled by a separation and tank system. An alternative methodology is included for determining the specified emissions rates using measured vapor recovery system parameters provided the system meets the requirements specified in Section 9.

2. PRINCIPLE AND SUMMARY OF TEST PROCEDURE

The sampling and laboratory methods specified in this procedure are used to take samples of liquids and conduct a Flash Analysis on crude oil or natural gas separator and tank systems and are based on American Standards and Testing Materials (ASTM), US Environmental Protection Agency (EPA), and Gas Processor Association (GPA) methods and standards. The alternative vapor recovery system methodology described in Sections 9 and 10.2 is based on common industry practices.

Samples must be taken from a primary vessel located in a separator and tank system using the sampling methods specified in this procedure. Non-pressurized tanks or secondary vessels may not be used for sampling. Typical sampling points are from pressurized Two-Phase or Three-Phase Separators or vessels used to measure Percent Water Cut (e.g., Automatic Well Tester). The liquids found in these vessels contain gases that will flash from the liquids as vapor when the liquids flow into lower pressure secondary vessels. This procedure is used to measure both the volume and composition of this flashed gas vapor. Liquid samples of a crude oil-produced water emulsion do not contain enough crude oil to be evaluated by a laboratory and are not applicable to this procedure.

Two sampling methods are specified: The first is a displacement method used for gathering crude oil or condensate. The second is for gathering produced water. Both methods are specified due to the nature of the laboratory analyses and the design of the sampling cylinders. Produced water cannot be displaced

from a Double-Valve Cylinder using laboratory grade water and heavy crude oil may solidify and cause problems with a Floating-Piston Cylinder.

The laboratory methods are used to measure the composition and volume of gas that flash from liquids while they cool or depressurize to standard atmospheric conditions. This includes the molecular weight and weight percent of the gaseous compounds and a Gas to Oil Ratio or Gas to Water Ratio. The laboratory results are applied to the annual liquid production rates to calculate Greenhouse Gas and other compound emission rates per year.

3. DEFINITIONS

For the purposes of this procedure, all definitions are found in section 95102(a) of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.).

4. BIASES AND INTERFERENCES

4.1 The sampling methods specified in this procedure have an impact on the laboratory methods and the final results reported. All samples must be gathered in adherence with the minimum procedures and specifications identified in this procedure.

4.2 A representative sampling point must be selected to ensure that pressurized gases remain suspended in liquid during sampling. Obtaining samples from a non-pressurized vessel or a vessel connected to a vapor recovery system will produce non-representative results.

4.3 All pressure and temperature measurements must be acquired using calibrated instruments as described in Section 5. Un-calibrated equipment, including pressure or temperature gauges installed on vessels, may produce non-representative results. This may result in data errors when analyzing samples in a laboratory.

4.4 The analytical portion of this procedure must be conducted by laboratories experienced with laboratory instrumentation, analytical methods, and the laboratory methods specified in this procedure.

5. EQUIPMENT SPECIFICATIONS

5.1 A pressure gauge capable of measuring liquid pressure less than 200 pounds per square inch pressure within +/-10% accuracy.

5.2 A pressure gauge capable of measuring liquid pressure greater than 200 pounds per square inch pressure within +/- 5% accuracy.

5.3 A temperature gauge capable of reading liquid temperature to within +/- 2°F. The range of the gauge must be at least 32 to 200°F.

5.4 A volume meter with a minimum of +/- 5% accuracy over the entire range of flow rates for which the meter is used. Volume meters must be calibrated annually against a NIST traceable standard.

6. TEST EQUIPMENT

6.1 A Double-Valve Cylinder filled with laboratory grade water for crude oil or condensate or a Floating-Piston Cylinder for produced water.

6.2 A Graduated Cylinder to measure displaced laboratory grade water from a Double-Valve Cylinder.

6.3 A waste container suitable for capturing and disposing sample liquid.

6.4 High-pressure rated components and control valves that can withstand pressure under the same operating conditions as the vessel sampled.

6.5 A low-pressure and a high-pressure measuring device with minimum specifications listed in Section 5.

6.6 A temperature measuring device with minimum specifications listed in Section 5.

6.7 A calibrated volume meter with temperature and pressure gauges each with minimum specifications listed in Section 5 for measuring collected vapor recovery gas volume as described in Section 9.

6.8 A stainless steel hand pump equipped with one-way check valves suitable for pumping low API gravity crude oil into a Double-Valve Cylinder per Section 7.3. Stainless steel is required to prevent sample contamination.

7. SAMPLING METHODS

Pre-Sampling Requirements

Prior to gathering liquid samples, the sampling technician must be provided with the vessel description, Throughput, Percent Water Cut, Days of Operation, and a description of the vapor recovery system on downstream vessels by the facility operator as indicated in Table 1 and on Form 1. If required, the Percent Water Cut may be measured using ASTM D-4007. For sampling liquids that may contain proprietary compounds, such as those used in hydraulic fracturing liquids, a Tentatively Identified Compound List must also be provided prior to gathering liquid samples. All of this information specified is required to calculate and report the results of this test procedure. The results of this test procedure may be nullified without the specified information.

Background

The sampling method used for this procedure depends on the type of liquid to be sampled. Crude oil or condensate is collected using the Crude Oil or

Condensate Sampling Method specified in Section 7.1. Produced water is collected using the Produced Water Sampling Method specified in Section 7.2. Low API gravity crude oil that will not flow into a sampling cylinder may be collected using the method specified in Section 7.3.

Liquid samples must only be taken from separated liquids. This is accomplished by taking samples from different levels in a pressurized separator, which may be a permanent or temporarily installed vessel. Liquid samples of emulsions cannot be evaluated by a laboratory and are therefore not applicable to this procedure. To gather a liquid sample, the sample vessel must be pressurized. Samples must not be taken from tanks or separators open to atmosphere.

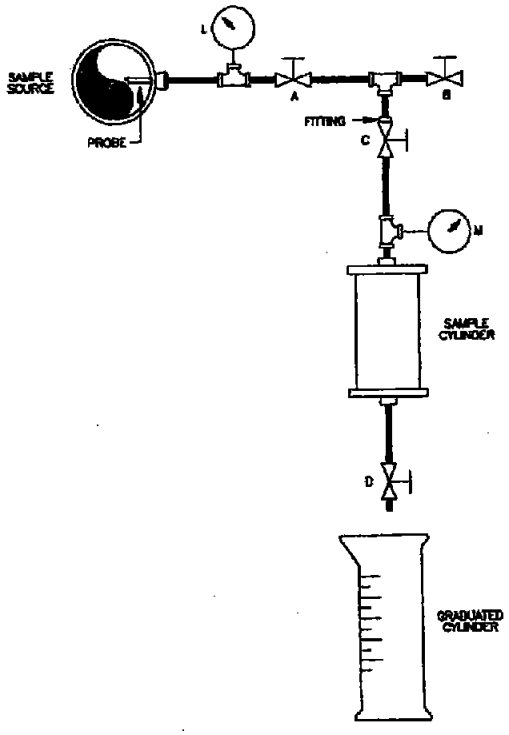
When a liquid sample is gathered, the technician measures the pressure and temperature of the liquid using the calibrated gauges specified and records the vessel and liquid characteristics as reported by the facility operator. The cylinder is then identified with a Cylinder Identification Tag (See Section 8) and sent to a laboratory for analysis. The laboratory heats and pressurizes the liquid to the same conditions recorded at the time of sampling and performs a Flash Analysis which measures the rate and composition of gas evolved from the liquid while it cools and depressurizes to specified atmospheric conditions.

7.1 CRUDE OIL OR CONDENSATE SAMPLING METHOD

The Crude Oil or Condensate Sampling Method is conducted by displacing laboratory grade water with pH between 5 and 7 from a Double-Valve Sampling Cylinder. Figure 1 illustrates a Double-Valve Cylinder sampling train. The configuration shows a cylinder outfitted with high-pressure rated components that can be used for controlling the flow of liquid. Calibrated temperature (Gauge L) and pressure (Gauge M) gauges are included for conducting field measurements. Sample liquid enters the cylinder when water is displaced into a graduated cylinder. The amount of sample liquid contained in the cylinder is equal to the amount of laboratory grade water measured in the graduated cylinder.

Figure 1

Double-Valve Cylinder Sampling Train



(a) If samples are to be shipped to a laboratory, calculate 90% of the cylinder volume, which will be the volume of sample to gather. As an example, 90% of a 500ml cylinder is 0.9 x 500 ml = 450 ml. This also represents the amount of water to displace with sample liquid. The cylinder must retain 10% of the laboratory grade water to allow for flashing during shipping and to prevent an explosive situation from occurring. If samples are not going to be shipped to a laboratory, this step does not need to be performed. Instead, fill the entire cylinder with sample liquid after purging with three cylinder volumes of liquid as described in (f).

(b) Connect the sampling train to a sampling point on the pressurized vessel. Bushings or reducers may be required.

(c) Purge the sample line: with Valves C and D closed, route the outlet of Valve B into a suitable waste container to purge sample liquid. Slowly open Valve B. Slowly open Valve A and allow air and liquid to purge. Continue purging until a consistent, steady stream of liquid is observed and gas pockets subside. Close Valve B.

(d) With Valve C and D closed, slowly open Valve A to the full-open position and then slowly open Valve C to the full-open position.

(e) Slowly open Valve D to allow a slow discharge of water into the graduated cylinder at a rate of approximately 60 milliliters per minute (1 drip per second).

(f) Record the temperature from Gauge L and pressure from Gauge M while the liquid is filling the cylinder. Do not take temperature or pressure measurements on stagnant liquid. If the sample is to be shipped as described in (a), continue displacing the laboratory grade water from the cylinder until 90% of the water is displaced. If the cylinder is not going to be shipped, continue filling the cylinder with sample liquid until three cylinder volumes of liquid have passed through the sampling cylinder.

(g) Close Valves D, C, and A in that order.

(h) Purge the line pressure: slowly open Valve B and allow pressurized liquid to drain into the waste container.

(i) Disconnect the Double-Valve Cylinder from the sampling train and disconnect the sampling train from the pressurized vessel.

(j) Check Valves C and D for leaks. If either Valve C or D is leaking, drain the cylinder into a suitable waste container and use a different cylinder to obtain a new sample.

(k) Wrap the threaded connections of the cylinder with Teflon tape and cap using threaded metal caps to protect the threads and ensure the cylinder is securely sealed for shipping.

(l) Identify the sample cylinder as specified in Section 8.

7.2 PRODUCED WATER SAMPLING METHOD

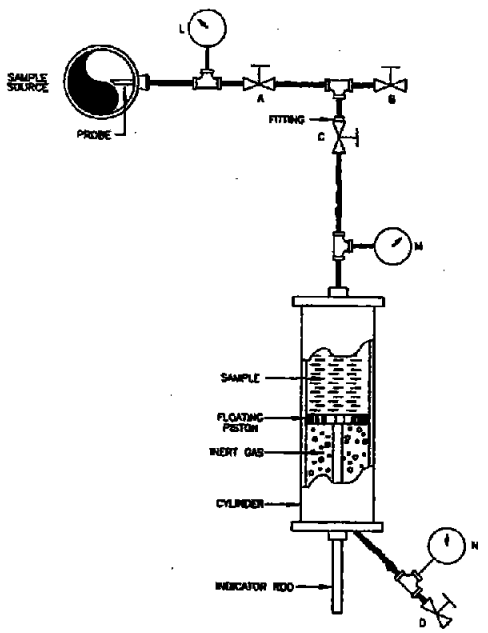
The Produced Water Sampling Method is conducted using a Floating-Piston Cylinder. This allows the sample liquid to be extracted from the cylinder without using laboratory water. The cylinder is provided by a laboratory with the piston pressurized with inert gas to approximately 1,000 psig or greater. Note: produced water may be gathered using a Double-Valve Cylinder as described in Section 7.1 provided that the laboratory can displace the produced water from the cylinder without commingling the sample liquid with laboratory grade water.

Prior to gathering a sample, the technician first measures the vessel pressure and temperature using the calibrated gauges specified. The technician then bleeds off excess pressure from the piston to at least 10 psig greater than the vessel to be sampled. Sample liquid is gathered by slowly bleeding off additional pressure from the piston. The rate at which liquid is gathered must not exceed 60 milliliters per minute in order to prevent the liquid from flashing gases within the sample cylinder.

Figure 2 shows a Floating-Piston Cylinder sample train outfitted with high-pressure rated components. Calibrated temperature (Gauge L) and pressure (Gauge M and N) gauges are included for conducting the required vessel measurements.

Figure 2

Floating-Piston Cylinder Sampling Train



(a) Connect the sampling train to a sampling point on the pressurized vessel. Bushings or reducers may be required.

(b) Purge the sample line: with Valves C and D closed, route the outlet of Valve B into a suitable waste container to purge sample liquid. Slowly open Valve A to the full-open position. Slowly open Valve B and allow liquid to purge. Continue purging until a consistent, steady stream of liquid is observed and gas pockets subside. Close Valve B.

(c) Slowly open Valve C to the full-open position.

(d) Slowly open Valve D to release inert gas pressure until the pressure indicated on Gauge N is equal to Gauge M. When both gauges read equal pressure, close Valve D and prepare to gather sample liquid.

(e) Slowly open Valve D and allow liquid to enter the cylinder at a slow rate of approximately 60 ml per minute to prevent liquid from flashing within the sampling cylinder. Use the measurement scale located on the sampling cylinder and a stopwatch to measure the rate at which liquid is gathered.

(f) Record the temperature from Gauge L and pressure from Gauge M while liquid is gathered. Do not take measurements on stagnant liquid.

(g) Continue gathering liquid until the cylinder is 80% full as indicated on the cylinder scale. The rate at which liquid enters the cylinder, and the

volume of liquid in the cylinder, are indicated on the sample cylinder. No outage is required when using a Floating-Piston Cylinder.

(h) Close valves D, C, and A in that order.

(i) Purge the line pressure: slowly open Valve B and allow pressurized liquid to drain into the waste container.

(j) Disconnect the Floating-Piston Cylinder from the sampling train and disconnect the sampling train from the pressurized vessel.

(k) Check Valves C and D for leaks. If either Valve C or D is leaking, drain the cylinder into a suitable waste container and use a different cylinder to obtain a new sample.

(l) Wrap the threaded connections of the cylinder with Teflon tape and cap using threaded metal caps to protect the threads and ensure the cylinder is securely sealed for shipping.

(m) Identify the sample cylinder as specified in Section 8.

7.3 LOW API GRAVITY CRUDE OIL SAMPLING METHOD

In some cases, low API gravity crude oil may not flow into a sampling cylinder. This could be due to the viscosity, temperature, or pressure of the oil. In these cases, a stainless steel hand pump is used to assist with the collection of liquid. The pump must be outfitted with one-way check valves to ensure that liquid flows in only one direction. The difference between the Displacement Method and this method is that the hand pump is used in place of system pressure.

(a) Install the stainless steel hand pump equipped with one-way check valves as described in Section 6 at the inlet of the Double-Valve Cylinder Sampling Train.

(b) Using the hand pump to slowly force the flow of liquid, collect a liquid sample following the sample procedures described in Section 7.1.

8. CYLINDER IDENTIFICATION TAG

8.1 Identify the cylinder with a Cylinder Identification Tag. Both the tag and a copy of Form 1 must be completed prior to sampling using information provided by the facility operator and must include the following minimum information:

(a) Date and time;

(b) Unique sample ID number or cylinder number;

(c) Sample type (crude oil, condensate, or produced water);

(d) Sample pressure and temperature during sampling;

(e) Vessel description;

(f) Vessel throughput of emulsion or liquid in barrels per day;

(g) Percent Water Cut;

(h) Days of Operation per Year;

(i) Facility name and location of where sample was gathered; and,

(j) Attach a completed copy of Form 1.

8.2 Package the cylinder with the information tag and a copy of Form 1.

9. ALTERNATIVE METHODOLOGY FOR CALCULATING EMISSION RATES USING MEASURED VAPOR RECOVERY SYSTEM PARAMETERS IN LIEU OF GATHERING AND EVALUATING LIQUID SAMPLES

This methodology is used to measure the specified emission rates using a vapor recovery system in lieu of gathering and evaluating liquid samples. This methodology requires that all gases flashed from liquid are collected and measured, and that a vapor recovery system is installed on a minimum of the primary and secondary vessels, and that intermediate vessels be covered and controlled using a pressure/vacuum valve, at minimum, so that the vessels are not open to atmospheric pressure. This methodology is an alternative to gathering and evaluating liquid samples and may be used for systems that handle emulsions or single liquids.

The Greenhouse Gas and other compound emission rates are calculated using the measured annual vapor recovery gas volume metered by the system and an annual gas composition analysis. The annual measured gas volume is adjusted to account for capture efficiency of the vapor recovery system.

(a) Measure the annual gas volume recovered by the vapor recovery system using the calibrated meter outfitted with temperature and pressure gauges as described in Section 6.

(b) Obtain an annual gas sample of the vapor recovery gas and evaluate it for all gaseous compounds, the molecular weight, and the weight percent of Greenhouse Gases and other compounds.

(c) Calculate the annual emission rates as described in Section 10.2.

10. CALCULATING RESULTS

10.1 Flash Emission Calculation Methodology for Liquid Samples

The following is used in conjunction with vessel information and a laboratory analysis to calculate metric tons of Greenhouse Gases (CO_2 and CH_4) or short tons of other compounds (VOC_{C3-C9} or BTEX). The same formulas may be applied to crude oil, condensate, and produced water.

(a) If required, calculate the barrels per day of crude oil or condensate in emulsion using the Percent Water Cut:

$$Barrels / Day = (1 - Percent\ Water\ Cut)(Throughput) \quad \textbf{Equation 1A}$$

Where:

Barrels/Day = barrels per day crude oil or condensate

Percent Water Cut = percentage of produced water in emulsion

Throughput = barrels per day of emulsion

(b) If required, calculate the barrels per day of produced water in emulsion using the Percent Water Cut:

$$Barrels / Day = (Percent\ Water\ Cut)(Throughput) \quad \textbf{Equation 1B}$$

Where:

Barrels/Day = barrels per day produced water

Percent Water Cut = percentage of produced water in emulsion

Throughput = barrels per day of emulsion

(c) Calculate the total volume of gas produced per year:

$$Ft^3 / Year = (G)\left(\frac{Barrels}{Day}\right)\left(\frac{Days}{Year}\right) \quad \textbf{Equation 2}$$

Where:

Ft^3/Year = standard cubic feet of gas produced per year

G = Gas to Oil Ratio or Gas to Water Ratio (from lab analysis)

Barrels/Day = barrels per day crude oil, condensate, or produced water (Eq. 1A/1B)

Days/Year = days of operation per year

(d) Convert the total gas volume to pounds:

Equation 3

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year}\right)\left(\frac{gram}{gram-mole}\right)\left(\frac{gram-mole}{23.690\,l}\right)\left(\frac{28.317\,l}{Ft^3}\right)\left(\frac{lb}{454 grams}\right)$$

Where:

Mass $_{Gas}$ /Year = pounds of gas per year

Ft^3/Year = cubic feet of gas produced per year (Eq. 2)

Gram/Gram-Mole = Molecular Weight of gas sample (from lab analysis)

23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60^0F

(e) Calculate the mass of GHG or other compound:

$$Mass_{GHG} / Year = \left(\frac{WT\%\,GHG}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{metric\ ton}{2205\ lb}\right)$$ **Equation 4**

$$Mass_{Compound} / Year = \left(\frac{WT\%\,Compound}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{ton}{2000\ lb}\right)$$ **Equation 5**

Where:

Mass $_{GHG}$ /Year = metric tons of CO_2 or CH_4 (Eq. 4)

Mass $_{Compound}$ /Year = tons of other compound (Eq. 5)

Mass $_{Gas}$ /Year = pounds of gas per year (Eq. 3)

WT% GHG = Weight % of CO_2 or CH_4 (from lab analysis)

WT% Compound = Weight % of VOC_{C3-C9} or BTEX (from lab analysis)

(f) If a vapor recovery system is installed on the separator and tank system, adjust the annual emission rate as follows:

$$Emissions_{GHG/Compound} = (Mass_{GHG/Compound} / Year)(1 - CE)$$ **Equation 6**

Where:

Emissions $_{GHG/Compound}$ = controlled GHG or other compound emissions

Mass $_{GHG/Compound}$ /Year = uncontrolled GHG or other compound emissions per year (Eq. 4 or 5)

CE = capture and control efficiency of vapor recovery system

10.2 Emission Calculation Methodology Using Measured Vapor Recovery System Parameters

(a) Convert the total volume of vapor measured using the calibrated meter and average annual vapor temperature and pressure to standard conditions:

$$Ft^3 / Year = V\left(\frac{519.67}{T}\right)\left(\frac{P+14.696}{14.696}\right) \qquad \textbf{Equation 7}$$

Where:

Ft^3/Year = annual cubic feet of gas corrected to standard conditions (scf)

V = annual volume of gas going to the vapor recovery system, measured by the calibrated meter (cubic feet)

T = average annual vapor temperature measured at the meter (degrees R)

P = average annual gauge pressure measured at the meter (psig)

(b) Convert the total gas volume to pounds:

$$Mass_{Gas} / Year = \left(\frac{Ft^3}{Year}\right)\left(\frac{gram}{gram-mole}\right)\left(\frac{gram-mole}{23.690\,l}\right)\left(\frac{28.317\,l}{Ft^3}\right)\left(\frac{lb}{454\,grams}\right) \qquad \textbf{Equation 8}$$

Where:

Mass $_{Gas}$ /Year = pounds of gas per year

Ft^3/Year = cubic feet of gas produced per year (Eq. 6)

Gram/Gram-Mole = Molecular Weight of gas sample (from lab analysis)

23.690 l/gr-mole = molar volume of ideal gas at 14.696 psi and 60^0F

(c) Calculate the mass of GHG or other compound:

$$Mass_{GHG} / Year = \left(\frac{WT\%GHG}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{metric\ ton}{2205\,lb}\right) \qquad \textbf{Equation 9}$$

$$Mass_{Compound}/Year = \left(\frac{WT\%\,Compound}{100}\right)\left(\frac{Mass_{Gas}}{Year}\right)\left(\frac{ton}{2000\ lb}\right)$$ **Equation 10**

Where:

Mass $_{GHG}$ /Year = metric tons of CO_2 or CH_4 (Eq. 9)

Mass $_{Compound}$ /Year = tons of other compound (Eq. 10)

Mass $_{Gas}$ /Year = pounds of gas per year (Eq. 8)

WT% GHG = Weight % of CO_2 or CH_4 (from lab analysis)

WT% Compound = Weight % of $VOC_{C3\text{-}C9}$ or BTEX (from lab analysis)

(d) Adjust the annual emission rate as follows:

Equation 11

$$Emissions_{GHG/Compound} = \left(Mass_{GHG/Compound}/Year\right)\left(\frac{1-CE}{CE}\right)$$

Where:

Emissions $_{GHG/Compound}$ = uncaptured GHG or other compound emissions

Mass $_{GHG/Compound}$ /Year = captured GHG or other compound emissions per year (Eq. 9 or 10)

CE = capture efficiency of vapor recovery system.

11. REPORTING RESULTS

The results of this procedure are used to estimate or report emission rates of Greenhouse Gases or other compounds from separator and tank systems used in onshore crude oil or natural gas production, processing, or storage. All results shall be reported to at least three significant figures. All supporting information used to derive the emission estimates, including sample information, laboratory results, and calculations must be maintained by the reporting entity for a minimum of three years in order to reproduce the estimated or reported results. The following information must be maintained by the reporting entity:

11.1 **Crude Oil, Condensate, or Produced Water** (Section 10.1)

(a) Laboratory results specified in Section 12;

(b) All calculations and calculated results;

(c) A completed copy of Form 1;

(d) Annual emission rates of Greenhouse Gases and other compounds;

(e) Annual production of crude oil, condensate, and produced water; and

(f) API Gravity of crude oil or condensate.

11.2 Emulsion or Liquids under Vapor Recovery (Section 10.2)

(a) Laboratory results of an annual gas composition analysis or an average of multiple, more frequent samples within the year;

(b) Measured annual vapor recovery system gas throughput;

(c) All calculations and calculated results;

(d) Annual emission rates of Greenhouse Gases and other compounds; and,

(e) API Gravity of crude oil or condensate.

12. ANALYTICAL LABORATORY METHODS

12.1 Sample Preparation

(a) Prior to extracting liquid from a sample cylinder, the cylinder must be heated to the same temperature as measured at the time of sampling. The laboratory apparatus must be temperature and pressure controlled by a means that allows cooling and depressurizing liquid from sampling conditions to the standard temperature and pressure while precisely measuring liquid and gas volumes.

(b) Sample gases shall be collected in a closed system with a means of precisely measuring liquid and gas volume. Sample preparation guidance can be found in GPA 2174, GPA 2261 and GPA 2177.

12.2 Laboratory Methods

The following methods are required to evaluate and report flash emission rates from crude oil, condensate, and produced water. All methods and quality control requirements shall be conducted as specified in each method.

(a) Hydrogen Sulfide (Low-Level): Evaluate using EPA Method 15 and EPA Method 16 or use ASTM D-1945M (Thermal Conductivity Detector), ASTM D-5504 (sulfur chemiluminescence detector), and ASTM D-6228 (flame photometric detector) as alternate methods.

(b) Oxygen, Nitrogen, Carbon Dioxide, Hydrogen Sulfide (High-Level), Methane, Ethane, Propane, i-Butane, n-Butane, i-Pentane, n-Pentane,

Hexanes, Heptanes, Octanes, Nonanes, and Decanes+: Evaluate per ASTM D-1945, ASTM D-3588, and ASTM D-2597 (GC/TCD). Note: This analysis requires all three methods specified. The base method is ASTM D-1945, which is modified to extend the hydrocarbon analysis range based on information from the other two methods.

(c) BTEX: Evaluate per EPA 8021 B (GC/FID) or use ASTM D-3170, GPA 2286, EPA 8260B, EPA TO-14, and EPA TO-15 as alternate methods.

(d) API Gravity of liquid phase crude oil or condensate at 60 degrees Fahrenheit (60°F): Evaluate per ASTM D-287 using measured result of Specific Gravity. Note: If water is entrained in the sample, measure the API Gravity using ASTM D-287 (API Hydrometer) and calculate the Specific Gravity using the measured API Gravity.

(e) Specific Gravity of pre-flash liquid phase crude oil or condensate: Evaluate per ASTM D-4052, ASTM D-70, or ASTM D-5002 or calculate using results from ASTM D-287.

(f) Molecular Weight of gaseous phase by calculation per ASTM D-3588.

(g) Percent Water Cut: evaluate per ASTM D-4007 (Basic Sediment and Water).

12.3 Laboratory Reports

Any chromatograph system that allows for the collection, storage, interpretation, adjustment, or quantification of chromatograph detector output signals representing relative component concentrations may be used to conduct this procedure. The laboratory results must be reported as specified in Section 11. A laboratory report that provides the following minimum information described below and in Table 1 must be provided to the facility operator so they can calculate and report the results specified in Sections 10 and 11:

(a) The gaseous phase WT% of CO_2, CH_4, the gaseous phase WT% of C2 through C9 and C10+, the gaseous phase WT% of BTEX, and the gaseous phase WT% of O_2, N_2, and H_2S;

(b) The gaseous phase Gram Molecular Weight of the total gas sample;

(c) The liquid phase API Gravity of crude oil or condensate at 60°F;

(d) Volumetric Gas to Water Ratio (GWR) for produced water; and,

(e) Volumetric Gas to Oil Ratio (GOR) for crude oil or condensate.

Table 1

Flash Analysis Sampling and Laboratory Requirements

Sampling Technician Needs to Obtain from Operator Before Sampling Can Occur:
Vessel Description
Vessel Throughput (Barrels/Day)
Percent Water Cut
Number of Days in Operation
Vapor Recovery System Information (downstream vessels) • Presence of VR System • Vapor Processing & Type • Vapor End Use(s)
Tentatively Identified Compound List (if sampling proprietary compounds)

Gas Evolved from Crude Oil, Condensate, or Produced Water
WT% CO2, CH4
WT% C2-C9, C10+
WT% BTEX
WT% O2
WT% N2
WT% H2S
Molecular Weight Total Gaseous Sample
Gas to Oil Ratio
Gas to Water Ratio

Pre-Flash Liquid Crude Oil or Condensate
API Gravity

13. REFERENCES

ASTM D-70	*Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method)*
ASTM D-287	*Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method)*
ASTM D-1945M	*Standard Test Method for Analysis of Natural Gas by Gas Chromatography*
ASTM D-2597	*Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*
ASTM D-3710	*Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography*
ASTM D-3588	*Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels*
ASTM D-4007	*Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method*
ASTM D-4052	*Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter*
ASTM D-5002	*Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer*
ASTM D-5504	*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence*
ASTM D-6228	*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection*
EPA Method 15	*Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources*
EPA Method 16	*Semicontinuous Determination of Sulfur Emissions from Stationary Sources*
EPA Method 8021B	*Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/Or Electrolytic Conductivity Detectors*

EPA Method 8260B	*Volatile Organic Compounds By Gas Chromatography/Mass Spectrometry (GC/MS)*
EPA Method TO-14	*Determination Of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters With Subsequent Analysis By Gas Chromatography*
EPA Method TO-15	*Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS)*
GPA 2174	*Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography*
GPA 2177	*Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography*
GPA 2261	*Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography*
GPA 2286	*Extended Gas Analysis Utilizing a Flame Ionization Detector*

Form 1

Crude Oil, Condensate, and Produced Water Sampling Field Data Sheet

(report measured results to at least three significant figures)

Facility Contact Information:

Facility Name: _____

Address: _____

City: _____ State: _____

Zip: _____ Phone: _____

Facility Contact: _____

Sampling Company:

Company Name: _____

Address: _____

City: _____ State: _____

Zip: _____ Phone: _____

Sampling Technician: _____

Sample Information:

Sample Type: _____ (crude oil, condensate, produced water)

Date: _____

Time: _____ Sample Temperature: _____ Deg. F

Cylinder Number: _____ Sample Pressure: _____ PSI

Field Name: _____ (field from where sample was taken)

Separator Information:

Separator Type: _____ (e.g., heater/treater)

Separator Throughput: _____ (barrels/day)

Percentage Water Cut _____ % Days in Operation/Year: _____

Vapor Recovery (VR) System (downstream of sample vessel):

VR System Installed: Yes No

Vapor Processing & Type: Yes No List Type(s): _____
(Sulfa Treat, Amine, etc.)

Vapor End Use(s) (list): _____
(sales gas, flare, engine, boiler, etc.)

Shipping Information:

Shipping Company: _____

Tracking Number: _____

TITLE 17: CALIFORNIA AIR RESOURCES BOARD

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

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider proposed amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to: allow for additional transition assistance for covered entities, add a new offset protocol, and incorporate additional cost containment features.

DATE: October 24, 2013

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

WEBCAST: http://www.calepa.ca.gov/broadcast/?BDO=1

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m. October 24, 2013, and may continue at 8:30 a.m. on October 25, 2013. This item may not be considered until October 25, 2013. Please consult the agenda for the hearing, which will be available at least 10 days before October 25, 2013, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW PURSUANT TO GOVERNMENT CODE 11346.5(a)(3)

Sections Affected: Proposed amendments to sections 95802, 95811, 95812, 95813, 95814, 95821, 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, and 96022, title 17, California Code of Regulations. Proposed adoption of new sections 95894, 95895, 95923, 95979.1, Appendix B, and Appendix C, title 17, California Code of Regulations. Proposed adoption of the incorporated California Air

Resources Board Compliance Offset Protocol Mine Methane Capture Projects: Capturing and Destroying Methane From U.S. Coal and Trona Mines (2013).

Documents Incorporated by Reference:

The following documents are hereby proposed for incorporation by reference by ARB into the Staff Report for the proposed amendments to the regulation and the proposed Compliance Offset Protocol:

1. American Association of Petroleum Geologists (1991). Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10. October 1991. (California Air Resources Board Compliance Offset Protocol Mine Methane Capture Projects: Capturing and Destroying Methane From U.S. Coal and Trona Mines (2013))
2. American Society for Testing and Materials Designation (2005). ASTM D388-05 Standard Classification of Coals by Rank. (California Air Resources Board Compliance Offset Protocol Mine Methane Capture Projects: Capturing and Destroying Methane From U.S. Coal and Trona Mines (2013))
3. 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)
4. 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)
5. California Air Resources Board Compliance Offset Protocol Mine Methane Capture Projects: Capturing and Destroying Methane From U.S. Coal and Trona Mines (2013). (Proposed in section 95973, title 17, California Code of Regulations) http://www.arb.ca.gov/cc/capandtrade/protocols/mmcprotocol.htm.
6. California Energy Commission (2013). Guidelines for California's Solar Electric Incentive Programs (Senate Bill 1), 5th Edition. June 2013. Publication Number: CEC-300-2013-008-ED5-CMF. (section 95841.1, title 17, California Code of Regulations) http://www.energy.ca.gov/2012publications/CEC-300-2012-008/CEC-300-2012-008-ED5-CMF.pdf
7. California Energy Commission (2013). Renewables Portfolio Standard Eligibility Guidebook, 7th Edition. Efficiency and Renewable Energy Division. April 2013. Publication Number: CEC-300-2013-005-ED7-CMF (section 95852.1.1, title 17, California Code of Regulations) http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-CMF.pdf

8. California Public Utilities Commission (2010). Decision 10-12-035 Adopting Proposed Settlement. Issued December 21, 2010. (section 95802, title 17, California Code of Regulations) https://www.sce.com/wps/wcm/connect/d63903ad-925d-4a1c-a2b5-62c261a3a82c/CPUC_D_1012035.pdf?MOD=AJPERES
9. International Standards Organization (2010). Tissue paper and tissue products-Part 8: Water-absorption time and water-absorption capacity, basket emersion test method. 12625-8: 2010. (section 95802, title 17, California Code of Regulations)

Background and Effect of the Proposed Rulemaking

The California Global Warming Solutions Act of 2006 (Assembly Bill 32; Stats. 2006, Chapter 488) (AB 32) authorizes ARB to implement a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California. AB 32 required ARB to develop a scoping plan to reduce GHG emissions in California to 1990 levels by 2020. ARB's adopted Scoping Plan includes a comprehensive set of actions designed to reduce GHG emissions in California, improve the environment, reduce dependence on foreign oil, diversify energy sources, save energy, create new jobs, and enhance public health. Meeting the goals of AB 32 requires a coordinated set of strategies to reduce GHG emissions throughout the economy that work within a comprehensive tracking, reporting, verification and enforcement framework. The Scoping Plan includes a variety of measures to achieve AB 32 goals, including direct regulations, performance-based standards, and market-based mechanisms. Many of the measures in the Scoping Plan complement and reinforce each other.

The Scoping Plan identified a cap-and-trade regulation (Regulation) as one of the most important strategies for achieving emissions reductions at least cost. As envisioned in the Scoping Plan, the cap and trade program would eventually be linked with cap and trade programs operating in other states and provinces. The Regulation provides a fixed limit on GHG emissions from the sources responsible for about 85 percent of the State's total GHG emissions. The Regulation reduces GHG emissions by applying a declining aggregate cap on GHG emissions, and creates a flexible compliance system through the use of tradable instruments (allowances and offset credits). The Regulation is designed to link with partners in other jurisdictions. The California Cap-and-Trade Regulation went into effect January 1, 2012.

In 2012, ARB staff proposed two sets of amendments to the Regulation. The first set was focused on implementation requirements and the second on linking the California and Québec cap-and-trade programs. At its June 2012 Board hearing, the Board

approved the implementation amendments, which became effective September 1, 2012. At its April 2013 Board hearing, the Board approved the linkage amendments. The linkage amendments become effective October 1, 2013, with a linked California and Québec cap-and-trade program effective on January 1, 2014.

In developing the proposed amendments described in this notice, staff held nine workshops and released discussion draft regulation amendments for public comment. ARB received more than 75 written comments on the discussion draft amendments and met regularly with stakeholders to discuss concerns and recommendations. The proposed amendments provide additional process for clarity in implementation, address stakeholder concerns on cost containment, add a new compliance offset protocol, and extend transition assistance for covered entities in the program. In a separate rulemaking action, ARB is amending its mandatory reporting regulation to support some of these proposed changes to the cap-and-trade program.

Objectives and Benefits

The purpose of these amendments is to enhance implementation and oversight of the Cap-and-Trade Program. The proposed amendments also address stakeholder concerns related to cost containment and offset supply. To that effect, staff is proposing amendments to the Regulation, including those related to allocation, market program implementation, and offset program implementation. Staff has proposed allocation for additional sectors, changes to allocation methodologies, and changes to transition assistance for existing sectors. Proposed amendments for market provisions relate to implementation, auctions and reserve sales, additional information reporting, cost containment, and enhancements to support market oversight. Staff has also proposed clarifications and new provisions to help implement the offset program. Staff has proposed amendments that will shift the scheduled reduction in allowance allocation assistance factors by one compliance period. This shift is intended to provide additional time and certainty to industry in making necessary investments in efficiency and emission reducing technologies. Details regarding the proposed amendments are included in Chapter II: Summary of Proposed Action and in Appendix A of the Staff Report. Staff is also proposing a new protocol related to mine methane capture that will provide additional supply of compliance instruments to the market within the existing 8 percent offset limit.

Anticipated benefits of the proposed amendments include improved clarity for covered entities regarding the allocation of emission allowances, timelines for compliance, offset program implementation and verification, cost containment, enhanced market monitoring and program oversight, and clarity in the emissions reductions required by the program. Given the GHG emissions reductions which will occur because of the

program, these amendments may also directly improve the health and welfare of California residents, worker safety, and the State's environment. Specific discussion of the proposed amendments follows.

Resource Shuffling

Per Board Resolution 12-33, the Board directed staff to continue to work with the Emissions Markets Advisory Committee (EMAC), the California Independent System Operator (CAISO), State agencies and stakeholders to provide certainty to the electricity market about how the Regulation will address resource shuffling. The Board also directed staff to further refine the definition of resource shuffling and to identify situations that ARB would not consider resource shuffling. Recommended actions were presented to the Board at the October 2012 Board meeting. Based on these recommended actions, staff developed guidance for the definition of resource shuffling, and identified "safe harbors," or activities that covered entities may engage in that ARB does not consider resource shuffling. Staff has proposed clarifying amendments to the Regulation consistent with the previously recommended actions and published guidance regarding the definition of resource shuffling and the identified safe harbors.

Legacy Contracts

Per Board Resolution 12-33, the Board directed staff, in coordination with the California Public Utilities Commissions (CPUC), 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. Staff evaluated existing legacy contract issues and has proposed methodologies to be included in the Regulation that provide transition assistance through free allocation of allowances to those covered entities with legacy contracts, and through changed allocation of allowances to legacy contract counterparties.

Combined Heat and Power

Per Board Resolution 12-33, the Board directed staff to work with the CPUC, the California Energy Commission (CEC), and stakeholders to develop a methodology that exempts the steam and waste heat emissions for all facilities that would not be included in the Cap-and-Trade program "but for" their investment in combined heat and power (CHP). Staff has proposed a methodology and regulatory language that provides for a process to quantify emissions eligible for the exemption and to retire equivalent allowances in order to maintain the environmental integrity of the Program.

Emissions Leakage

Per Board Resolutions 12-33 and 11-32, the Board directed staff to continue to evaluate trade exposure categorization and, if necessary, modify the leakage risk determinations to be implemented prior to the allocation of allowances for the second compliance period. The Board further directed staff to complete current studies of leakage risk and evaluate options for ensuring the competitiveness of California industries. Staff has proposed new and modified leakage risk determinations based on the status of current studies under contract to ARB. In addition, staff proposed to increase the assistance factor to 100% throughout the second compliance period for those sectors defined at medium- and low-leakage risk. The third compliance period assistance factor was increased to match the previous assistance factor for the second compliance period for each the respective sector. This change was in recognition of the need for regulatory certainty for businesses while the new leakage studies are completed.

Universities

Per Board Resolution 12-33, the Board directed staff to develop a methodology to allocate allowances to California universities that recognizes early actions by universities to reduce greenhouse gas (GHG) emissions, and invest in energy efficiency and CHP. Staff has proposed a methodology for the direct allocation of allowances to California universities that are covered entities as a result of early action GHG reduction activities.

Offset Program Implementation

Staff has evaluated and proposed amendments which clarify processes related to offset program implementation. These amendments address project listing requirements, monitoring and reporting requirements, verification body requirements, conflict of interest requirements, compliance offset credit issuance, timing and deadlines, and roles of air districts. Staff has also proposed changes to clarify the invalidation requirements to be consistent for all project types.

Cost Containment

Per Board Resolution 12-51, staff has proposed amendments to further ensure that allowance prices will not exceed the highest price tier of the Allowance Price Containment Reserve while minimizing the impact on existing allowances and maintaining the environmental integrity of the Program.

Product-Based Benchmarks

Per Board Resolution 11-32, the Board directed staff to identify and propose new benchmarks and allowance allocation for manufacturing of new products in California. Staff is proposing new product benchmarks for various sectors, including those sectors for which data was not previously collected through the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.), but which may be eligible for free allocation and for activities currently under the energy-based methodology of allowance allocation. Staff has also proposed changes to certain existing benchmarks based on newly available data, where appropriate.

Allowance Allocation

Per Board Resolution 11-32, the Board directed staff to continue to work with stakeholders to further develop the allowance allocation approach for the petroleum refining sector in the second and third compliance period. Staff is proposing modifications to the true-up methodology and considering changes to the allocation methodology associated with refinery allowance allocation using a carbon weighted approach. Staff is also proposing an allocation methodology for suppliers of natural gas, which will have a compliance obligation beginning with the second compliance period. Finally, staff is proposing an allocation methodology for public wholesale water agencies for the protection of water ratepayers.

Waste-to-Energy

Per Board Resolution 12-33, the Board directed staff to develop regulatory amendments to exempt waste-to-energy facilities from the program for the first compliance period. Staff has proposed an exemption of emissions from waste-to-energy facilities, including modifications to require the retirement of allowances associated with the exempted emissions.

Renewable Energy Credits

Staff proposes clarifications to requirements for the retirement of Renewable Energy Credits (REC's) to ensure that REC's are not used to account for zero emissions in multiple programs. Staff has proposed modifications to ensure the retirement requirements are consistently applied to both in-state and out-of-state electrical generation facilities that import electricity to California.

Implementation of Auction and Trading Requirements

Staff has proposed modifications related to the implementation of the auction and trading provisions within the Auction Platform and Compliance Information Tracking Services System (CITSS). Staff also proposed modifications to the current schedule for auctions and reserve sales.

Compliance Obligation Surrender

Staff has proposed requirements and a process for the surrender of compliance instruments for the annual and triennial surrender obligation requirements. These amendments include provisions that specify which instruments are eligible for use, the order of retirement of instruments in the compliance account, and limited future borrowing in cases of allocation true-up.

Compliance Instrument Tracking System Service and Information Disclosure

Staff has proposed modifications to the existing information disclosure requirements and new requirements to ensure rigorous oversight of the market program and of actions taken in the tracking system. Staff has proposed additional information disclosure requirements to help ARB monitor relationships between consultants and market participants.

Market Rules

Staff is proposing modifications to the existing information requirements related to CITSS instrument transfers to aid implementation. These requirements may be used to monitor the market and provide public reports for program transparency. Staff is also proposing modifications to the auction purchase limits.

New Offset Protocol

Staff has proposed to add quantification methodologies for one new proposed Compliance Offset Protocol for mine methane capture projects. A detailed analysis of this protocol is included in Attachment A of the Staff Report.

DETERMINATION OF INCONSISTENCY AND INCOMPATIBILITY WITH EXISTING STATE REGULATIONS

During the process of developing the proposed regulatory action, ARB has conducted a search of any similar regulations on this topic and has concluded that these regulations are neither inconsistent nor incompatible with existing state regulations.

MANDATED BY FEDERAL LAW OR REGULATION

This regulation is not mandated by federal law or regulations

COMPARABLE FEDERAL REGULATIONS

There are no comparable federal regulations.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The report is entitled, Staff Report: Initial Statement of Reasons for the Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms.

Copies of the ISOR and the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, may be accessed on ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990, on September 4, 2013.

Final Statement of Reasons Availability

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on ARB's website listed below.

Agency Contact Persons

Inquiries concerning the substance of the proposed regulation may be directed to Ms. Rajinder Sahota, Manager of the Climate Change Program Monitoring Section at (916) 323-8503 or Ms. Elizabeth Scheehle, Manager of the Climate Change Program Development Section at (916) 322-7630.

Further, the agency representative and designated back-up contact persons, to whom non substantive inquiries concerning the proposed administrative action may be directed is Ms. Amy Whiting, Regulations Coordinator, at (916) 322-6533. The Board staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

Internet Access

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at http://www.arb.ca.gov/regact/2013/capandtrade13/capandtrade13.htm

DISCLOSURES REGARDING THE PROPOSED REGULATION

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Fiscal Impact / Local Mandate

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would not create costs and may create some savings to covered State agencies. The proposed regulatory action would not create costs or saving in federal funding to the State, costs or mandate to any local agency or school district, whether or not reimbursable by the State pursuant to Government Code, title 2, division 4, part 7 (commencing with section 17500), or other nondiscretionary cost of savings to State or local agencies.

SIGNIFICANT STATEWIDE ADVERSE ECONOMIC IMPACT DIRECTLY AFFECTING BUSINESS, INCLUDING ABILITY TO COMPETE

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons. In fact, an express purpose of the proposed amendments is to ensure that California businesses' ability to compete is not directly affected.

COST IMPACTS ON REPRESENTATIVE PRIVATE PERSONS OR BUSINESSES

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts to representative private persons or businesses. The ARB is not aware of any cost impacts that a representative private person or business would necessarily incur in reasonable compliance with the proposed action.

STATEMENT OF THE RESULTS OF THE ECONOMIC IMPACT ASSESSMENT PREPARED PURSUANT TO GOVERNMENT CODE SEC. 11346.3(b)

Effect on Jobs/Businesses:

The Executive Officer has determined that the proposed regulatory action would not affect the creation or elimination of jobs within the State of California, the creation of new business or elimination of existing business within the State of California, or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

Benefits of the Proposed Regulation:

The objective of the proposed amendments to the regulation is to provide additional transition assistance to covered entities, additional cost containment mechanisms and aid in implementation in oversight of the regulation.

A summary of these benefits is provided, please refer to "Objectives and Benefits", under the Informative Digest of Proposed Action and Policy Statement Overview Pursuant to Government Code 11346.5(a)(3) discussion on page 4 of this notice.

A detailed assessment of the economic impacts of the proposed regulatory action can be found in Chapter IV of the ISOR, Economic Impacts of the Proposed Regulation.

EFFECT ON SMALL BUSINESS

The Executive Officer has also determined, pursuant to California Code of Regulation, title 1, section 4, that the proposed regulatory action would not affect small businesses because small businesses in regulated sectors would generally not be subject to the proposed regulation. In general, the total GHG emissions for small businesses are below the GHG reporting threshold, thereby exempting them from compliance obligations under the proposed regulation.

HOUSING COSTS

The Executive Officer has also made the initial determination that the proposed regulatory action will not have a significant effect on housing.

BUSINESS REPORT

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

ALTERNATIVES

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board, or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed, would be as effective and less burdensome to affected private persons than the proposed action, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provision of law.

ENVIRONMENTAL ANALYSIS

In accordance with ARB's certified regulatory program, California Code of Regulations, title 17, sections 60006 through 60007, and the California Environmental Quality Act, Public Resources Code section 21080.5, ARB has conducted an analysis of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulatory action. The environmental analysis of the proposed regulatory action can be found in Chapter III of the ISOR.

WRITTEN COMMENT PERIOD AND SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting and may provide comments by postal mail or by electronic submittal before the meeting. The public comment period for this regulatory action will begin on September 9, 2013. To be considered by the Board, written comments, not physically submitted at the meeting, must be submitted on or after September 9, 2013 and received no later than 12:00 noon on October 23, 2013, and must be addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

You can sign up online in advance to speak at the Board meeting when you submit an electronic board item comment. For more information go to: http://www.arb.ca.gov/board/online-signup.htm.

Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

ARB requests that written and email statements on this item be filed at least 10 days prior to the hearing so that ARB staff and Board members have additional time to consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

Additionally, the Board requests but does not require that persons who submit written comments to the Board reference the title of the proposal in their comments to facilitate review.

AUTHORITY AND REFERENCE

This regulatory action is proposed under the authority granted in Health and Safety Code, sections 38510, 38560, 38562, 38564, 38570, 38571, 38580, 39600, 39601, and section 16428.8 Government Code. This action is proposed to implement, interpret, and make specific sections 38530, 38560.5, 38564, 38565, 38570 and 39600 of the Health and Safety Code.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, Government Code, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340).

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice and that the regulatory language as modified could result from the proposed regulatory action; in such event, the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15-days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Consistent with California Government Code Section 7296.2, special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format or another language; or
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at 916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Consecuente con la sección 7296.2 del Código de Gobierno de California, una acomodación especial o necesidades lingüísticas pueden ser suministradas para cualquiera de los siguientes:

- Un intérprete que esté disponible en la audiencia
- Documentos disponibles en un formato alterno u otro idioma
- Una acomodación razonable relacionados con una incapacidad

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envié un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD

Richard W. Corey
Executive Officer

Date: August 27, 2013

State of 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

Release Date: September 4, 2013

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State of California

AIR RESOURCES BOARD

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

PUBLIC HEARING TO CONSIDER PROPOSED AMENDMENTS TO THE CALIFORNIA CAP-AND-TRADE PROGRAM

DATE OF RELEASE: September 4, 2013
SCHEDULED FOR CONSIDERATION: October 24, 2013

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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Acknowledgments

This report was prepared with the assistance and support from many individuals within the Air Resources Board. In addition, staff would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations, too numerous to list, whose contributions throughout the development process have been invaluable.

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EXECUTIVE SUMMARY

The California Global Warming Solutions Act of 2006, (AB 32, Nuñez, Chapter 488, Statutes of 2006) as codified at California Health and Safety Code sections 38500 *et seq.*, (AB 32) requires California to reduce greenhouse gas emissions (GHG) to 1990 levels by 2020 and to develop a comprehensive strategy to reduce dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and public health. AB 32 also requires the Air Resources Board (ARB or Board) to work with other states and nations to identify and facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.

The Cap-and-Trade Program (Program) is a key element of California's GHG reduction strategy. It establishes a declining limit on 85 percent of statewide GHG emissions, and creates a powerful economic incentive for major investment in cleaner, more advanced technologies. The Cap-and-Trade Program also gives businesses the flexibility to choose the lowest-cost approach to reducing emissions.

This report presents the staff proposal to amend the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (Cap-and-Trade Regulation or Regulation) to provide additional transition assistance to covered entities, the adoption of a new offset protocol, additional cost containment mechanisms, new provisions regarding implementation, and oversight of the Regulation.

A. Background

California's Cap-and-Trade Regulations were adopted by ARB in October 2011. The Regulations took effect on January 1, 2012. The first auction of emission allowances occurred in November 2012, and the first compliance period began on January 1, 2013.

As previously noted, the Program establishes a hard declining cap on approximately 85 percent of total statewide GHG emissions. ARB will issue allowances equal to the total amount of permissible emissions over a given compliance period. One allowance equals one metric ton of GHGs. As the cap declines over time, fewer allowances will be issued, ensuring that emission reductions occur.

Under the Program, companies do not have individual or facility-specific reduction requirements. Rather, all companies covered by the Regulation are required to surrender allowances in an amount equal to their total GHG emissions during each compliance period. Companies can also meet a portion of their compliance

requirements by surrendering offset credits, which are rigorously verified emission reductions that occur from projects outside the scope of the Cap-and-Trade program.

The Program gives companies the flexibility to trade allowances with others or take steps to cost-effectively reduce emissions at their own facilities. Companies that emit more will need to turn in more allowances or offset credits. Companies that can cut their emissions will need to surrender fewer allowances. As the cap declines, aggregate emissions must be reduced.

California's cap-and-trade program is purposely designed to leverage the power of the market in pursuit of an environmental goal. It opens the door for major investment in emissions-reducing technologies, and sends a clear economic signal that these investments will be rewarded.

The Program is designed with an eye toward inclusion within a larger regional trading program. Since 2007, California has been a partner in the Western Climate Initiative, an effort of US states and Canadian Provinces (including Québec) working together to implement policies to combat climate change, including through the development of a regional cap-and-trade system. The Program works with WCI on implementation issues to ensure rigorous and compatible systems are in place.

B. Previous Amendments to the Cap-and-Trade Regulation (2012)

In 2012, ARB proposed two sets of amendments to the Cap-and-Trade Regulation. The first set of amendments, related to program implementation, was approved by the Board in June 2012. These amendments took effect in September 2012. The second set of amendments, related to jurisdictional linkage with Québec, was approved by the Board in April 2013. These amendments will take effect in October 2013 and specify a January 1, 2014 start date for the linked California and Québec Cap-and-Trade Programs.

C. Proposed Amendments to the Cap-and-Trade Regulation

In response to continued Board direction and further discussions with stakeholders, staff began a public process to propose additional amendments for Board consideration in Fall 2013. The section below provides a brief list of the regulatory amendments staff is proposing.

Staff Proposal

The staff proposal is to amend the California Cap-and-Trade Regulation to provide additional details to clarify implementation, address stakeholder concerns on cost containment, extend the transition assistance for covered entities in the program and

enhance ARB's ability to oversee and implement the Regulation. Specifically, the proposed amendments 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 AB 32;
- 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.

Staff Recommendation

Staff recommends that the Board adopt the proposed Regulation amendments. Climate change is a global problem that requires action by states, provinces, and nations. The proposed regulatory amendments allow for additional transition assistance to covered entities, add a new offset protocol, cost containment mechanisms, and enhance ARB's ability to implement and oversee the Regulation. In doing so, the amendments to the Program will enable the program to run smoothly and reduce GHG emissions while minimizing leakage and providing transitional assistance that can enable our economy to benefit from investment in clean energy technologies.

I. BACKGROUND AND INTRODUCTION

This Staff Report presents ARB staff's rationale to amend the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (Regulation) to include implementation changes, board direction, and additional cost containment mechanisms.

This introduction describes the structure of the Staff Report and provides a discussion of the public problem that the proposed amendments address, background information on California's Climate Change Scoping Plan, similar background information regarding the Regulation, the objectives of the proposed amendments, and the public process used to develop the Cap-and-Trade Program.

This Staff Report, including the attached appendices, represents the Initial Statement of Reasons (ISOR) for Proposed Rulemaking required by the California Administrative Procedure Act (Government Code section 11340 et seq).

The Staff Report is divided into the following chapters:

- Chapter I. Background and Introduction – Describes the public problem this Regulation seeks to address, provides background on California's Climate Change Scoping Plan, the Western Climate Initiative, and the public process used to develop the amendments.

- Chapter II. General Summary of the Proposed Amendments – Discussion of the main amendments proposed in the Regulation.

- Chapter III. Environmental Impacts of the Proposed Amendments – Describes potential impacts that the proposed Regulation may have on the environment, including potential impacts from project-specific activities.

- Chapter IV. Economic Impacts of the Proposed Amendments – Describes the economic impacts of the amendments

- Chapter V. Analysis of Alternatives to the Proposed Amendments – Describes alternative amendments that were considered and why the alternatives are less effective.

- Chapter VI. Summary and Rationale for the Proposed Amendments – Summarizes the proposed changes to the regulation and describes the rationale for each specific proposed amendment.

- Chapter VII. References – Provides a list of references used for development of the Staff Report.

- Appendices include the proposed Regulation amendments, the separate Staff Reports prepared for the Mine Methane Capture Offset Protocol, and information on product-based benchmark development, leakage risk classification for additional sectors, market coordination with WCI Partners, and information related to cost containment.

A. Description of the Public Problem

Climate change is one of the most serious environmental threats facing the world today. Global warming is already impacting the Western United States, particularly California, in more severe ways than the rest of the country. The 2010 Climate Action Team (CAT) report (CAT 2010) concluded that climate change will affect virtually every sector of the state's economy and most of our ecosystems. Significant impacts will likely occur even under moderate scenarios of increasing global GHG emissions and associated climate change. Compared to the rest of the country, California is particularly vulnerable to significant resource and economic impacts from at least three effects of climate change. First, as sea level rise and coastal erosion and flooding increase, California (with its long coastline) will experience loss of, and damage to, coastal property, infrastructure, recreational beaches, wildlife habitat, and coastal water supplies. Second, California relies on its snowpack for water supply and storage, and this resource is predicted to decrease substantially this century. Third, California's urban, suburban, and rural areas are highly impacted by wildfires in ways most of the country simply does not face, and climate change will increase the incidence and severity of wildfires and resulting air quality and economic impacts. California's Office of Environmental Health Hazard Assessment recently published a report on indicators of climate change. Many indicators reveal current potential impacts of climate change (OEHHA, 2013)

North America is also experiencing the effects of climate change. Annual mean air temperature in North America has increased over the past forty years (Füssel 2009; Pederson et al. 2010). More frequent and intense extreme weather events have impacted ecosystems, increased coastal damage, and affected a considerable proportion of people (Christensen et al. 2007; Emanuel et al. 2008).

Extreme weather events have also had severe impacts on transportation systems, energy supplies, and other industries in North America. For example, major hurricanes in 2004 and 2005 in the United States affected oil and natural gas platforms and

pipelines, creating billions of dollars in restoration costs for public utilities and transportation networks on the regional and national level (EEI 2005).

More cities are forecast to experience extreme heat waves, increasing sea levels, increased numbers of dangerous storm surges, water shortages, droughts, and increased flooding. In addition, severe heat waves, extreme weather events, and air pollution generated by climate change may cause social disruption and increase human losses and injuries, as well as vector-borne diseases.

It is important that California works to reduce GHG emissions in order to decrease the probability of these impacts.

B. Background

Seven years ago the California Global Warming Solutions Act of 2006 (AB 32, Nuñez, Chapter 488, Statutes of 2006) was enacted to begin addressing this public problem by reducing GHG emissions in a cost-effective manner. AB 32 encouraged ARB to continue to be a global leader in climate change mitigation and to develop integrated and cost-effective regional, national, and international greenhouse gas reduction programs (AB 32, Nuñez, Chapter 488, Statutes of 2006). The amendments proposed in this Regulation further our progress towards this goal by allowing additional transition assistance to covered entities, the addition of a new offset protocol, cost containment, and implementation and oversight the Regulation.

The California Climate Change Scoping Plan laid out a comprehensive program to reduce California's greenhouse gas emissions to 1990 levels by 2020, reduce California's dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and public health. The coordinated set of policies in the Scoping Plan employ strategies tailored to specific needs, including market-based compliance mechanisms, performance standards, technology requirements, and voluntary reductions. The Scoping Plan described a conceptual design for a cap-and-trade program that included eventual linkage to other cap-and-trade programs to form a larger regional trading program. ARB is working with other agencies to update the Scoping Plan this year. This update will provide a status report on progress in meeting the 2020 goals and lay the groundwork for meeting California's long-term climate goals.

C. Cap-and-Trade Regulation

In October 2011, the Board adopted the California Cap-and-Trade Regulation. The cap-and-trade program is a key element of California's climate strategy. It creates an aggregate GHG emission limit on the sources responsible for 85 percent of California's GHG emissions, establishes a price signal needed to drive long-term investment in

cleaner fuels and more efficient use of energy, and affords those regulated by the program flexibility to seek out and implement the lowest-cost options to reduce emissions. The Cap-and-Trade program was designed to work in concert with other measures, such as standards for cleaner vehicles, low-carbon fuels, renewable electricity, and energy efficiency. The program also complements and supports California's existing efforts to reduce criteria and toxic air pollutants. California's Cap-and-Trade Regulation was developed concurrently with WCI design documents that describe a template for a regional cap-and-trade program.

In 2012, ARB proposed two sets of amendments to the Cap-and-Trade Regulation. The first set of amendments, related to program implementation, was approved by the Board in June 2012. The second set of amendments, related to jurisdictional linkage with Québec, was approved by the Board in April 2013.

In response to continued Board direction and further discussions with stakeholders, staff began a public process to propose additional amendments for Board consideration in Fall 2013. This Staff Report presents these amendments to the Regulation, provides staff's rationale for making these changes, and provides additional information on these changes if available.

D. Western Climate Initiative and Linkage with Québec

The WCI was initiated in February 2007 as a collaboration of independent jurisdictions working together to identify, evaluate, and implement policies to tackle climate change at a regional level, including the design and implementation of a market-based mechanism, such as a regional cap-and-trade program. As previously discussed, the Board approved linkage of California's Cap-and-Trade Program with Québec's in April 2013. Prior to voting on linking California and Québec's programs, ARB made a request to the Governor to make the required findings under Senate Bill 1018. The findings under Senate Bill 1018 are required in order to link California's program with any other jurisdictional program. The Governor must find that the other jurisdiction's program is equivalent or stricter than California's program, linking will allow California to enforce AB 32 to the maximum extent feasible under the United States and California Constitutions against an entity located in a linked jurisdiction, the enforceability of the jurisdiction's program is equivalent or stricter than that required under California's program, and linkage would not impose liability on California. The Québec linkage amendments become effective October 1, 2013 with a linked California and Québec Cap-and-Trade program effective on January 1, 2014. To ensure continued harmonization between the programs, ARB has consulted with Québec on the proposed amendments and will continue to coordinate with Québec to ensure a smooth functioning of the linked program consistent with the requirements in SB 1018.

E. Public Process for Development of Amendments

ARB staff developed the proposed amendments through an extensive public process. Many of the proposed amendments were developed in response to Board direction through Resolutions, further discussions with stakeholders, and staff analysis.

Since approval of the 2012 amendments to the Cap-and-Trade Regulation relating to implementation and linkage, three subsequent public Board hearings have addressed ongoing program development. At the September 2012 and October 2012 Board hearings, the Board provided direction to ARB staff in the form of two Board Resolutions. Board Resolution 12-51 and Board Resolution 12-33 directed staff to analyze and, if necessary, propose amendments relating to resource shuffling, legacy contracts, combined heat and power, emissions leakage, allowance allocation to universities, cost containment, product-based benchmarks, and waste-to-energy facilities. In addition, Board Resolutions 11-32 and 12-33 also directed ARB staff to reconsider leakage risk determinations, the allowance allocation approach, and product benchmarks, as necessary. In response to these Board directives, staff began to identify and assess areas of the Regulation that might require amendments. A full list of topics for the proposed regulatory amendments, including those proposed as a result of Board direction through Resolutions, was initially described in the public document *Topics Subject to Potential Regulatory Amendments California Cap-and- Trade Regulation.* This document was posted on the Cap-and-Trade webpage for public review in May 2013 to allow for stakeholder comments and feedback early in the regulatory process.[1]

Starting in late 2012, staff held public workshops focused on specific topics that are the subject of the proposed amendments. Ten public workshops were held in 2012 and 2013 to present the proposed amendments and solicit public and stakeholder feedback. These are identified below:

- July 30, 2012: Cap-and-Trade Technical Workshop to Discuss Emissions Leakage
- August 28, 2012: Cap-and-Trade Technical Workshop to Discuss Refinery Benchmark in the Second Compliance Period
- January 25, 2013: Public Information Sharing in California's Cap-and-Trade Program
- March 28, 2013: Public Workshop on Addition of New Offset Protocols to the California Greenhouse Gas Cap-and-Trade Program

[1] http://www.arb.ca.gov/cc/capandtrade/2013summary.pdf

- May 1, 2013: Public Meeting to Discuss Universities, Legacy Contracts, and 'But for CHP' under the Cap-and-Trade Program
- June 3, 2013: Natural Gas Supplier Workshop
- June 25, 2013: Public Workshop on Compliance Retirement, Market-Related Reporting, and Cost Containment
- July 18, 2013: Public Workshop on Proposed Amendments to the California Cap-and-Trade Program
- August 13, 2013: Public Workshop on Refineries and Related Industries
- August 19, 2013: Public Workshop on Potential New Compliance Offset Protocols

ARB made available documents and presentations to help stakeholders prepare for the discussions. For each workshop, ARB also invited stakeholders to participate and provide comments on the development of proposed amendments. Staff announced all workshops and public meetings using the Cap-and-Trade (capandtrade) list serve. Workshop information and materials are posted on ARB's Cap-and-Trade Workshops and Meetings webpage: http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm

ARB accepted public comments on the draft proposed regulatory amendments presented at the July 18, 2013 workshop that are the basis for the proposed amendments discussed in this Staff Report until August 9, 2013. ARB received more than 75 written comments on the discussion draft amendments and met regularly with stakeholders to discuss concerns and recommendations. ARB also considered other comments provided to ARB outside of workshops.

As discussed in detail in Chapter II of this Staff Report, Summary of Proposed Action, the proposed amendments provide additional process for clarity in implementation, address stakeholder concerns on cost containment, extend the transition assistance for covered entities in the program and allow ARB to better oversee and implement the Regulation. In a separate rulemaking action, ARB's Mandatory Reporting Regulation is being amended to support some of the proposed changes to the Cap-and-Trade Program.

II. SUMMARY OF PROPOSED ACTION

This chapter summarizes the proposed amendments to the Cap-and-Trade Regulation to include changes resulting from board direction and stakeholder feedback to implement and oversee the Regulation. In general, staff proposed amendments to the Regulation including those related to allocation, covered and exempt emissions, electricity, offset program implementation, market program implementation, and cost containment.

For purposes of allocation, staff proposed allocation for new sectors (i.e., legacy contract generators, universities and district heating facilities, combined heat and power and public service facilities, and natural gas suppliers) and amendments that will shift the scheduled reduction in allowance allocation assistance factors by one compliance period. This shift is intended to provide additional time and certainty to industry to make necessary investments in efficiency and emission reducing technologies.

Staff proposed several modifications to covered and exempt emissions to maintain consistency with the Mandatory Reporting Regulation, recognize existing broad-based GHG reduction programs by the military, ensure correct incentives for combined heat and power, and allow time for more information on GHG abatement potential between the various waste treatment streams

Proposed amendments to the electricity sector include modification to resource shuffling provisions, renewable energy credits and imported electricity. The resource shuffling modifications define several activities, colloquially known as "safe harbors", that will not be considered resource shuffling and remove an attestation requirement that was could potentially negatively impact the western electricity markets.

Staff proposed clarifications and new provisions to help implement the offset program. Staff evaluated and clarified processes related to offset program implementation, including project listing requirements, monitoring and reporting requirements, verification body requirements, conflict of interest requirements, compliance offset credit issuance, timing and deadlines, and roles of air quality districts. Staff also proposed changes to clarify the invalidation requirements to be consistent for all project types.

Proposed amendments for market provisions relate to implementation, auctions and reserve sales, additional information reporting, cost containment, and enhancements to support market oversight. Staff proposed modifications related to the implementation of the auction and trading provisions within the Auction Platform and Compliance Information Tracking Services System (CITSS), and modifications to the current schedule for auctions and reserve sales. Staff proposed modifications to the existing information disclosure requirements and new requirements to ensure rigorous oversight

of the market program and of actions taken in the tracking system. Staff proposed additional information disclosure requirements to help ARB monitor relationships between consultants and market participants. Collectively, amendments relating to market provisions will help ARB to monitor the market and provide public reports for program transparency.

The sections below provide additional summary information for all proposed amendments to the Regulation as well as an expanded discussion of staff's rationale for these changes. These changes are discussed by major topic area: allowance allocation, covered and exempt emissions, electricity, offsets and offset program implementation, market implementation, and cost containment.

A. Allowance Allocation

Allocation is the process ARB uses to distribute the allowances it issues. Allowances can be sold, freely allocated based on specific criteria contained in the R, or some combination of the two. Freely allocated allowances are distributed to covered entities to prevent both production and emissions leakage, provide transitional assistance to a lower-carbon economy, reward early action to reduce emissions, and, in the case of electricity distribution utilities and natural gas suppliers, on behalf of ratepayers. This section describes the changes made to allowance allocation.

1. Allocation to New Entrant Industrial Facilities

Staff proposed amendments to the allocation methodology for new industrial facilities. New entrant facilities are defined either as facilities, whose emissions first exceeded the cap-and-trade threshold in 2012, or facilities that opted into the program for calendar year 2012 or subsequent years. Staff proposed allowing facilities with a NAICS code associated with a leakage risk classification to be eligible for direct allocation.

Staff proposed amending the Regulation to allow new facilities to be eligible for direct allocation if the first three digits of the facility's NAICS code matches the NAICS code of a sector already included in the current leakage analysis. The leakage analysis was initially only performed for industrial sectors with facilities above the cap-and-trade threshold at the time of analysis. Thus, the absence of a leakage risk for new sectors does not reflect their leakage risk classification but a lack of information on the sector at the time the original Regulation was developed. The proposal to match the first three digits of the NAICS code was chosen based on a review of the NAICS codes and the similarity of activities with matching three digits.

New entrants that match the first three digits of included NAICS codes will be allocated under a low leakage risk classification. Staff chose to apply the low leakage risk as a

conservative estimate in initial allocation. Since the true-up allocation corrects the allowance distribution provided to the entity two years prior to true-up, staff will have two years to perform the leakage analysis and update leakage risk classification. The true-up will then correct the historical allocation using the updated leakage risk classification.

New entrant industrial facilities that are eligible to receive direct allocation are allocated under the product-based allocation methodology if the facility performs an activity that has been assigned a product benchmark. New entrant industrial facilities that are eligible to receive direct allocation but do not have a product benchmark are allocated allowances using the energy-based allocation methodology.

Staff proposed modifications to the Regulation to define how to apply the energy-based allocation methodology for new entrants. The proposed methodology uses a three-part approach to allocation that is based on data reported through the Mandatory Reporting Regulation.

For an opt-in covered entity with no historical energy data to report, staff proposed using a *preliminary allocation* based on engineering estimates. The true-up mechanism described in the next section will account for any differences between engineering estimates and actual emissions.

For facilities with historical emissions reported through MRR, Staff proposed using a *transitional allocation* or *stable allocation*, based on the change in that facility's emissions from the previous year. The stability factor compares the previous year's emissions to the average historical emissions of the last two years reported through MRR. If the percent change is greater than 10 percent, the facility will receive a *transitional allocation*. If the percent change is less than 10 percent, the facility will receive a *stable allocation*. If the stability equation calls for emissions data in years that were not reported through MRR, the value of those emissions is zero. Facilities transitioning from the *preliminary allocation* will have a stability factor greater than 10 percent, and therefore will receive *transitional allocation* since historical emissions prior to MRR are considered zero.

For facilities with historical annual energy usage data, Staff proposed a *transitional allocation* that would be based on this data. This allocation methodology will change with changing fuel usage, and thus allocation can be updated to account for changing energy use at the facility level. Staff proposed this methodology because new entrant industrial facilities may take several years to reach full capacity. This allocation includes a true-up to correct the historical allocation based on actual energy usage in the allocation vintage year. This ensures that any discrepancies in the allocation for facilities that were previously under the preliminary allocation methodology are corrected.

For new entrant industrial facilities that have a three-year historical average annual energy usage, staff proposed the *stable allocation* under the energy-based methodology. Unlike the transitional allocation, this methodology is non-updating and will not change with changing energy usage. Staff is willing to work with facilities that do expand after reaching stable allocation in order to develop product benchmarks. This methodology will enable facilities to move to the product-based allocation methodology, which will increase or decrease based on the total amount of annual production.

2. Opt-in Covered Entities

The existing Regulation includes provisions for entities that do not meet the cap-and-trade threshold requirements but choose to voluntarily participate in the Cap-and-Trade Program. These entities are referred to as "opt-in covered entities." Staff included provisions for these entities to be eligible to receive free allowances similar to covered entities.

Staff proposed modifications to change the opt-in date from November 1 to March 1 of the year prior to the opt-in year to allow these facilities to report through MRR to be eligible for allowances in the opt-in year. Staff also proposed allowing opt-in entities to rescind their opt-in application prior to receiving their first allocation. This allows a facility opting in to go through the full reporting and verification to understand its compliance costs and use this information to update its decision to opt into the program.

3. Facility Closure

The possibility exists that the operator of an eligible facility could receive a direct allocation of allowances, but shut down operations prior to a surrender obligation for that compliance period. For example, a facility that was in the program as of 2012 is eligible to receive allocation of vintage 2013 allowances in November 2012. If that facility closes permanently in early in 2013, the facility will have a compliance obligation much lower than the allocation it received.

Thus, staff proposed an additional provision in the Regulation to address entities that have received a direct allocation of allowances but either shut down or cease operations prior to incurring a surrender obligation in that compliance period. Staff proposed that within 30 days of facility closure, the facility operator must inform ARB in writing to either close its CITSS account, or remain in the program as a VAE. Staff proposed two options for these entities: to either fulfill the prorated compliance obligation for that compliance period, or surrender all allowances equivalent to the direct allocation less any allowances that were used to satisfy a surrender obligation. Lastly, staff proposed that any allowances left in the entity's CITSS account after account closure will be consigned to auction on behalf of the entity.

Staff's rationale is that direct allocation is provided for transition assistance and to minimize leakage and assists in meeting a surrender obligation in the compliance period for which the allocation was received. Thus, if a facility receives allocation but has a greatly reduced compliance obligation, staff believes that the direct allocation, minus any allowances used for a surrender obligation, should be returned to the State of California. Any additional allowances beyond the direct allocation that were purchased by the entity and left in a CITSS account upon account closure would be consigned to auction on behalf of the entity.

4. True-Up Allocations

The existing Regulation defines a true-up for product-based allocation and first compliance period refinery allocation. Since free allocation occurs in the calendar year prior to the allowance vintage being distributed, and production reporting occurs in the calendar year after the emissions occur, a discrepancy of two years is created between production and allocation. The allocation distributed is based production data from two years prior, which serves as proxy data; the actual production will not be available to inform allocation calculations until two years subsequent to allocation. The purpose of the true-up is to correct this proxy of production with the actual production data. The true-up calculation does this by taking the difference of the actual production and the proxy production, and multiplying this value by the current benchmark, historical cap adjustment factor, and historical assistance factor. The difference in the two production values represents the true-up term.

Staff proposed modifications to the true-up equation to account for changes in product benchmark, allocation methodology, cap adjustment factor, or assistance factor. This was achieved in the proposal by taking the difference of historical allocation based on the proxy production, and what the actual allocation should have been based on actual production, benchmark, and other factors. Since historical allocation could have been under the energy-based allocation, this expansion of the true-up corrects changes in this methodology as well.

Staff proposed to expand the use of true-up allowances to other allocation methodologies including refinery allocation, new entrant energy-based allocation, university allocation, and legacy contract allocation. The function of the true-up remains the same as with product-based allocation: to correct the historical proxy allocation and base the revised allocation on actual data reported through mandatory reporting.

Staff also proposed to allow limited borrowing by allowing 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. For example, facilities will be able to use up to the amount of 2015 vintage allowances calculated in the true-up for the 2013

compliance obligations. This proposal links the allocation corrected in the true-up to the compliance obligation. In the example above, the 2015 true-up corrects the 2013 allocation. By allowing the 2015 true-up to be used for 2013 compliance obligation, actual production and compliance obligation are linked and provide the most up-to-date incentives in both reducing leakage and meeting a facility's compliance obligation. This true-up allowance amount can only be used for earlier years by the trued-up entity.

5. Natural Gas Suppliers

Natural gas suppliers will be covered starting in the second compliance period throughout the duration of the program. The suppliers will have a compliance obligation for all delivered natural gas minus any 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 mainly from residential and commercial uses and small industrial facilities.

Staff proposed changes to give the natural gas suppliers free allocations based on the entities' 2011 covered greenhouse gas emissions and the cap decline factor. Of the natural gas consumed in California, nearly all is delivered by investor-owned natural gas utilities – defined in statute as public utility gas corporations. Under the proposed changes, these utilities will be required to consign a portion of their allocated allowances to auction, starting at 25% in 2015 and increasing by 5% per year to 50% in 2020 with an ultimate goal of 100% consignment by 2030.

ARB proposed a long term goal of 100% consignment to encourage efficiency and conservation to reduce emissions in this sector. This transitional approach allows for a price signal to end users while allowing them time to convert to lower carbon alternatives. Natural Gas is used for many basic household tasks such as heating and cooking. Myriad emissions reduction opportunities are available for end users in this sector and experts have estimated that a price signal would result in significant corresponding reductions (Fuller 2010, Alberini 2011, Costello 2006, Navigant 2012). For example, at $15/allowance and full cost pass through, based on elasticities used by the American Gas Association and the California Energy Commission, residential natural gas use, and associated GHG emissions, would decrease by about 1.5%-2% in a given year (Joutz and Trost 2007, Medlock 2013).

During the consignment phase-in, the CPUC may direct the utilities to use the funds from consignment for the benefit of these ratepayers.

Table 1: Percent of allowances distributed to public utility gas corporations to be consigned to auction

Year	2013	2014	2015	2016	2017	2018	2019	2020
Percent Consigned	0%	0%	25%	30%	35%	40%	45%	50%

6. Legacy Contracts

The proposed changes include a limited-term allowance allocation to the operators of generators that have a contract with a third party that was entered into before September 1, 2006 (legacy contract generators). Legacy contract generators are defined as operators of generators under a contract to provide useful thermal output and/or electricity to a counterparty, where the contract does not contain a provision for reasonably recovering costs associated with the generator's Cap-and-Trade compliance obligation. The design of the Program is to encourage emissions reduction through an economic incentive. The legacy contract set-up does not send the appropriate incentive because the cost of compliance cannot be reasonably passed through to the purchaser to encourage reductions. Per Resolution 12-33, the Board directed staff to proposed changes to the Regulation to include appropriate transition assistance for these legacy contracts. While ARB's preferred approach to resolving the situation is for the parties to renegotiate the contracts, ARB recognizes that renegotiation takes time.

This proposal provides for an allowance allocation to the operators of legacy contract generators for two purposes: 1) to correct incentives in the case of those generators with an industrial counterparty by adjusting the counterparty allocation and providing those allowances to the legacy contract generator or 2) to provide transitional assistance.

For industrial covered entities, the purpose of allocation was to minimize leakage associated with GHG costs. Since emissions associated with a legacy contract do not have a GHG costs from the perspective of the steam or electricity purchaser, no allowances should be allocated to the industrial facility for those related emissions. By 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.

The second purpose for allocation is for transitional assistance and is limited to the first compliance period. This allocation approach maintains the incentive for legacy contract generators to renegotiate while providing appropriate transition assistance for these generators in accordance with Board Resolution 12-33. This approach also appropriately recognizes 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. For ARB to provide a full allocation for the entire contract period for all legacy contract generators for the full length of these private contracts would have the perverse result that those who renegotiated could have received less favorable treatment than those who did not renegotiate.

Furthermore, ARB is not in a position to have full knowledge of the original negotiation and how GHG costs were discussed during these contract negotiations. In comments that ARB received, there was apparent disagreement during the various discussions among parties as to how to consider the inclusion of such costs. It is not appropriate for ARB to interject itself into the interactions between parties in private contract discussions where ARB cannot possibly know what both sides intended when they executed the contract.

Furthermore, allowance allocation for the entire length of a legacy contract for generators whose counterparties are not industrial entities does not accomplish the intended goal of the Program to encouraging efficiency in the use of energy by the entity that makes decisions about how to use that energy. ARB 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, consistent with the Program goals.

7. Universities and Public Service Facilities

Board Resolution 12-33 directed staff to develop a methodology to provide transitional assistance to universities that are covered entities. The Board recognized that universities have taken early action to reduce their GHG emissions by investing in energy efficiency, combined heat and power, lower carbon energy sources and renewable energy on their campuses. In addition, universities have provided leadership in the research and development of technologies to reduce emissions and increase efficiency throughout the economy. To recognize these actions and ensure a smooth transition into the Cap-and-Trade Program, staff proposed to provide transition assistance to universities in a manner similar to the approach taken in the industrial sector.

The university allocation methodology would be consistent with ARB's allocation approach for industrial sectors. The approach would use a modified version of the

energy-based calculation methodology used for industrial sectors in which a product-based allocation methodology was not initially feasible. Allocations would decline in proportion to the cap, similar to all other allocation processes in the Regulation.

Based on stakeholder input, staff recognized that there are a few covered entities owned by municipalities that provide thermal energy to municipally-owned buildings that, like universities, have made investments to reduce emissions. Staff propose to extend transition assistance to these public service facilities on the same basis as to universities.

University campuses and public service facilities that receive allowances would be encouraged to use their allocated allowance value in ways that will further reduce GHG emissions. This could include investments in improving campus GHG efficiency, or further research and development in GHG-reducing technologies and strategies. These entities would be required to report to ARB on the use of the allowance value associated with their allocations.

8. Electrical Distribution Utilities

Staff proposed several small changes to Table 9-3, which enumerates allocations to account for new information regarding specific Electrical Distribution Utilities (EDUs). There are minor changes to names and classification of three EDUs in Table 9-3. Two of these changes reflect change in ownership of an EDU, while the third corrects the classification from POU to IOU for one EDU.

Additionally, 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. The allocation to Anza Electric Cooperative was increased because imported electricity serving Anza's ratepayers has greater emissions than staff used to calculate their allocation in the original regulation. The allocation to Surprise Valley Electrical Corporation was reduced because emissions from their electricity imports are significantly lower than what was assumed based on previous information. No change was made to the overall allocation to the electricity sector.

9. Refinery Allocation

In the adopted Regulation, the refinery allocation methodology is set to change to the carbon weighted tonne (CWT) approach in the second compliance period. The current benchmarks for this approach are based on the EU ETS technologies and methodologies. Staff is considering several changes to this approach and is analyzing a possible change to a complexity weighted barrel (CWB). The CWB factors would be tailored to California specific needs and would be based on measurements common to

U.S. facilities, eliminating the need for additional measurements that could introduce both measurement errors and safety concerns. Both the CWB and CWT approaches define a factor for each process unit, relying on a proprietary methodology by Solomon Associates. The factors are multiplied by throughput and added to determine a carbon weighted barrel value for each refinery. This approach is designed to gauge the GHG efficiency of each process unit. The configuration differences and differences in inputs would be minimized with these approaches. Industries which are closely related to the refining sector such as coke calcining and hydrogen production, have allocation methodologies and benchmarks that are also being reconsidered. Similarly, allocation for liquified hydrogen production may also be adjusted. Any change to these methodologies will occur in coordination with the refinery allocation to maintain consistent incentives across related industries and to avoid double-counting.

Finally, staff proposes revisions to the refinery allocation true-up for consistency. We added a true up to refineries without EII values to account for changes in production or significant changes in emissions. This change corrects an inadvertent error in not providing a true-up to this group as occurs for every other sector receiving industrial allocations.

10. Other Product Based Benchmarks

The proposed Regulation amendment includes the addition of new sectors subject to a product-based benchmark. Resolution 11-32 directs staff to identify and propose new benchmarks for manufacturing of new products in California. The proposed amendments also include the modification of benchmark units and/or values for existing product-based benchmarks.

Staff proposed to add lead acid battery recyclers as a new sector under product-based benchmark to ensure that industry assistance is provided to these new entrants to the Cap-and-Trade Program. Staff also proposed to develop the new benchmarks for several sectors previously receiving allocation under the energy-based allocation methodology. With the development of these benchmarks, sectors will receive allocation based on the recent production level rather than the existing energy-based allocation that uses a historical average of energy consumption. This allows allocation to change with production to minimize emissions leakage that could result if production were to shift out of California.

Staff proposed a number of new product benchmarks in the food processing and beverage manufacturing sectors. These sectors include dairy processors, poultry, dehydrated flavors, snack chips, sugar, tomato, pistachios and almonds, beers, wine and spirits. Since a food or beverage facility commonly produces several different products that rely on complex process configurations, staff worked with industry and

contract experts since early 2012 to obtain the engineering expertise needed to establish technically sound product-based benchmarks. The key focus of the research has been to establish a methodology that apportions the energy consumed at a facility among various individual processes and evaluating the associated outputs by combining direct energy consumption measurements with engineering estimates.

Other sectors where staff proposed newly developed benchmarks include iron foundry, aluminum billets manufacturing, lead acid battery recycling, metal forging, onshore natural gas processing, and diatomaceous earth processing. These sectors produce fewer individual products at a facility or produce more homogeneous products compared with food processors. Staff believes that the data collected from participating facilities are sufficient to establish technically sound product-based benchmarks.

Staff also proposed to modify existing product-based benchmarks for thermal enhanced oil recovery and non-thermal crude petroleum and natural gas extraction, natural gas liquid extraction, tissue manufacturing, recycled boxboard manufacturing, flat glass manufacturing, container glass manufacturing, cement manufacturing, gypsum product manufacturing and steel cold rolling.

The reasons for these changes included new information on differences in products, inclusion or exclusion of base-years to obtain a reasonable set of representative years of operation, or the collection of more detailed data for sectors where limited initial data were available when the Regulation was adopted. The tissue sector benchmark considered the difference in water absorption capability by adding an equivalency factor. For the details, please see Appendix C.

11. Allocation to Public Wholesale Water Entities

In Resolution 11-32, the Board found that water rates should create the appropriate incentives for water conservation, greenhouse gas efficient technologies, and the efficient supply and use of water. The Board also found that if allowance value is used for the benefit of water ratepayers it should be used in a manner consistent with State efforts to promote efficient use and supply of water and water conservation. The Board directed the Executive Officer to continue discussions with stakeholders to identify and propose, as necessary, potential amendments to the regulation that could include 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. Following extensive discussions with affected stakeholders, staff believes that it is appropriate to allocate allowances to the Metropolitan Water District (MWD), a public wholesale water agency that obtains and conveys water resources to retail governmental water agencies and has a direct compliance obligation. Staff

believes that MWD is the only public water agency that will have a continuing compliance obligation during the period covered by the regulation.

Obtaining scarce water resources and conveying them to retail water purveyors is critical to the health and welfare of all citizens of the State. MWD imports electricity for the sole purpose of conveying water through its conveyance systems. Since the compliance costs associated with water conveyance are not borne by retail electric customers, the allocation of free allowances to electric distribution utilities (EDU) does not mitigate AB 32-related rate impacts on retail water customers.

Staff proposes to allocate allowances to MWD in a manner similar to the allocation to EDUs, in which the allocation amount is based primarily on the compliance cost burden on ratepayers. Staff proposes that the cost burden would be calculated based on resource types use to meet MWD's load, assuming that MWD would increase its procurement of renewable electricity to meet a significant portion of its load requirements by 2020. This is consistent with the approach used to allocate allowances to electrical distribution utilities (EDUs) represented in Table 9-3 of the Regulation.

To calculate the allowance allocation, staff used historical data provided by MWD on electricity procured from different resource types. For consistency, staff used emission factors based on the assumptions used in allocation to EDUs, and included the same proportional credit for energy efficiency. Staff assumed that MWD would procure renewable electricity to meet a portion of their total load consistent with Renewable Portfolio Standard (RPS) requirements on EDUs, and that MWD would import unspecified electricity to meet any remaining load not met by specific resources. As an importer, MWD has a compliance obligation for this unspecified electricity. Finally, the allocation is reduced by the amount of the cap decline, as are all other allocations. Table 2 shows the assumptions used in calculating the allocation.

Because the public wholesale water entity did not receive allocations for 2013 and 2014, staff proposed to provide allowances from the 2015 budget year for emissions from 2013 -2014 as well as 2015. Allowances would be placed into the compliance accounts of the eligible agency. Using these allowances for compliance would allow the benefit to be passed through to customers. Because MWD is assumed to add significant renewable resources to their portfolio, consistent with RPS requirements on EDUs, the allocation will cover only part of the agency's forecast compliance obligation. This means that an increasing portion of compliance costs would be passed through to customers over time. Staff believes this is appropriate for transition assistance, and is consistent with maintaining a price signal in water rates to encourage efficiency and conservation.

Table 2: Calculation of Allocations to Public Wholesale Water Entities

Metropolitan Water District - Data Supplied to ARB

Year	2013	2014	2015	2016	2017	2018	2019	2020
MWD Imported Energy Average 2008-2012 (MWh)	325,012	325,012	325,012	325,012	325,012	325,012	325,012	325,012
5% loss of Hoover Energy - Starting 2018 (MWh)	0	0	0	0	0	54,223	54,223	54,223
Total Projected average Imported Energy (MWh)	325,012	325,012	325,012	325,012	325,012	379,235	379,235	379,235
Aggregated from data supplied by MWD for federal hydropower and contracts with Southern California Edison.								
MWD Hydroelectric	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	168,937	168,937	168,937	168,937	168,937	223,160	223,160	223,160

ARB Calculation of Cost Burden

MWD Total	1,795,257	1,795,257	1,795,257	1,795,257	1,795,257	1,795,257	1,795,257	1,795,257
RPS requirement applied to all EDUs	21.0%	22.0%	23.0%	25.0%	26.0%	29.0%	31.0%	33.0%
RPS Requirement (MWh)	377,004	394,957	412,909	448,814	466,767	520,625	556,530	592,435
Residual Natural Gas after RPS (MWh)	116,945	98,992	81,040	45,135	27,182	27,548	0	0
Natural Gas and Market Energy Emission Factor	0.4354	0.4354	0.4354	0.4354	0.4354	0.4354	0.4354	0.4354
Cap Decline Factor	0.981	0.963	0.944	0.925	0.907	0.888	0.869	0.851
Energy Efficiency credit	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908
Emissions for Cost Burden	49,950	41,507	33,309	18,178	10,734	10,651	0	0
Allocation to MWD			**136,491**	**22,086**	**14,643**	**14,559**	**3,908**	**3,908**

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B. Leakage

1. Changes to the Industrial Assistance Factor

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. The assistance factor for the third compliance period will be 100% for high, 75% for medium, and 50% for low leakage risk classification, but will be further evaluated and may be adjusted based on work underway. 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. In addition, staff is awaiting new research results that will improve the data, measurement, and metrics of the leakage risk 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. This research will inform ARB's evaluation of leakage risk factors for the third compliance period. Any changes to the leakage risk classification or assistance factors for the third compliance period would be proposed in subsequent rulemakings.

2. Leakage Risk Classifications

Staff proposed adding leakage risk classifications for new entrants in the industrial sector. These changes are necessary to allow these new entrants to receive appropriate allocations, pursuant to Board Resolutions 12-33 and 11-32. Details of the leakage analysis for these sectors can be found in Appendix B.

The new industrial sectors include:

- All Other Metal Ore Mining
- Asphalt Paving Mixture and Block Manufacturing
- Ethyl Alcohol Manufacturing
- Hardware manufacturing
- Guided Missile and Space Vehicle Manufacturing
- Nonferrous Forging

Staff also proposed changing the leakage risk classification for the mineral wool manufacturing sector from medium to high. This change is necessary to account for new data available which results in a greater risk of emissions leakage than staff

previously determined with a more limited dataset. Details of the updated leakage analysis for this sector can be found in Appendix B.

C. Covered Sectors and Exempt Emissions

1. New Sectors

Process emissions from lead facilities were not included in the previous GHG reporting regulations under MRR. As a result, certain lead producers did not exceed the Cap-and-Trade emissions threshold for coverage under the Program. MRR was updated to require California facilities producing lead to report their process CO_2 emissions in addition to combustion emissions. Reporting of both product and emissions data for the lead production sector is necessary to support the product-based methodology of allowance allocation.

The adopted GHG reporting regulation did not previously include emissions from liquefied natural gas suppliers. MRR was updated to require importers of liquefied natural gas and certain instate producers of liquefied natural gas to report the emissions that would result from the complete combustion of the liquefied natural gas sold in California. The update to the MRR provides equitable reporting of combustion emissions for all fuel suppliers. Staff proposed modifications to the Cap-and-Trade Regulation to include liquefied natural gas fuel suppliers as a covered entity to ensure equitable consideration of GHG emissions for all fuel types starting in the second compliance period.

2. Exempt Emissions

Staff proposed exempting a limited number of smaller combined heat and power (CHP) and district heating facilities and waste to energy emissions from a compliance obligation for the first compliance period only. Staff also proposed to remove the sunset date for the military exemption. The following sections outline the proposals in more detail.

Staff made the proposed changes to several sections of the Regulation to clarify the eligibility of biomass-derived fuels to avoid a compliance obligation. Change was made to correct this issue that prevented new biomass-derived fuel from being eligible and to close a loophole that could have allowed for emissions leakage.

Combined Heat and Power and District Heating

A few facilities 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. If these facilities are covered entities with a compliance obligation, they would face greenhouse gas costs during the first compliance period that are not faced by similar small industrial facilities without CHP. Small facilities without CHP can remain below the compliance threshold because they have no direct emissions due to electricity consumption, and their emissions from boilers that generate steam would be below the threshold for a covered entity. Under the current Cap-and-Trade Regulation, small facilities that made the efficient, lower emission, choice to install CHP would face higher GHG costs during the first compliance period than would similar facilities without CHP.

During subsequent compliance periods, natural gas prices will include compliance costs that are expected to be passed through by natural gas utilities. This means that after the first compliance period similar facilities with and without CHP will face compliance costs, either directly or indirectly through natural gas prices.

To reward "but for" facilities that reduced emissions by installing CHP, the Board directed staff in Resolution 12-33 to develop a methodology to exempt their thermal energy emissions during the first compliance period. Staff proposed a limited exemption for these emissions during the first compliance period, and as a result, these facilities will fall below the threshold and will not have a compliance obligation. The compliance obligation would be phased in for these facilities beginning with the second compliance period when the steam emissions are no longer exempt.

Staff proposed a similar exemption for steam emissions from district heating facilities that produce hot water, steam, or chilled water distributed to buildings that are not part of the same facility. District heating is a more efficient means of providing these services than the more common practice of installing water heaters, boilers and chillers in each building to provide these services. Because it serves multiple buildings, a district heating facility may have emissions above the threshold and face a compliance obligation not incurred by buildings with their own boilers and chillers that are less efficient. Like "but for" facilities, district heating facilities will not have this disadvantage once natural gas prices include GHG costs beginning with the second compliance period.

Facilities would be required to apply for the exemption of emissions and would need to provide data on emissions associated with qualified thermal output from "but for" cogeneration facilities and emissions associated with district heating services to each building. To preserve the environmental integrity of the cap, ARB would retire

allowances equivalent to the emissions that no longer had a compliance obligation after the limited exemption for thermal energy emissions.

Waste-Energy Emissions

The implementation of the Board direction in Resolution 12-33 to exempt Waste-to-Energy facilities in the first compliance period will be achieved by requiring the eligible operator to participate in the program by reporting and verifying their emissions. The Executive Officer will then place allowances into their compliance account and will retire allowances on behalf of the entity to meet the compliance requirements. This exemption will apply only during the first compliance period to allow for the completion of the interagency study that will determine the best approach to treat Municipal Solid Waste under the Cap-and-Trade program.

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. The eligibility requirements require the facilities to operate under an existing air permit, and the fuel must be derived from Municipal Solid Waste. The requirement to operate under an existing permit and the requirement to limit the fuel combusted to Municipal Solid Waste will limit the ability for new facilities to seek an exemption from the Cap-and-Trade program until the study which will determine the best approach to treat solid waste under Cap-and-Trade is complete.

Military Exemption

Section 95852.2 was modified to remove the exemption sunset date for military facilities. Staff believes it is appropriate to exempt military facilities as this sector cannot respond to the price signal. In addition, this sector has other mechanisms already in place that have the potential to achieve equivalent reductions through a broad-based approach that encompasses sources that are below applicability thresholds for both the Mandatory Reporting Regulation and the Cap-and-Trade Program. The military sector is also subject to Presidential Executive Order 13514 Strategic Sustainability Performance Plan (Sustainability Plan) that includes a 34 percent reduction in Scope 1 and Scope 2 GHG emissions, 13.5 percent reduction in Scope 3 GHG emissions, a 37.5 percent reduction in building energy intensity, a 20 percent renewable energy standard, and a 30 percent reduction in fossil fuel consumption for vehicle fleets.

D. Electricity

1. Resource Shuffling

In adopting Regulations to reduce greenhouse gas (GHG) emissions, Assembly Bill 32 requires the Air Resources Board (ARB) to minimize leakage to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit. This requirement is mandated in section 38562 of Division 25.5 of the Health and Safety Code. As defined by section 38505, leakage means a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.

Resource shuffling is a form of leakage that could occur in the electricity sector. To minimize leakage related to the delivery of electricity in California, the Cap-and-Trade Regulation currently defines and prohibits resource shuffling.

In Resolution 12-51, the Board 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 would not consider resource shuffling based on Attachment A of Resolution 12-51. Staff was further directed to return to the Board with proposed regulatory amendments by mid-2013, and to publish regulatory guidance consistent with Attachment A prior to the November 14, 2012 allowance auction.

Staff proposed modifications to the definition of resource shuffling and changes to clarify certain activities that constitute resource shuffling, and certain activities that are not resource shuffling. These clarifications are consistent with the intent of Attachment A, and with the previously published guidance.

First, staff proposed to change the definition to clarify that resource shuffling is a plan, scheme, or artifice undertaken by a First Deliverer of electricity to substitute electricity from relatively lower emissions resources with electricity from higher emissions resources in order to reduce its emissions compliance obligation. Resource 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.

However, 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. Therefore, staff modified section 95852(b)(4) to list thirteen activities that are considered

"safe harbors" and are not resource shuffling. Safe harbors include activities in the following categories:

- Situations in which First Deliverers are required to make or accept certain electricity deliveries.
- Situations in which First Deliverers deliver lower emission electricity replacing higher emission electricity due to circumstances beyond their control.
- Situations in which a First Deliverer has a more than enough electricity to meet demand and therefore cuts back on electricity from high emission resources.
- Short term transactions in electricity markets that are not linked to other resource shuffling activities, or entered into in order to reduce compliance obligations.

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.

Finally, staff considered stakeholder comments and input from the Commissioner Moeller of the Federal Energy Regulatory Commission regarding the potential of the required attestations concerning resource shuffling to negatively affect western electricity markets (Moeller 2012). As a result, staff proposed to remove the regulatory language that requires such attestations.

2. Voluntary Renewable Energy (VRE)

Staff proposed modifications to clarify that RECs created for voluntary renewable energy (VRE) must represent the same generation included in the information submitted to ARB in the allowance retirement request, and those same RECs must be retired before the allowance retirement request is submitted to ARB.

The modifications also clarify the electricity must be directly delivered to California. This was already stated in the Regulation under the first paragraph but the requirement is now added to the list of eligibility requirements.

The additional language also clarifies that RECs created on the last day and hour of the budget year for which allowance retirement is requested are eligible for the voluntary renewable energy program. It is recognized WREGIS may not generate the RECs until 90 days after generation. If a REC is created at 11:59 pm on December 31, 2013, it is eligible to be used for the program and the applicant needs to retired the REC before

the final application date of July 1 the following year. This time frame allows WREGIS to issue serial numbers and place the REC into the applicant's account, and for the applicant to move the REC to the compliance account for the purpose of retirement for California's Voluntary Renewable Electricity Program.

3. Imported Electricity

The proposal clarifies that Asset Controlling Suppliers are a specified source for purposes of the Regulation. Asset Controlling Suppliers are entities that apply annually, pursuant to MRR, and have a specific emission factor assigned to their electricity based on declared resources that serve California load. Importers that have a contract for electricity from an Asset Controlling Supplier are able to apply that specific emission factor to electricity delivered to California. The section on specified sources is also modified to clarify that there are specified resources that generate electricity, which is imported into California, and these resources could have emission factors which exceed the default emissions factor. Modifications were made so that requirements to the point of Regulation for imported electricity and electricity generated in-state are consistent. The serial numbers of the RECs will be reported and published on the MRR website, rather than requiring the importer to retire the REC. Programs in other states that want to ensure that RECs used in their program have not been used in California's program will be able to check the MRR website for REC retirement pursuant to California's program. The purpose of this process is to recognize that the electricity associated with the REC was already reported to California by the importer as zero emissions electricity, pursuant to MRR.

Staff proposed to clarify the adjustment to the compliance obligation for electricity procured to meet an RPS requirement. Clarifications were made to clearly identify the section applies to electricity that is procured, but not able to be imported into California. The adjustment was made to the compliance obligation for replacement electricity is imported, but based on the procurement of the RPS eligible electricity that is not able to be delivered to California due to transmission limitations.

The proposal clarifies RECs must be from the same eligible renewable electricity generating facility as the electricity that is procured. The REC is the compliance instrument that is required by the Energy Commission used to meet the RPS requirement and the adjustment to the compliance obligation will be based on the MWh represented by the RECs and reported pursuant to MRR.

E. Offsets and Offset Program Implementation

1. New Offset Protocol

Under the Cap-and-Trade Program, covered entities may use compliance offset credits to satisfy up to eight percent of their compliance obligation. This limit applies to each individual covered or opt-in covered entity for each compliance period. Compliance offsets are tradable credits that represent verified greenhouse gas (GHG) emissions reductions or removal enhancements from sources not subject to a compliance obligation in the Cap-and-Trade Program. As an important market feature, offset credits can provide covered entities a source of low-cost emissions reductions for compliance flexibility. The inclusion of offset credits will also support the development of innovative projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California. Ensuring sufficient offset supply is consistent with the requirement in AB 32 to design a market program that is cost effective in reducing GHG emissions.

To date, ARB has approved four compliance offset protocols. Staff believes these four protocols, including early action offsets, will be sufficient to meet the eight percent maximum demand for compliance offsets for the first compliance period. In 2015, the scope of the program doubles when transportation fuels and upstream natural gas emissions are covered. The existing four protocols will not supply all of the offsets needed to ensure sufficient supply if every covered entity used up to the maximum offset usage limit of eight percent in offsets for compliance in the second and third compliance periods.

To address stakeholder concerns related to cost containment, staff developed an additional compliance offset protocol which can be found in Appendix A of the Staff Report, for use under the compliance offset program. Staff included the Mine Methane Capture Protocol. This protocol is incorporated by reference in the proposed regulation and is being considered for adoption by the Board as part of this rulemaking package.

2. Offset Program Implementation

Staff proposed clarifications to address APD requirements, including when an Offset Project Operator (OPO) may designate the APD and any other third party to receive ARB offset credits. In addition, staff proposed requirements that APDs must meet for CITSS registration, prior to listing an offset project.

Staff proposed clarifications to offset project listing requirements, including clarifying the timing requirements for submitting listing information and related attestations to an Offset Project Registry (OPR). In addition, staff clarified the administrative process for an OPR's review of listing information, and the timing for conducting their review. In addition, staff proposed to include procedures and requirements for transferring an offset project between OPRs.

Staff proposed to clarify the timing requirements for submitting the attestations associated with reporting to an OPR.

Staff proposed clarifications to the offset verification requirements, including: the verification timing requirements for offset projects, the rotation of verification body requirements, the timing requirements for submitting a Notice of Offset Verification Services, the requirements for modifying Offset Project Data Reports, the requirements for conducting data checks, and the offset material misstatement calculation.

Staff proposed clarifications to the conflict of interest requirements, including applying the conflict of interest requirements to both an OPO, and an APD, if applicable, and any subcontractors working as part of the offset verification team. Staff proposed to clarify the timing requirements for submitting conflict of interest self-evaluations and included a process and requirements for OPR approval of conflict of interest self-evaluations.

Staff proposed clarifications to the issuance, timing and deadlines associated with registry and ARB offset credits. Staff proposed clarifications to the process for OPRs to request additional information for the issuance of registry offset credits, and included a dispute resolution process with ARB if an OPR denies issuance of registry offset credits. Staff clarified the process for requesting issuance of ARB offset credits and the types of information that must be submitted to ARB with the issuance request. Staff also proposed clarifications including the timing for ARB notification to parties that are receiving ARB offset credits and the requirements that OPRs must meet when ARB issues ARB offset credits.

Staff proposed new language to modify the requirements for air districts for assessing conflict of interest.

Staff also proposed to clarify processes related to the early action program. These amendments address early action offset project listing requirements, early action verification requirements, Forest Buffer Account requirements, and issuance of ARB offset credits for purposes of early action.

Staff also proposed changes to make the liability in the event of invalidation consistent for all project types. These changes were made to the invalidation rules that govern ARB offset credits issued for both compliance offset projects and early action offset projects. Staff also proposed clarifications and additions to definitions, as required.

Staff also proposed to change forest offset invalidation to buyer liability to align with existing requirements for other offsets project types. The main circumstances that could lead to invalidation include identification of errors in reporting or verification, projects being out of regulatory conformance, or double crediting. The intent was always to have all invalidation requirements to be consistent across all project types to ensure that covered entities did their due diligence when purchasing compliance offsets to use for compliance. Under the current requirements, if a covered entity retires a forestry ARB offset credit and then it gets invalidated, the forest landowner is responsible and the covered entity is still considered to be in compliance even if it does not have enough valid compliance instruments. By aligning the invalidation requirements for forestry with the existing invalidation requirements for other project types, entities are required to have enough valid compliance instruments to be considered in compliance with the Regulation. The forest owner still maintains liability for intentional reversals (cutting trees or ending the project) and the forest buffer account will still compensate for unintentional reversals (fires, infestations).

F. Compliance Obligation Surrender

1. Compliance Instrument Retirement Order

The existing Regulation is silent on which order compliance instruments are retired from the covered or opt-in entity's compliance account by the Executive Officer at the time of the annual and triennial surrender events. The proposed amendments include a retirement order to implement this process in the Compliance Instrument Tracking System Service. 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.

2. Annual Obligation Surrender

Staff proposed compliance instruments not be retired at the time of the annual obligation surrender event and that compliance instruments only be retired during at the time of the triennial obligation surrender event. During workshops, stakeholders had expressed concerns that any offsets placed into their compliance account would all be retired first by the Executive Officer pursuant to the proposed compliance instrument retirement order. Stakeholders expressed concern that they may place offsets into their compliance account to comply with the annual surrender, but because there is no eight percent offset limit applied to the annual obligation surrender, the total amount of offsets in an account could exceed the eight percent limit at the time of the triennial obligation surrender. This may result in "lost" offsets since offsets retired during the annual obligation surrender that were in excess of the eight percent limit at the time of the triennial obligation surrender could not be transferred back to the entity's compliance account from ARB's retirement account. By not retiring any compliance instruments at the time of the annual obligation surrender event and only retiring compliance instruments at the triennial obligation surrender event, stakeholders' concerns regarding "lost" compliance offsets is no longer an issue. The instruments in the entity's compliance account would continue to count against their limited exemption to the holding limit until such time that compliance instruments are retired during the triennial compliance event.

G. Implementation of Auction and Trading Requirements

1. Corporate Association Disclosure

The existing Regulation already requires that a registered entity disclose its corporate associations. Many entities were under the impression that only other entities in the Cap-and-Trade Program are considered corporate associates. Staff proposed modifications to specify that corporate associations are not limited to relationships between entities registered in the program.

The existing Regulation does not address limited liability corporations, which may not have the criteria to measure ownership listed in the Regulation, such as listed shares. To close this loophole, staff proposed modifications to specify that ownership of limited liability corporations apply for purposes of determining whether a corporate association exists, regardless of how the interest is held.

A deadline date for opting-out of consolidated accounts is in the current Regulation. Staff proposed to eliminate that deadline. Instead, staff proposed a new clause allowing direct corporate associates to switch between consolidation and opting-out only once per year.

2. Registration

Staff proposed to modify the Regulation to clarify the requirements for registration in the cap-and-trade program. The changes are necessary for operations of the cap-and-trade program and to assist in market monitoring.

3. Bid Guarantees

Staff proposed changes to clarify the submission of bid guarantees by auction participants. Language was added to clearly state that if a single big guarantee is submitted to cover both Current and Advance Auctions then it must be greater than or equal to the combined maximum value of bids to be submitted. Staff proposed additional language to clearly identify that any bid guarantee submitted by an auction participant that does not cover the maximum value of the bids to be submitted is a violation of the Regulation.

4. Additional Information on Advisors, Contractors, and Individual Voluntarily Associated Entities

During the first 18 months of implementation of the Cap-and-Trade Program, staff has encountered several situations related to individuals who applied to register as a voluntarily associated entity, but have access to compliance accounts or compliance instruments in entity accounts. Some of these individuals work for a covered, opt-in, or other voluntarily associated entity, or a contractor that provides GHG related services to a covered, opt-in, or other voluntarily associated entity.

In the case of individuals that work for already registered market participants or contractors providing GHG related services to registered market participants, the proposed amendments would require the individual to provide a notarized letter from the employer indicating they are aware of the individual's request to register as a voluntarily

associated entity. This ensures that the existing registered market participant is aware of the potential of the individual using information garnered in their employment for personal gain and the employer has policies or procedures in place to mitigate that risk. By collecting this information, staff and the market monitor have a better understanding of the relationships between market participants that could lead to insider trading or collusive behavior.

Their already exists a requirement for market participants who employ a bid advisor to inform ARB of the bid advisor. However, due to contractual confidentiality requirements, the covered entity is not able to disclose other clients, who are market participants, using their same bid advisor. The proposed amendments require the bid advisor to disclose all market participants for whom they are providing auction bidding services. Having information on shared bid advisor resources between market participants will aid staff and the market monitor in monitoring for collusive behavior.

5. Transfer Reporting Requirements

Staff proposed modifications to the existing list of information that must be included in transfer requests submitted in the tracking system. In developing the changes, staff reviewed stakeholder comments on the regulation, transaction agreements that staff have obtained from account representatives, and transfer request information contained in CITSS. Staff concluded that while the existing system requires the appropriate information categories (agreement dates, settlement dates, termination dates, price, and quantity), the great variety of transaction agreements can make it difficult for account representatives to interpret the requirements for their type of transaction agreement. In ARB's proposal, the existing information categories have been expanded so that the account representative (1) identifies the type of transaction agreement being executed, and (2) provides the information specific to that type of transaction agreement. The additional detail will aid staff in understanding the market contracts to allow for better oversight of the program.

Staff has found it difficult to analyze price data for market monitoring purposes when staff does not know the type of transaction agreement involved. For example, the transaction agreement may provide for the transfer of other products in addition to compliance instruments. The cost terms of the agreement may not itemize a separate price for compliance instruments, may involve multiple transfers, or the price will reflect a negotiated package deal. Staff is proposing that the entity identify the other products specified in the agreement and if the agreement provides for multiple transfers.

Transactions also may contain varying methods of setting the price for the compliance instruments. If the price is a fixed value in the contract, the staff proposal keeps the current requirement that the entity simply enter that value. If the price is not a single fixed value, staff is proposing that the transfer request obtain more information on the pricing method. If the price is specified as a base plus a margin, staff proposed the entity enter the base and the margin. If the agreement uses some other method, staff proposed the entity enter a brief description of the method.

The staff proposal clarifies the process the accounts administrator and account representatives will follow in case a transfer request is found to be deficient. The changes address stakeholder concerns that account representatives could find out an entity's account balances by sending spurious transfer requests. Under the existing regulation, account representatives of both accounts would be informed of the deficiency. Staff is proposing a process that would prevent the account representative submitting a transfer request from gaining information about the receiving entity's account. In addition, the proposed changes would make filing a transfer request in the absence of an underlying transaction agreement a violation.

H. Cost Containment

1. Proposed Additional Cost Containment Mechanism

In October 2012, the Board adopted Resolution 12-51 directing staff to develop a proposal for one or more additional cost containment mechanisms to "achieve the policy objective of ensuring that the allowance prices will not exceed the highest price tier of the Allowance Price Containment Reserve while minimizing the impact on existing allowances and maintaining the environmental objectives of the program." Staff was also directed to "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."[2]

In response to the Board Resolution, staff developed a proposal for an additional cost containment mechanism that increases the availability of allowances at the highest price tier of the Allowance Price Containment Reserve (Reserve). Knowing that allowances will be available from the Reserve, compliance entities will have no incentive to purchase allowances at any price higher than the highest price tier. In this manner, maintaining the availability of a sufficient supply of allowances to satisfy demand at the

[2] Resolution 12-51. California Air Resources Board, October 2010. Available at: http://www.arb.ca.gov/cc/capandtrade/final-resolution-october-2012.pdf

Reserve sale will be effective in ensuring that allowances prices do not exceed the highest price tier.

Table 3 lists the allowances that the staff proposal makes eligible for sale at the Reserve top tier price. The allowances in the table are 10% of the allowances that remain in each budget year listed in Table 6-1 of the Cap-and-Trade Regulation after allowances have been removed to fill the three Reserve tiers. These 206.7 million allowances will be eligible for sale at the Reserve sales immediately preceding the compliance deadline on November 1 each year, and are first eligible for sale prior to the November 1, 2015 compliance deadline. The timing of these Reserve sales ensures that covered entities will know their compliance obligation and be able to purchase allowances for compliance prior to each November 1 compliance deadline.

Table 3: Allowances made eligible for reserve sale by the Staff Proposal

Budget Year	Allowances (Millions of CA GHG Allowances)
2015	37.9
2016	36.7
2017	35.6
2018	33.3
2019	32.2
2020	31.0
Total	**206.7**

For a given budget year, if fewer allowances remain in the Auction Holding Account than the quantity eligible for sale in Table 3, the amount available for sale will be reduced to the quantity that remains available. If, for instance, at the Reserve sale immediately preceding the compliance obligation on November 1, 2015, only 25 million budget year 2015 allowances remain in the Auction Holding Account, the number of 2015 allowances eligible for sale would be reduced to 25 million.

If needed to fill accepted bids at the highest price tier, the allowances listed in Table 3 will be sold beginning with the latest budget year (furthest in the future) and then the preceding budget years until either all accepted bids are filled or all eligible allowances are sold. Currently, 2020 is the budget year that is furthest in the future. If needed, allowances will first be sold from the 31 million eligible 2020 allowances, then the eligible 2019 allowances, continuing until all accepted highest price tier bids are filled or all eligible allowances are sold.

If allowances from a budget year are sold through this process, the number of allowances that are available for the advance auction for that budget year will be reduced by the number of allowances sold. If more allowances are sold through this process than remain available for advance auction, then the allowances for the current auction of the budget year will be reduced. If the quantity of accepted bids at the highest price tier exceeds the quantity of eligible allowances, purchases will be determined following the over-subscription procedure used in the Reserve sales.

Under the proposal, all allowances purchased from Reserve sales are eligible immediately for compliance on November 1. As is the case for all allowances purchased at a Reserve sale, these allowances must go directly into the purchasing entity's compliance account, and are subject to the program's allowance holding limits. In regards to instrument surrender, all allowances purchased from a Reserve sale are removed from an entity's compliance account after offset credits but prior to any allowances with a vintage year purchased outside of a Reserve sale.

2. Evaluation of Proposal

Board Resolution 12-51 directs staff to develop proposals that ensure that the allowance price does not exceed the highest price tier of the Reserve while maintaining the environmental integrity of the program over a reasonable range of plausible conditions.

The Cap-and-Trade Program is designed to reduce emissions cost effectively to achieve the AB 32 emissions goal. With the full range of program design features and compliance flexibility mechanisms, analyses supporting prior rulemakings indicated that allowance prices are expected to be in the range between the auction price floor and the Reserve prices for a broad range of future conditions.[3] However, unanticipated conditions could increase the demand for allowances, resulting in higher than expected allowance prices, including prices that could exceed the established Reserve prices. Higher than expected demand could be transitory, resulting from temporary imbalances in the supply and demand for allowances. Alternatively, unexpectedly high demand for

[3]Update Economic Analysis of California's Climate Change Scoping Plan. California Air Resources Board. March, 2010. Available at: http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf and Discussion Draft Economic Analysis Supporting the Cap-and-Trade Program. WCI Economic Modeling Team. May, 2012. Available at http://www.westernclimateinitiative.org/document-archives/Economic-Modeling-Team-Documents/Discussion-Draft-Economic-Analysis-Supporting-CA-and-QC-Linking/

allowances could be persistent, pushing allowance prices above expected levels for longer periods.

The quantity of allowances made eligible for the Reserve sale by the staff proposal is substantial. For example, without the staff proposal, the total number of allowances eligible for use at the November 1, 2015 compliance deadline would be about 319 million from the 2013 and 2014 budget years, and 121 million from the existing Reserve, for a total of about 440 million. The staff proposal makes eligible an additional 207 million, an increase of nearly 50%, bringing the total to about 647 million allowances. This figure does not include the offset credits that could also be used for compliance and covers cumulative emissions and compliance instruments available for use by the November 1, 2015 compliance deadline. Given that total annual emissions reported for 2011 that would have been covered by the program were about 150 million metric tons, the expected compliance obligation in 2015 is anticipated to be on the order of 300 million metric tons.[4] With 647 million allowances available in 2015, plus offset credits, there is no plausible set of conditions that would make the staff proposal unable to contain allowance prices in 2015, consistent with the Board directive in Resolution 12-51.

The effectiveness of the staff proposal is reduced as the program approaches 2020. For example, at the November 1, 2018 compliance deadline, cumulative emissions from 2013 to 2017 are uncertain, but could be on the order of 1,450 million metric tons if current emission rates and trends continue.[5] The total number of allowances eligible for use at the November 1, 2018 compliance deadline would be about 1,420 million from the 2013 to 2017 budget years, and 121 million from the existing Reserve, for a total of about 1,540 million allowances. Again, this figure does not include the offset credits that could also be used for compliance. The staff proposal makes an additional 96.5 million allowances eligible from the 2018 to 2020 budget years, bringing the total to about 1,637 million allowances plus offset credits. If the full 8% offset limit were used

[4] Calculated from 2011 reported greenhouse gas emissions data from electric power entities and facility level non-biogenic CO_2e available at http://www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/2011_ghg_emissions_summary_revised.pdf and http://www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/2011_ghg_emissions_spreadsheet.xlsx.

[5] Emissions calculated from 2011 reported greenhouse gas emissions data from electric power entities, transportation fuel suppliers, natural gas suppliers, and facility level non-biogenic CO_2e available at http://www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/2011_ghg_emissions_summary_revised.pdf and http://www.arb.ca.gov/cc/reporting/ghg-rep/reported_data/2011_ghg_emissions_spreadsheet.xlsx. Emission trends based on performance of complementary policies in the Discussion Draft Economic Analysis Supporting the Cap-and-Trade Program. WCI Economic Modeling Team. May, 2012. Available at http://www.westernclimateinitiative.org/document-archives/Economic-Modeling-Team-Documents/Discussion-Draft-Economic-Analysis-Supporting-CA-and-QC-Linking/

(which may be anticipated if emissions are higher than expected and allowance prices are near the Reserve prices), the available compliance instruments would be nearly 25% higher than anticipated emissions. This result suggests that the staff proposal would likely be effective under most plausible circumstances.

The staff proposal does not increase the total number of allowances available for the full period of 2013 to 2020. Consequently, the proposal is effective in maintaining the program's environmental objectives. 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.

III. ENVIRONMENTAL, AIR QUALITY, AND ENVIRONMENTAL JUSTICE IMPACTS

A. Environmental Analysis

1. Introduction

This chapter provides an environmental analysis (EA) for the proposed amendments to the California Cap on GHG Emissions and Market-Based Compliance Mechanisms (Cap-and-Trade Regulation). In general, the proposed amendments include changes in market program implementation, offset program implementation, and allowance allocation, as well as clarifications to the definition of resource shuffling, provisions to exempt certain emissions from incurring a compliance obligation under the program, and the addition of one new offset protocol. Based on ARB's review, staff has determined that the proposed regulatory amendments to the Cap-and-Trade Regulation would not result in any new significant adverse impacts or an increase in the severity of any significant impacts on the environment as previously identified in the *Functional Equivalent Document prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms* (2010 FED) and may provide air emissions benefits as compared to current practices. An EA for the proposed addition of a new Compliance Offset Protocol for Mine Methane Capture (MMC Protocol) is included in the separate Staff Report prepared for the proposed protocol, included as Appendix A to this ISOR.

2. Environmental Review Process

ARB is the lead agency for the proposed Regulation and has prepared this EA pursuant to its regulatory program certified by the Secretary of the Natural Resources Agency (14 CCR 15251(d); 17 CCR 60005-60007). In accordance with Public Resources Code (PRC) section 21080.5 of the California Environmental Quality Act (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).

As required by ARB's certified regulatory program (CRP), ARB has prepared this EA to assess the potential for significant adverse and beneficial environmental impacts associated with the proposed amendments to the Cap-and-Trade Regulation and to provide a succinct analysis of those impacts (Title 17,CCR,Section 60005). The resource areas from the *CEQA Guidelines Environmental Checklist* were used as a framework for assessing the potential for significant adverse impacts (17 CCR 60005(b)). This EA was conducted to evaluate any reasonably foreseeable direct or indirect physical change in the environment resulting from the methods of compliance

available to covered entities associated with the proposed regulatory amendments. The EA for the proposed MMC Protocol, contained in Appendix A to this ISOR, evaluates the reasonably foreseeable direct or indirect physical change in the environment that could result from development of projects under the proposed protocol.

If comments received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in the Final Statement of Reasons (FSOR) prepared for the proposed regulatory amendments. The written responses to environmental comments will be approved prior to final action on the proposed regulatory amendments (17 CCR 60007(a)). If the proposed regulatory amendments are adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection (17 CCR 60007(b)).

3. Prior Environmental Analysis

The analysis of the proposed regulatory amendments and the analysis of the proposed MMC Protocol rely on the prior environmental analyses prepared for the Cap-and-Trade Regulation as summarized below.

ARB hereby incorporates the documents described below containing the environmental analyses for the 2010 Cap-and-Trade Regulation as well as the 2012 Cap-and-Trade Regulation amendments. These documents are either available on ARB's website at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm and http://www.arb.ca.gov/regact/2012/capandtrade12/capandtrade12.htm respectively, or at ARB's Climate Change Program Monitoring Section located at 1001 I Street in Sacramento, California.

a) Cap-and- Trade Regulation (2010)

The Board adopted the Cap-and-Trade Regulation in October 2011. ARB prepared a programmatic EA for the Cap-and-Trade Regulation in the 2010 FED, included as Attachment O to the Staff Report: Initial Statement of Reasons (ISOR) released for public review and comment in November 2010 (CARB 2010d). The 2010 FED analysis was based on the expected compliance responses of the covered entities, identified as: (1) upgrade equipment; (2) decarbonization (fuel switching); (3) implement process changes; and (4) surrender compliance instruments. The 2010 FED also analyzed the potential indirect impacts associated with development of offset projects based on the four Compliance Offset Protocols: (1) Ozone Depleting Substances Projects (ODS); (2) Livestock Projects; (3) Urban Forest Projects; and (4) U.S. Forest Projects. The 2010

FED includes the environmental and regulatory setting information for all of the resource areas.

The 2010 FED concluded that covered entities' compliance with the Cap-and-Trade Regulation would result in beneficial impacts to air quality through reductions in emissions, including GHGs, criteria pollutants, and toxics, and beneficial impacts to energy demand. It concluded there would be less-than-significant or no impact to aesthetics, agricultural and forest resources, hazards, land use, noise, employment, population and housing, public services, recreation, transportation and traffic, and utilities/service systems. The 2010 FED concluded there could be short-term construction-related potentially significant adverse impacts to air quality, biological resources, cultural resources, geology/soils and minerals, and hydrology/water quality, due to construction activities for facility-specific projects. Although the potential for adverse localized air quality impacts were found to be highly unlikely, the 2010 FED conservatively considered them potentially significant. The 2010 FED concluded that implementation of offset projects under the four approved Compliance Offset Protocols would also result in beneficial impacts to GHG emissions and no adverse impacts or less-than-significant impacts in all resource areas except for the following: implementation of projects under the Livestock Protocol has the potential for significant adverse impacts to odors, and construction impacts to cultural resources, noise, and transportation/traffic; implementation of projects under the Urban Forestry Protocol has the potential for significant adverse impacts to cultural resources; and implementation of projects under the Forestry Protocol has the potential for significant adverse impacts to biological resources and land use.

The 2010 FED identified mitigation that could reduce most of the identified impacts to a less-than-significant level. The 2010 FED relied on the agencies with local permitting authority to analyze site-or project-specific impacts because the programmatic 2010 FED could not determine with any specificity the project-level impacts, and ARB does not have the authority to require project-level mitigation for specific projects carried out to comply with the Cap-and-Trade Regulation. Because the programmatic analysis of the 2010 FED could not determine project-specific details of impacts and mitigation, and there is an inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts, the 2010 FED took a conservative approach in its post-mitigation significance conclusion finding potentially significant impacts to these resource areas as significant and unavoidable.

The Board approved written responses to comments on the 2010 FED and adopted findings for the significant adverse impacts in Resolution 11-32 adopting the Cap-and-Trade Regulation. The written responses to environmental comments were included in the Final Statement of Reasons (FSOR) prepared for the Regulation (CARB 2011a,

CARB 2012d). The Board also adopted the *Adaptive Management Plan* (CARB 2011b) to address any unanticipated localized air quality impacts resulting from the Cap-and-Trade Regulation and any unanticipated biological resource impacts resulting from implementation of projects under the Forestry Protocol. These documents can be found on the Cap-and-Trade Program website, http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

b) Amendments to the Cap-and Trade Regulation (2012)

In 2012, ARB proposed two sets of amendments to the Cap-and-Trade Regulation. The first set of amendments, related to program implementation, was approved by the Board in June 2012. The second set of amendments, related to jurisdictional linkage with Québec, was approved by the Board in April 2013. An EA prepared for these amendments was included in Chapter IV of the Staff Report: Initial Statement of Reasons entitled *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 Jurisdictions* (CARB 2012c).

The 2012 EA concluded the amendments to clarify the Cap-and-Trade Regulation to help ARB implement, oversee, and enforce the Regulation would not change what was already required or the methods of compliance by covered entities evaluated in the 2010 FED (i.e., upgrade equipment, decarbonize, implement process changes, and surrender compliance instruments), and therefore the potential for environmental impacts fell within the scope and scale of those already analyzed. The analysis also considered the potential for indirect environmental impacts resulting from California-covered entities acquiring offset credits from projects in Québec because implementation of the linkage amendments could result in California entities acquiring credits from offset projects under Québec's Digesters (i.e., livestock), ODS, and Landfill Gas Offset Protocols. The EA relied on the prior EA conducted for California's ODS and Livestock Offset Protocols and ARB's Landfills Regulation because Québec's protocols are substantially similar. Those prior EAs concluded that implementation of these types of offset projects would result in beneficial impacts to GHG emissions and no adverse impacts, or less-than-significant impacts, in all resource areas, except implementation of the Livestock Protocol has the potential for significant adverse impacts to odors, cultural resources, noise, and transportation/traffic. The analysis referenced recognized mitigation measures for these impacts and determined that these impacts can be avoided or reduced to a less-than-significant level. However, because the authority to determine project-level impacts and require project-level mitigation lies with the permitting agency for individual projects, in this case Québec agencies, and there is inherent uncertainty in the degree of mitigation ultimately implemented, the analysis took a conservative approach in its post-mitigation significance conclusions

finding that impacts to odors, cultural resources, and transportation/traffic in Québec may remain significant after mitigation.

The Board approved written responses to comments on the EA and adopted findings for the significant adverse impacts in Resolution 13-7 adopting the linkage amendments. The written response to comments for the first set of amendments are included in the FSOR released in July 2012 (CARB 2012d) and for the linkage amendments in the FSOR released May 2013 (CARB 2013a). These documents can be found on the Cap-and-Trade Program website, http://www.arb.ca.gov/regact/2012/capandtrade12/capandtrade12.htm.

4. Scope of Analysis

The EA provided in this Chapter for the proposed regulatory amendments is intended to amend the previously certified 2010 FED as supplemented by the 2012 EA described above. The EA for the proposed MMC Protocol, provided in Appendix A to this ISOR, is also intended to supplement the 2010 FED analysis. These analyses include only that information necessary to make the prior 2010 FED adequate for the program as revised by the proposed regulatory amendments and addition of the proposed protocol.[6] The focus is on the potential for adverse impacts associated with incremental changes to the previously adopted program as analyzed in the certified environmental document. For the proposed amendments to change market program implementation, offset program implementation, and allowance allocation, to clarify the definition of resource shuffling, and provide an exemption of certain emissions from incurring a compliance obligation, the discussion in this Chapter addresses only those resource areas that are potentially affected by the changes. If there is no discussion of a resource area, it is because staff has determined that the proposed amendments would not result in any new significant adverse impacts or an increase in the severity of any significant impacts on the environment as previously analyzed in the 2010 FED. For the proposed MMC Protocol, every resource area is covered in the EA provided in the Staff Report in Appendix A of this ISOR so as to remain consistent with the chapters prepared for the four protocols in the 2010 FED. The analysis in these documents is necessarily programmatic in nature because site-specific or project-specific aspects of environmental impacts cannot be precisely described at this time.

[6] See eg. CEQA Guidelines sections 15164 , 15163(b).

5. Proposed Amendments

a) Description

Chapter II of this ISOR provides detailed information on the proposed amendments to the Cap-and-Trade Regulation. The description of proposed MMC Protocol is included in the separate Staff Report prepared for that protocol. As briefly summarized below, the proposed regulatory amendments would include the following: (1) changes in market program implementation and offset program implementation, (2) changes in allowance allocation, (3) clarifying language on the definition of resource shuffling, (4) provisions to include new sectors and exempt certain emissions from incurring a compliance obligation under the program, and (5) the addition of one new offset protocol.

(1) Market Program and Offset Program Implementation

Staff is proposing modifications related to the implementation of the auction and trading provisions within the Auction Platform and Compliance Information Tracking Services System (CITSS), in addition to modifications to the current schedule for auctions and reserve sales. Staff is proposing modifications to the existing information disclosure requirements to ensure rigorous oversight of the market program, and to help ARB monitor relationships between consultants and market participants. Staff is also proposing additional information requirements related to CITSS instrument transfers.

Regarding offset program implementation, staff is proposing amendments relating to project listing requirements, monitoring and reporting requirements, verification body requirements, conflict of interest requirements, compliance offset credit issuance, timing and deadlines, and roles of air quality districts. Staff is also proposing changes to clarify that invalidation requirements are consistent for all project types, and to allow air districts to have multiple roles in the offset program. All of the above changes are primarily administrative in nature and are discussed collectively in the environmental impact section of this Chapter.

(2) Allowance Allocation

For the purposes of allowance allocation, staff is considering allocation for new sectors and changes to transition assistance for existing sectors. The amendments include a mechanism for allocation of allowances to several sectors that are currently covered by the program who previously did not receive an allocation, including State universities and eligible public service facilities, natural gas distribution facilities, public wholesale water agencies, and electricity generators who

have contracts that cannot be renegotiated to include a CO_2 cost (legacy contract generators). In addition, the proposed regulatory amendments will shift the scheduled reduction in allocation assistance factors by one compliance period. Each of these four proposed amendments is discussed separately in the environmental impact section of this Chapter.

(3) Resource Shuffling

Pursuant to the direction in Board Resolution 12-33, staff is proposing additional clarity relating to the definition of resource shuffling, and will identify "safe harbors" that ARB does not consider resource shuffling.

(4) Covered Sectors and Exempt Emissions

Staff is proposing regulatory amendments to exempt certain emissions from incurring a compliance obligation under the program. This category of changes includes an extension of exemption for military facilities. In addition, this category also includes short-term exemptions for certain emissions from combined heat and power facilities (CHP) and district heating facilities, and waste-to-energy facilities, until the second compliance period in 2015. Each of these three proposed amendments is discussed separately in the environmental impact section of this Chapter.

(5) New Offset Protocol

The amendments propose one new offset protocol to help ensure that an adequate supply of low-cost compliance instruments will be available for compliance. A detailed description for the MMC Protocol is included in the separate Staff Report prepared for the protocol, included as Appendix A to this ISOR.

b) Methods of Compliance

(1) Market Program and Offset Program Implementation

The proposed regulatory amendments to market program implementation and offset program implementation do not change the stringency or effectiveness of the current program provisions and would not change what is already required or the methods of compliance by covered entities as evaluated in the 2010 FED (i.e., upgrade equipment, decarbonization, process changes, and surrender of compliance instruments).

(2) Allocation

The proposed amendments relating to allocation would not change the compliance responses available to these entities from what was analyzed in the 2010 FED.

(3) Resource Shuffling

The proposed clarifying language is intended to provide guidance to in-state electricity generators and out-of-state electricity importers on actions prohibited under the program and would not affect the compliance responses available to these entities from what was analyzed in the 2010 FED.

(4) Covered Sectors and Exempt Emissions

The extension of the exemption for military facilities would not change the actions or compliance responses of these facilities from what was previously evaluated in the 2010 FED.

The proposed amendments to exempt certain emissions from CHP, district heating facilities, and waste-to-energy facilities in the first compliance period would not change the methods of compliance available to these entities from what was previously analyzed in the 2010 FED.

(5) New Offset Protocol

The methods of compliance for the proposed MMC Protocol is discussed in the EA chapter within the Staff Report, prepared separately for the protocol. Please refer to Appendix A to this ISOR for this Staff Report.

6. Environmental Impacts

(1) Market Program and Offset Program Implementation

The compliance obligations available to covered entities would not change as a result of these amendments from what was previously analyzed in the 2010 FED. The proposed amendments relating to market program implementation and offset program implementation do not change the stringency or effectiveness of the current program provisions, and do not change what is already required or the methods of compliance by covered entities as evaluated in the 2010 FED. Market program and offset program implementation would not result in any new significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED.

(2) Allowance Allocation

Universities and Public Service Facilities.

The proposed allocation of allowances to universities and eligible public service facilities is intended to provide transition assistance to these entities in recognition of their leadership in reducing GHG emissions. The first surrender obligation is not until November 2014 at which time only 30% of allowances for 2013 emissions are due. ARB does not have information at this time on how university and public service facilities may choose to comply with the program, because the method of compliance is chosen by each separate entity. Regardless, the proposed regulatory amendments do not change the methods of compliance available to these entities as evaluated in the 2010 FED and would not result in any new significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED. While unlikely, any increase in emissions above business as usual from these facilities would still be subject to applicable local air quality permits. Adherence to all required local permitting regulations would ensure that any changes in emissions would not result in any significant adverse impacts to air quality.

Staff also considered the possibility that these entities could forego future efficiency improvements in anticipation of receiving a direct allocation of allowances, thereby resulting in fewer co-pollutant benefits. It is not possible at this time to determine whether these facilities would choose to forego additional improvements because an entity's decision to implement such changes is not mandated by the program. Business decisions, including the cost of allowances compared to cost of changes, also factor into the decision to implement process changes. Therefore, it is too speculative to determine whether a facility that may have planned to implement efficiency improvements would now forego these plans as a result of the amendments.

Legacy Contract Generators

The proposed allocation of transition assistance to eligible legacy contract generators would be short-term for most generators (i.e., for the first compliance period only), and would only apply to generators that entered into long-term fixed price contracts that were signed prior to AB 32 and contain no reasonable way to pass compliance costs down to the purchaser. For a small subset with industrial counterparties the allocation would be for the entire term of the contract but the counterparty allocation would be adjusted so overall there would be limited if any additional allocation. In general, legacy contract generators are limited in the methods of compliance available to them. While legacy contract generators have the ability to upgrade

equipment and surrender compliance instruments, bio-derived fuels are often inaccessible to facilities (thereby limiting the ability to decarbonize through fuel switching), and implementing a major process change often requires a complete overhaul of the facility which is both costly and time consuming. Staff believes that allocating allowances to these entities provides additional time for them to finance, plan for and make changes to their operations in order to reduce their emissions, in light of their limited options for compliance.

Because the first compliance surrender date is not until 2014, ARB is not able to determine at this time how legacy contract generators may choose to comply with the program. Regardless, the proposed regulatory amendments do not change the methods of compliance available to these entities as evaluated in the 2010 FED, and the impacts of these actions fall within the scope and scale of those already analyzed in the 2010 FED. Therefore, this amendment would not result in any new significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED. While unlikely, any increase in emissions above business as usual from these facilities would still be subject to applicable local air quality permits. Adherence to all required local permitting regulations would ensure that any changes in emissions would not result in any significant adverse environmental impacts.

Staff also considered the possibility that these entities may have begun to plan or implement efficiency improvements at their facilities, potentially resulting in co-pollutant benefits since the start of the program in January 2013. The proposed transition assistance could cause some entities to delay making additional improvements, thereby reducing potential co-pollutant benefits in the near-term. Nonetheless, it is unlikely that a legacy contract generator would completely forego implementing future planned improvements, because the transition assistance would not extend through the second or third compliance periods.

Natural Gas Suppliers

Staff is proposing an allocation for natural gas suppliers in order to ensure proper transitional assistance to protect rate payers from natural gas utility rate increases. While natural gas suppliers have the ability to upgrade equipment (e.g., install more efficient infrastructure, etc.) and surrender compliance instruments, other options including decarbonizing through fuel switching and implementing major process changes may be less feasible. . The costs must be weighed against alternative means of bringing less carbon intensive energy to consumers. Moreover, fuel switching (e.g., the choice to buy an electric versus gas stove), conservation, and implementation of major process changes (e.g., installing a more efficient water heater) relating to natural gas use are generally considered to be the prerogative of

the end user. Similarly to electrical distribution utilities, the natural gas suppliers can provide programs to end-users to promote these shifts. Thus, staff is proposing transition assistance for natural gas suppliers in the first compliance period, as these entities are best situated to utilize the value of allowances for ratepayer benefit.

As previously discussed, because the first compliance surrender date is not until 2014, ARB cannot determine at this time how natural gas suppliers may choose to comply with the program. Regardless, the proposed amendments do not change the methods of compliance available to these entities as evaluated in the 2010 FED, and the impacts of these actions fall within the scope and scale of those already analyzed in the 2010 FED. Therefore, this amendment would not result in any new significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED. While unlikely, any increase in emissions above business as usual from these facilities would still be subject to applicable local air quality permits. Adherence to all required local permitting regulations would ensure that any changes in emissions would not result in any significant adverse environmental impacts.

Staff also considered the possibility that natural gas suppliers may have started to plan or implement certain efficiency improvements or programs within their service territories, potentially resulting in co-pollutant benefits since the start of the program in January 2013. If an entity decides to undo such efficiency improvements, or foregoes making additional improvements as a result of the proposed allocation, a loss of co-pollutant benefits could result. Any forgone potential co-pollutant benefits do not represent a significant adverse impact to air quality.

Public Wholesale Water Agencies

Staff is proposing an allowance allocation for two public wholesale water agencies, the Department of Water Resources and the Metropolitan Water District, in order to ensure proper assistance to protect water rate payers from rate increases. While public wholesale water agencies have the ability to upgrade equipment (e.g., install more efficient infrastructure, etc.) and surrender compliance instruments, other options including decarbonizing through fuel switching and implementing major process changes may be less feasible. Thus, staff is proposing assistance for public wholesale water agencies for all compliance periods, as these entities are best situated to utilize the value of allowances for ratepayer benefit.

As previously discussed, because the first compliance surrender date is not until 2014, ARB cannot determine at this time how public wholesale water agencies may choose to comply with the program. Regardless, the proposed amendments do not

change the methods of compliance available to these entities as evaluated in the 2010 FED, and the impacts of these actions fall within the scope and scale of those already analyzed in the 2010 FED. Therefore, this amendment would not result in any new significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED. While unlikely, any increase in emissions above business as usual from public wholesale water agency facilities would still be subject to applicable local air quality permits. Adherence to all required local permitting regulations would ensure that any changes in emissions would not result in any significant adverse environmental impacts.

Staff also considered the possibility that public wholesale water agencies may have started to plan or implement certain efficiency improvements or programs within their service territories, potentially resulting in co-pollutant benefits since the start of the program in January 2013. If an entity decides to undo such efficiency improvements, or foregoes making additional improvements as a result of the proposed allocation, a loss of co-pollutant benefits could result. However, any forgone potential co-pollutant benefits do not represent a significant adverse impact to air quality.

Shift in Assistance Factors

Staff is proposing a shift in assistance factors by one compliance period in order to provide additional certainty and time to industry to successfully transition to lower-carbon production methods. This amendment also allows additional time for staff to obtain the results of new research that will improve the data, measurement, and metrics of economic leakage risk and will provide additional insights into the potential leakage risks posed in the long-term for industrial sectors.

The proposed shift would only affect those industry sectors that are in the medium or low leakage risk classifications, and do not change the stringency or effectiveness of the current program provisions as the cap on emissions would still be maintained. Staff believes that the shift is necessary in order to maintain a conservative approach to leakage risk, and will reassess leakage risk classifications based on the results of the new research. While the proposed shift in assistance could cause some entities to delay making additional improvements in the near-term, it is unlikely that an industry would completely forego implementing future planned improvements since assistance factors for the medium and low leakage risk categories would be reduced again in the third compliance period.

As previously discussed, because the first compliance surrender date is not until 2014, ARB cannot determine at this time how all sectors of industry may choose to comply with the program. Regardless, the proposed amendments do not change

the methods of compliance available to these entities as evaluated in the 2010 FED, and the impacts of these actions fall within the scope and scale of those already analyzed in the 2010 FED. Therefore, this amendment would not result in any new significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED. While unlikely, any increase in emissions above business as usual from these industrial facilities would still be subject to applicable local air quality permits. Adherence to all required local permitting regulations would ensure that any changes in emissions would not result in any significant adverse environmental impacts.

(3) Resource Shuffling

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. 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.

(4) Covered Sectors and Exempt Emissions

Military Facilities

The exemption for military facilities from a compliance obligation under the program was included in the original 2010 Regulation as analyzed in the 2010 FED. Therefore, the potential for adverse impacts associated with the current proposal to extend this exemption falls within the scope and scale of those previously analyzed.

Combined Heat and Power and District Heating Facilities

Staff is proposing amendments to exempt qualified thermal output emissions from CHP and district heating facilities by placing allowances into these facilities' compliance accounts to cover the exempted emissions for the first compliance period only. These facilities will still reporting emissions and will be considered covered entities under the Program, though they will not have a compliance obligation in the first compliance period. Under the amendments, the Executive Officer will transfer the allocation directly into the entity's compliance account to satisfy the first surrender obligation occurring on November 2014. Therefore, the proposed amendments do not change the methods of compliance available to these entities as evaluated in the 2010 FED, and the impacts of these actions fall within the scope and scale of those already analyzed in the 2010 FED. As a result, this amendment would not result in any new significant impacts or an increase in severity

of any significant impacts previously identified in the 2010 FED. While unlikely, any increase in emissions above business as usual from these facilities would still be subject to applicable local air quality permits. Adherence to all required local permitting regulations would ensure that any changes in emissions would not result in any significant adverse environmental impacts.

Staff also considered the possibility that these entities may have started to implement additional efficiency improvements in anticipation of a compliance obligation in 2014, thereby potentially resulting in certain co-pollutant benefits since the start of the program in January 2013. It is not possible to determine whether these facilities did implement such changes because an entity's decision to implement such changes is not mandated by (or reported to) the program. Business decisions, including cost of allowances compared to cost of changes, factor into the decision to make these process changes. In addition, some facilities have indicated that this type of information is confidential because it can relate to both the cost of production and steam and electricity sales, which often have strategic business importance in negotiating future contracts. It is also too speculative to determine whether any facilities that may have implemented such changes would undo such efficiency improvements as a result of the amendments, which could also potentially lead to a loss of co-benefits realized. Even so, it is unlikely that a facility would completely forego future planned improvements or undo existing improvements as a result of the proposed short-term exemption, since all emissions would be covered in the second and third compliance periods. Further, once natural gas suppliers join the program in 2015, eligible CHP and district heating face similar compliance costs whether a covered entity or not. Even if future co-benefits are not realized in the near-term, any forgone future potential co-benefits do not represent a significant adverse impact to air quality.

Waste-to-energy Facilities

Staff is proposing regulatory amendments to exempt certain emissions from waste-to-energy facilities by placing allowances into these facilities' compliance accounts in order to cover the exempted emissions for the first compliance period only. These facilities will still report emissions and will be considered covered entities under the program, though they will not have a compliance obligation in the first compliance period. Under the amendments, the Executive Officer will transfer the allocation directly into the entity's compliance account to satisfy the first surrender obligation occurring on November 2014. The proposed amendments do not change the methods of compliance available to these entities as evaluated in the 2010 FED, and the impacts of these actions fall within the scope and scale of those already analyzed in the 2010 FED. Therefore, this amendment would not result in any new

significant impacts or an increase in severity of any significant impacts previously identified in the 2010 FED.

Staff considered the possibility that some of these entities may have begun to plan or implement energy efficiency improvements in anticipation of a compliance obligation in 2014, thereby potentially resulting in co-pollutants benefits since the start of the program in January 2013. As discussed in the *Municipal Solid Waste Thermal Technologies* draft white paper, released jointly by ARB and the Department of Resources Recycling and Recovery (CalRecycle), waste-to-energy facilities have multiple air pollution control devices to limit emissions of sulfur oxides, nitrogen oxides, particulate matter, and other pollutants (CalRecycle 2013). The study notes that additional strategies to reduce GHGs and co-pollutants from waste-to-energy facilities may only achieve modest emissions reductions (CalRecycle 2013).[7] CalRecycle concluded that waste-to-energy facilities in California have limited options for the reduction of GHG emissions (CalRecycle 2013). This suggests that it is unlikely that these entities had to date taken actions to implement energy efficiency improvements at their facilities that would have led to co-pollutant benefits since the start of the program in January 2013. Further, given that the proposed exemption is only for the first compliance period, it is unlikely that any efficiency improvements implemented would be reversed in response to this short term exemption. It is also unlikely that these entities would completely forego future planned improvements as a result of the proposed short-term exemption. While it may be possible that certain co-benefits may not be realized for the first compliance period, a reduction in co-benefits does not represent a significant adverse impact air quality. All facilities would still be required to limit their emissions under all applicable local air quality permits. Adherence to all required local permitting regulations would ensure that these amendments would not result in any significant adverse air quality impacts.

(5) New Offset Protocol

Staff found that implementation of projects based on the proposed MMC Protocol could result in potentially significant impacts on the physical environment. A detailed EA for the MMC Protocol is included in the separate Staff Report prepared for the MMC Protocol included as Appendix A to this ISOR.

[7] Other options to reduce GHGs and co-pollutants, when a full "life-cycle" approach is used include: (1) improvements in front end pre-processing to recover more recyclables (e.g., glass, plastics, cardboard) prior to combustion (2) upgrades to the incinerator, boiler, turbine, or generator that could provide some modest improvements in the efficiency of the plant, and associated electricity generated per ton of waste, (3) improvements in metals recovery equipment to increase the recovery of metals from the waste ash, or (4) increases in the use of ash in products such as construction materials where it could replace virgin materials that would be mined or otherwise produced through processes that result in more GHG emissions (CalRecycle 2013).

7. Cumulative Impacts

Cumulative impacts are impacts on the environment that result from the incremental impacts of a proposed project when added to other past, present, and reasonably foreseeable future actions.

The 2010 FED for the Cap-and-Trade Regulation included a cumulative analysis section that examined impacts associated with the entire Cap-and-Trade program, including the offset protocols, based on the Regulation's contribution to environmental impacts in combination with the environmental effects of the ongoing, adopted, and reasonably foreseeable Scoping Plan measures and the State Implementation Plan (SIP), which includes goods movement measures (heavy-duty vehicle efficiency, ship electrification, port drayage truck measures, and vessel speed reduction).

As described above, the proposed amendments to the Cap-and-Trade Regulation will not change how covered entities comply with the Regulation (i.e., upgrade equipment, decarbonization, implement process changes and surrender compliance instruments) as evaluated in the 2010 FED. Therefore, the amendments would not contribute to any additional or more severe cumulative impacts than those already evaluated and disclosed in the 2010 FED. The EA for the MMC Protocol, as provided in Appendix A to this ISOR, includes a protocol specific cumulative impacts discussion.

8. Alternatives

The 2010 FED considered a reasonable range of action alternatives potentially capable of reducing the proposed Regulation's environmental effects while accomplishing most of the project objectives. The alternatives included a No Project Alternative, a Cap-and-Trade Program with Alternative Design Features Alternatives, (including a border adjustment, 100% auction allowance, a different offset limit, facility-specific caps, restricting trading in impacted locations, disallowing banking of allowances, and not linking with other cap-and-trade programs), and Additional Source-Specific Command-and-Control Regulations Alternative, and a Carbon Fee Alternative. In 2011, when the Board adopted the Cap-and-Trade Regulation, it found that adoption and implementation of the Cap-and-Trade Regulation was the most desirable, feasible, and appropriate action for achieving the objectives of the project, and it rejected the other alternatives as either less desirable or infeasible based on consideration of the relevant factors identified in the 2010 FED as described in the Findings adopted with Resolution 11-32.

As described above, the current proposed regulatory amendments to change market program implementation, offset program implementation, and allocation, to clarify the

definition of resource shuffling, and to exempt certain emissions from incurring a compliance obligation under the program, do not change the methods of compliance available to these entities as analyzed in the 2010 FED. Because the impacts of these actions 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, no additional alternatives analysis for these amendments is required. The EA for the MMC Protocol includes a protocol specific alternatives analysis.

B. Environmental Justice

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies. ARB is committed to making environmental justice an integral part of its activities. The Board approved its Environmental Justice Policies and Actions (Policies) on December 13, 2001, to establish a framework for incorporating environmental justice into ARB's programs consistent with the directives of State law (CARB 2001). These policies apply to all communities in California, but recognize that environmental justice issues have been raised more in the context of low-income and minority communities.

As part of the economic, emissions, and environmental assessment of the Cap-and-Trade Regulation, staff assessed the emission reduction opportunities available to California sources covered by the proposed amendments to this Regulation. This evaluation considered the potential for the incentives and flexibility inherent in the cap-and-trade program to result in direct, indirect, and cumulative emission impacts, including localized impacts in communities that are already adversely affected by air pollution. Based on the available data and current law and policies that control localized air pollution, and expected compliance responses to the Cap-and-Trade Regulation, ARB concluded that increases in localized air pollution (including toxic air contaminants and criteria air pollutants) attributable to the Cap-and-Trade Program are extremely unlikely. For more information see Chapter VII. Co-Pollutant Emissions Assessment of the 2010 ISOR and Appendix P: Co-Pollutant Emissions Assessment (CARB 2010b; CARB 2010d).

As previously mentioned, since the compliance response resulting from the proposed amendments is expected to be within those already evaluated in the 2010 FED, staff anticipates that the impacts and benefits will also be equivalent. For additional information on the environmental justice impacts associated with the two proposed offset protocols, please refer to Appendix A to this ISOR.

Nevertheless, as part of ARBs Adaptive Management Plan, at least once each compliance period, ARB will use information collected through the mandatory reporting regulation, the Cap-and-Trade Regulation, the industrial efficiency audit, and other sources to evaluate how facilities are complying with the Cap-and-Trade Regulation (CARB 2011b). ARB will also solicit information from local air districts regarding permit modifications and new permit applications for covered sources. 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 in California can be attributed to the Cap-and-Trade Regulation (including the proposed amendments) during this periodic review, ARB will consider whether these impacts affect the achievement of the program objectives. If so, ARB will promptly develop and implement appropriate responses. Potential responses ARB would consider include, but are not limited to, using allowance value from the Cap-and-Trade Program to mitigate localized emissions increases, providing incentives for energy efficiency and other emissions-reduction activities within the community, or restricting trading or prohibiting certain compliance responses in specifically identified communities. These potential future responses are not, however, warranted based on currently available information, and their imposition today would unnecessarily conflict with AB 32's other objectives.

IV. ECONOMIC IMPACTS OF THE PROPOSED REGULATION

A. ECONOMIC AND ALTERNATIVES ASSESSMENT

1. Summary of Economic Impacts

The amendments proposed in this regulation clarify the existing Cap-and-Trade Regulation (Regulation) allowing ARB to implement, oversee, and enforce the Regulation.

The amendments proposed in this Regulation 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.

The amendments proposed in the Regulation 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 covered entities receiving allowances through the second compliance period. Allocation of allowances will reduce the near-term compliance cost for covered facilities that receive allowances.

The Regulation temporarily exempts waste-to-energy emissions, offshore oil and gas production facilities and extends the exemption for military facilities removing their compliance obligation.

The Regulation includes two lead acid battery recycling facilities as covered. These facilities are covered by the original Cap-and-Trade Regulation because of their emissions. However, because process emissions were not being reported at the time of the original Regulation it was unknown that these facilities exceeded the emissions threshold. These sectors will be receiving a product based benchmark similar to other industrial facilities. The inclusion of these sectors in the program does not represent new impacts to the State as the analysis for the original Regulation included all energy using sectors as covered entities.

The amendments proposed in this Regulation specify further mechanisms for cost containment to help ensure that allowances prices do not rise above the price of the highest priced tier in the Allowance Price Containment Reserve.

The amendments proposed include implementation related provisions to clarify existing requirements for offset project operators and assigned project designees. The amendments also propose to allow air districts to have multiple roles in the offset program. As participation in the offset program is voluntary and these amendments are related to implementation, the proposed changes do not add cost to the covered entities over what has been previously estimated for the existing Regulation. Finally, the amendments propose a new offset protocol. Additional protocols will help ensure that an ample supply of low-cost compliance instruments will be available for compliance. The additional protocols will not require additional ARB resources to administer or enforce.

The collection of changes does not add any additional costs over what was anticipated in the original Cap-and-Trade Regulation to regulated entities and some changes will have the effect of reducing costs to some regulated entities in the early years of the program.

2. Legal Requirements

Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment must include consideration of the impact of the proposed Regulation on California jobs; the expansion, elimination, or creation of businesses; and the ability of California businesses to compete with businesses in other states.

Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance (DOF). The estimate shall include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State.

Finally, Health and Safety Code section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to a proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding $10 million in any single year.

3. Costs to State Government and Local Agencies

ARB anticipated that government entities covered by the Regulation would need to register for accounts, report transactions and disclose corporate affiliates when it adopted the Regulation in 2011, but the exact details of these requirements were unknown at the time. The proposed Regulation specifies exactly what information will be required. Complying with these requirements does not add any additional costs over what was originally assumed in the Regulation. The proposed Regulation provides for the allocation of allowances to State universities thus reducing their near-term cost of compliance from what was estimated in the original Regulation.

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. 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.

4. Costs to Businesses and Private Individuals

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 but the exact details of these requirements were unknown at the time. 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. There are no requirements placed on non-covered businesses or private individuals. 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 statewide

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.

5. STATEMENT OF THE RESULTS OF THE ECONOMIC IMPACT ASSESSMENT PREPARED PURSUANT TO GOVERNMENT CODE SEC. 11346.3(b)

In accordance with Government Code section 11346.3, the staff has determined that the proposed regulatory action would not eliminate existing businesses within the State of California, and would not affect the creation of new businesses or the expansion of existing businesses currently doing business in California. The proposed regulatory action would not eliminate jobs within the State of California, and would not affect the creation of jobs within California.

In general, small businesses in regulated sectors would not be subject to the proposed Regulation because their total GHG emissions are below the GHG reporting threshold, thereby exempting them from compliance obligations under the proposed Regulation.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), staff found that the reporting requirements of the proposed Regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

B. ALTERNATIVES ANALYSIS

Staff is required to consider alternatives to the proposed amendments for the Cap-and-Trade Regulation. For discussion of the alternatives considered, please refer to Chapter V of this ISOR, Alternatives Analysis.

V. ALTERNATIVES ANALYSIS

This Chapter provides an analysis of the alternatives to the proposed amendments for the Cap-and-Trade Regulation that staff considered. The discussion below describes the alternatives to the proposed changes. For each of the alternatives, staff outlines the costs and benefits of the approach and explains why it chose to propose the Cap-and-Trade Regulation and incorporated design features.

A. Alternatives to the Proposed Amendments to the Cap-and-Trade program

Staff analyzed five 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).

In evaluating these alternative approaches to the proposed Regulation, ARB staff found that none were as effective, or more effective, than the proposal in carrying out the goals of AB 32. 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 the following sections.

1. No Amendments (No Project Alternative)

The No Project Alternative defines a scenario in which ARB would not amend the Regulation with the proposed changes. Staff has assessed this alternative for each category of changes, as provided below.

a) Allocation

Under the No Project Alternative, proposed changes relating to the provision of allocation to universities and public service facilities, wholesale public water agencies, natural gas suppliers, and legacy contract generators, and the proposed shift in assistance factors for all industrial sectors by one compliance period, would not be implemented.

Staff propose to allocate allowances to university covered entities and public service facilities for transition assistance and to recognize their leadership in reducing GHG emissions and achieving additional environmental and economic benefits for California. Not providing additional allocation to these entities would remove the incentive to implement future energy efficiency improvements and continue other GHG reduction measures. The provision of direct allocation to natural gas suppliers is intended to benefit ratepayers in order to provide opportunities to reduce emissions without undue economic impacts. Providing allocation to natural gas suppliers protects ratepayers. The consignment produces funds that can be directed by CPUC for the benefit of ratepayers. The provision of allocation for legacy contract generators is intended to provide transitional assistance, pursuant to Board direction. Providing allocation to legacy contract generators gives them time to renegotiate their contracts. The provision for allocation to public wholesale water agencies is for the benefit of water ratepayers. Providing allocation is to mitigate the cost impact to ratepayers associated with the compliance obligations for electricity used to convey water. Finally, the increase in assistance factor levels in the second and third compliance periods is needed to provide additional certainty and time for industry to successfully transition to lower-carbon production methods while also allowing additional time for staff to obtain the results of new research that will improve the data, measurement, and metrics of economic leakage. Without this change, emissions leakage could increase for all industrial sectors under the program.

b) Covered Sectors/Emission Exemptions

Under the No Project Alternative, proposed changes relating to the addition of a newly covered sector (i.e., lead producers), and emission exemptions (i.e., CHP facilities, district heating facilities, military facilities and waste-to-energy facilities) would not be implemented.

Process emissions from lead production facilities were not included in the previous GHG reporting regulations under MRR. As a result, certain lead producers did not exceed the Cap-and-Trade emissions threshold and therefore were not considered covered entities under the Program. Without the proposed amendments, this oversight would not be corrected and reporting of process emissions would not be equitable across all industry sectors.

Staff believes it is appropriate to exempt military facilities in order to recognize the other mechanisms already in place that have the potential to achieve equivalent reductions through a broad-based approach that encompasses sources that are below applicability thresholds. Without the continued exemption of these facilities, the GHG reductions resulting from these mechanisms would not be recognized. Regarding CHP and district

heating facilities, small facilities that made the efficient, lower emission, choice to install CHP could be disadvantaged during the first compliance period than would similar, less efficiency facilities without CHP. Staff believes this outcome runs counter to the overall intent and goals of the program to encourage efficiency and GHG reduction measures, and thus proposes a limited exemption of these emissions. Lastly, in an attempt to be conservative, staff believes is appropriate to exempt waste-to-energy emissions during the first compliance period to allow for the completion of the inter-agency study that will determine the best approach to treat Municipal Solid Waste under the program.

c) Electricity

Under the No Project Alternative, proposed changes relating the definition of resource shuffling and requirements for RECs in the RPS adjustment provisions would not be implemented.

The clarifying language relating to resource shuffling is proposed in response to stakeholder concerns that activities that may be considered resource shuffling are not well defined in the Regulation but are nonetheless prohibited. Stakeholders argued that lack of clarity regarding resource shuffling could negatively affect California and western states electricity markets. Not providing additional clarity could make compliance with the Regulation more burdensome and could result in inhibiting legitimate activity in electricity markets.

The proposal to clarify REC requirements under specified sources is intended to ensure that RECs are not accounted for in multiple programs. Without these provisions, ARB would have no mechanism for tracking and informing others that renewable electricity generation was accounted for under this program. The proposal includes an adjustment to a compliance obligation for electricity procured to meet a California RPS requirement. Without these changes the original intent of the provision would not be met, and requirements to meet the intent of the program would not be clarified.

d) Cost Containment

Under the No Project Alternative, proposed changes relating to cost containment (i.e., increasing the availability of additional allowances, etc.) would not be implemented.

Pursuant to Board direction, the amendments relating to cost containment are intended to ensure that allowance prices do not exceed the highest price tier of the Reserve, while also minimizing the impact on existing allowances and maintaining the environmental integrity of the program. Not including additional cost containment mechanisms could increase the likelihood that allowances prices will exceed the highest

price ties of the Reserve, and could make the price of allowances more vulnerable to unlikely exogenous shocks to the market.

e) Market Implementation

Under the No Project Alternative, proposed changes relating to market implementation (i.e., corporate association disclosure, registration requirements, auction administration, etc.) would not be implemented. The proposed amendments relating to market implementation are intended to allow ARB to continue to properly implement and oversee the Regulation. Without these changes, program implementation and oversight would be less efficient and effective.

f) Offset Protocols and Offset Program Implementation

Under the No Project Alternative, proposed changes relating to both offset program implementation and the addition of new offset protocols would not be implemented. The changes made for offset program implementation are intended to aid ARB in continuing to successfully implement and oversee the offset program. Without these changes, ARB oversight and implementation of offset program would be less efficient and effective. The addition of new offset protocols is intended to increase the supply of offsets to the market thereby assisting in cost containment. Without the additional offset protocol, the likelihood that allowances prices will exceed the highest price tier of the Reserve is increased.

Under the No Project Alternative, staff would not make changes to the program that are necessary to achieve the goals of the Regulation. Staff has considered alternative means of achieving these goals and none were found to be as effective, or more effective, than the proposal in carrying out the goals of AB 32. No alternative considered by the agency would be more effective in carrying out the purpose for which the Regulation is proposed, or would be as effective as and less burdensome to affected individuals and businesses than the proposed Regulation. Therefore staff believes the amendments proposed in this Regulation are necessary.

2. Allocation Alternative

The New Sector Allocation Alternative defines a scenario in which ARB considers alternative allocation scenarios for sectors including legacy contract generators, universities and public service facilities, wholesale public water agencies, and natural gas suppliers. Staff discussed several alternatives with stakeholders during workshops and many individual meetings, and the proposed alternatives varied widely for each proposed allocation to new sectors. For example, stakeholders proposed allowance allocation to legacy contract generators for the full term of the contract. Staff rejected

this proposal because this does not allow for a price signal and cost pass through to the purchaser of the steam and/or electricity. It also does not recognize or encourage renegotiation. Staff did decide to offer allocation for those parties with an industrial counterparty because the purpose is different and it adjusts the counterparty allocation, correcting incentives and providing limited if any additional overall allocation. Staff also discussed with stakeholders the potential for moving the point of Regulation to that of the natural gas supplier. Because there are so many variations to the types of contracts this alternative would not resolve the issue.

For public wholesale water agencies, staff considered additional allocation levels. Staff rejected this scenario because the allocation is related to the electricity to convey water and should consistent with the allocation methodology for electrical distribution utilities.

Staff also considered reducing or removing assistance to universities and public service facilities. However, staff rejects these scenarios as they would neither recognize nor reward universities for their leadership in reducing GHG emissions as directed by Board Resolution 11-32.

Staff additionally considered reducing initial consignment requirements but this would not provide reductions in the residential and commercial uses of natural gas through end user changes or utility programs. .

Staff also considered removing the proposed shift in assistance factor levels for industry. As previously discussed, the changes are needed to provide additional certainty and time for industry to successfully transition to lower-carbon production methods while also allowing additional time for staff to obtain the results of new research that will improve the data, measurement, and metrics of economic leakage risk. Without this change, it is possible that the requirements for some EITE industries to reduce emissions may create a disadvantage for California facilities relative to out-of-state competitors who do not face similar requirements. Thus staff rejects the alternative to remove the shift in assistance factors until the leakage research is finalized.

Under the Allocation Alternative, staff would not make changes to the program that are necessary to provide assistance to new sectors including legacy contract generators, wholesale public water agencies, universities and public service facilities, and natural gas suppliers. No alternatives to allocation considered by ARB would be more effective in carrying out the purpose for which the Regulation is proposed, or would be as effective as and less burdensome to affected individuals and businesses in the state while achieving the purposes of the proposed Regulation. Therefore staff believes the amendments proposed in this Regulation are necessary.

Cost Containment Alternative

The Cost Containment Alternative defines a scenario in which ARB considers alternative mechanisms for cost containment in response to Board Resolution 12-51.

In a public workshop, staff considered alternative approaches to the design of one or more containment mechanisms in order to ensure the allowance price does not exceed the highest price tier of the Reserve. The alternatives were presented in two categories, alternative approaches to containing costs and alternative approaches to obtaining compensating emission reductions to maintain the environmental integrity of the program. The cost containment alternatives included injecting additional allowances at the highest price tier of the Reserve, allowing fulfillment of compliance obligation through a fixed price-per-ton payment at the highest price tier of the Reserve, delaying compliance obligation, and the cancellation of compliance obligation. Alternative approaches to maintaining the environmental objective of the program included redistributing existing allowances, committing to additional emissions reductions from the post 2020 period, mandating additional emission reductions from California sources, and obtaining emission reductions outside of California.

With input from stakeholders and the public, staff designed a cost containment mechanism that injects additional allowances at the highest price tier of the Reserve through the redistribution of existing allowances. This approach was supported by many stakeholders and was staff's preferred mechanism as it further ensures the allowance price will not exceed the highest price tier of the Reserve over a plausible range of future conditions and maintains the environmental integrity of the program. The other considered alternatives either did not meet all objectives of Resolution 12-51 or were not feasible under AB 32.

Some stakeholders also recommended that ARB use additional approaches in designing one or more cost containment mechanisms in satisfaction of the Board Resolution. Stakeholders expressed concern that the proposed cost containment mechanism does not guarantee that the allowance price will not exceed the highest price tier of the Reserve if there is a long-term imbalance in the supply and demand for allowances. Stakeholders recommended the creation of additional mechanisms designed to reduce the likelihood the allowance price will enter the Reserve by reducing the overall demand for compliance instruments and increasing the overall supply of compliance instruments early in the program. Stakeholders also recommended alternative cost containment mechanisms that would be triggered when the allowance price reaches the highest price tier of the Reserve. Some of these alternatives could impact the effectiveness of the program in reducing the statewide GHG emissions level to the 2020 target.

Staff reviewed all stakeholder recommendations, as well as written comments and public testimony received at two public workshops: Staff believes the proposed cost containment mechanism to best satisfy the objectives of Board Resolution 12-51 within the framework of AB 32.

VI. SUMMARY AND RATIONALE FOR PROPOSED REGULATION

The proposed amendments to the Cap-and-Trade Regulation are designed to help staff implement the cap-and-trade program and increase market security. This section discusses the requirements and rationale for each provision of the proposed amendments to the Cap-and-Trade Regulation.

Subarticle 2. Purpose and Definitions.

Section 95802. Definitions.

Summary of Section 95802 (a)(4)

New section 95802(a)(4) is added to provide a definition for activin.

Rationale for Section 95802 (a)(4)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(9)

New section 95802(a)(9) is added to provide a definition for Air Pollution Control District to support the identification of the eligibility for the exemption from a compliance obligation for Waste-to-Energy facilities.

Rationale for Section 95802 (a)(9)

This new definition is necessary to define the type of permit the facility must have to operate.

Summary of Section 95802 (a)(11)

New section 95802(a)(11) is added to provide a definition for almond.

Rationale for Section 95802 (a)(11)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(11)

Section 95802(a)(11) is deleted.

Rationale for Section 95802 (a)(11)

This deletion of this definition is necessary as it is no longer used in the crude petroleum extraction benchmarking. Instead, crude petroleum extraction is separated by thermal and non-thermal production.

Summary of Section 95802 (a)(13)

New section 95802(a)(13) is added to provide a definition for aluminum and aluminum billet.

Rationale for Section 95802 (a)(13)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(14)

Section 95802(a)(14) is modified to provide a definition for Asset Controlling Supplier to clarify these entities are considered suppliers of specified sources and renumbered to 19.

Rationale for Section 95802(a)(14)

This modification is necessary because these entities are assigned specific emission rates to be applied to electricity delivered to California from their declared resources.

Summary of Section 95802 (a)(16)

New section 95802(a)(16) is added to provide a definition for aseptic tomato paste.

Rationale for Section 95802 (a)(16)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(17)

New section 95802(a)(17) is added to provide a definition for aseptic whole / diced tomato.

Rationale for Section 95802 (a)(17)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(23)

Section 95802(a)(23) is modified to correct a typographical error and renumber to 29.

Rationale for Section 95802(a)(23)

This modification is necessary to delete the extra space between "integrates" and "resource".

Summary of Section 95802(a)(26)

Section 95802(a)(26) is modified to include dry gas production data into the calculation of barrel of oil equivalent and renumber to 32.

Rationale for Section 95802(a)(26)

This modification is necessary to include dry gas production data in the product benchmarks for the purposes of allowance allocation to the oil and gas extraction sector, pursuant to section 95891.

Summary of Section 95802 (a)(28)

New section 95802(a)(28) is added to provide a definition for baked potato chips.

Rationale for Section 95802 (a)(28)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(39)

Section 95802(a)(39) is added to provide a definition for boiler to identify that boiler emissions are included if they provided thermal energy and it was not an integral part of the cogeneration system.

Rationale for Section 95802(a)(39)

This term and definition is necessary allow for the inclusion of the emissions from a boiler if the boiler provided thermal output for sale under a legacy contract to a legacy contract counterparty.

Summary of Section 95802 (a)(42)

New section 95802(a)(42) is added to provide a definition for butter.

Rationale for Section 95802 (a)(42)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(43)

New section 95802(a)(43) is added to provide a definition for buttermilk.

Rationale for Section 95802 (a)(43)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(49)

New section 95802(a)(49) is added to provide a definition for canned non-tomato additive.

Rationale for Section 95802 (a)(49)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(57)

New section 95802(a)(57) is added to provide a definition for carbonation.

Rationale for Section 95802 (a)(57)

This new definition is necessary to.

Summary of Section 95802 (a)(59)

New section 95802(a)(59) is added to provide a definition for cheese.

Rationale for Section 95802 (a)(59)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(64)

New section 95802(a)(64) is added to provide a definition for complexity weighted barrel.

Rationale for Section 95802 (a)(64)

This new definition is necessary for the purposes of benchmarking and allowance allocation for petroleum refineries.

Summary of Section 95802 (a)(70)

New section 95802(a)(70) is added to provide a definition for compressed natural gas.

Rationale for Section 95802 (a)(70)

This new definition is necessary to clarify which entities are natural gas suppliers covered under the Cap-and-Trade Regulation. The definition here is slightly different from the definition of natural gas suppliers as covered under the Mandatory Reporting Regulation.

Summary of Section 95802 (a)(71)

New section 95802(a)(71) is added to provide a definition for concentrated milk.

Rationale for Section 95802 (a)(71)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(76)

New section 95802(a)(76) is added to provide a definition for corn chip.

Rationale for Section 95802 (a)(76)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(77)

New section 95802(a)(77) is added to provide a definition for corn curl.

Rationale for Section 95802 (a)(77)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(80)

New section 95802(a)(80) is added to provide a definition for cream.

Rationale for Section 95802 (a)(80)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(83)

New section 95802(a)(80) is added to provide a definition for crystal color concentrate.

Rationale for Section 95802 (a)(83)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(85)

Section 95802(a)(85) is modified to include importers importing electricity to meet CAISO's EIM and renumber to 114.

Rationale for Section 95802(a)(85)

This modification is necessary to capture and include EIM Participating Resource Scheduling Coordinators as importers of electricity into California.

Summary of Section 95802 (a)(86-90)

New sections 95802(a)(86-90) is added to provide definitions for the five products in the dehydrated flavors sector: dehydrated chili peppers, garlic, onion, parsley, and spinach.

Rationale for Section 95802 (a)(86-90)

These new definition is necessary to define the new products for benchmarking and allocation.

Summary of Section 95802 (a)(88)

Sections 95802(a)(88) are changed to modify the definition of emissions data report and renumber to 117.

Rationale for Section 95802 (a)(88)

This modification is necessary to be consistent with the Mandatory Reporting Regulation.

Summary of Section 95802 (a)(92)

New sections 95802(a)(92) is added to provide a definition for deproteinized whey.

Rationale for Section 95802 (a)(92)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(93)

New sections 95802(a)(93) is added to provide a definition for diced tomatoes.

Rationale for Section 95802 (a)(93)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(99)(c)

Section 95802(a)(99)(c) is change to modify the definition of facility with respect to onshore petroleum and natural gas production and renumber to 134.

Rationale for Section 95802 (a)(99)(c)

This modified definition is necessary to clarify that permanent pipeline equipment used to transfer emulsion to an onshore petroleum and natural gas facility is also considered part of that facility. In addition, this definition is also modified to clarify that a cogeneration plant is only considered part of the facility if the facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant.

Summary of Section 95802(a)(102).

Section 95802(a)(102) is added to provide a definition of a district heating facility.

Rationale for Section 95802(a)(102).

This definition is needed to define a type of entity that will be eligible to apply for a limited exemption of emissions during the first compliance period pursuant to section 95852(j).

Summary of Section 95802 (a)(103)

Sections 95802(a)(103) are modified to update the definition of First Point of Receipt to meet industry standards and renumber to 138.

Rationale for Section 95802 (a)(103)

This modification is necessary more accurately measure the amount of electricity that could be imported into California.

Summary of Section 95802 (a)(105)

New section 95802(a)(105) is added to provide a definition for ductile iron pipe.

Rationale for Section 95802 (a)(105)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(109)

New section 95802(a)(109) is added to provide a definition for early action reporting period.

Rationale for Section 95802 (a)(109)

This new definition is necessary to clarify what timeframe was being reference. The original Regulation contained a reference to Offset Project Data Report year which was somewhat ambiguous since the Offset Project data report is unique to compliance offset projects.

Summary of Section 95802(a)(114)

Section 95802(a)(114) is changed to modify the definition of fuel supplier and renumber to 150.

Rationale for Section 95802(a)(114)

This modification is necessary to include intrastate pipelines in the definition of fuel suppliers.

Summary of Section 95802(a)(119).

New section 95802(a)(119) is added to provide a definition for emulsion.

Rationale of Section 95802(a)(119).

This new definition is added to clarify the meaning of emulsion, which has been introduced in the definition of onshore petroleum and natural gas production facility, and to be consistent with MRR.

Summary of Section 95802(a)(121)

New section 95802(a)(121) is added to include reference to and identify CAISO's EIM market.

Rationale for Section 95802(a)(121)

This addition is necessary to capture electricity that is imported into California to fulfill CAISO's EIM requirements.

Summary of Section 95802(a)(122)

New section 95802(a)(122) is added to define EIM Participating Resource Scheduling Coordinators.

Rationale for 95802(a)(122)

This addition is necessary to identify the entity that is responsible for the compliance obligation when importing power into California to fulfill CAISO's EIM requirements.

Summary of Section 95802 (a)(128)

New section 95802(a)(128) is added to provide a definition for evaporated milk.

Rationale for Section 95802 (a)(128)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(129)

New section 95802(a)(129) is added to provide a definition for exchange.

Rationale for Section 95802 (a)(129)

This new definition is necessary to enable account representatives to classify the type of transaction agreement for which they are submitting a transfer request. Under the proposed amendments, the type of contract identifies the information the account representative must submit to complete the transfer request.

Summary of Section 95802 (a)(130)

New section 95802(a)(130) is added to provide a definition for "execution date."

Rationale for Section 95802 (a)(130)

This definition is needed to make proposed section 9592(a)(3)(B) clear to entities submitting a transfer request that they must submit the request within three days of an execution date, which is the date on or by which a transfer agreement requires compliance instruments to be transferred.

Summary of Section 95802(a)(137)

Section 95802(a)(137) is changed to modify the definition of imported electricity and renumber to 178.

Rationale for Section 95802(a)(137)

This modification is necessary to exclude electricity imported into California to meet emergency assistance requirements and to include electricity imported into California to meet CAISO's EIM requirements and to serve California's electricity load.

Summary of Section 95802 (a)(147)

New section 95802(a)(147) is added to provide a definition for freshwater diatomite filter aids.

Rationale for Section 95802 (a)(147)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(148)

New section 95802(a)(148) is added to provide a definition for fried potato chip.

Rationale for Section 95802 (a)(148)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(153)

New section 95802(a)(153) is added to provide a definition for futures.

Rationale for Section 95802 (a)(153)

This new definition is necessary to allow account representatives to submit all of the information needed to complete a transfer request. Entities that submit a transfer request as the result of a transaction on an exchange must identify the type of exchange-traded contract. The definition allows the account representative to enter the correct type.

Summary of Section 95802 (a)(159)

New section 95802(a)(159) is added to provide a definition for granulated refined sugar.

Rationale for Section 95802 (a)(159)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(160)

New section 95802(a)(160) is added to provide a definition for grape juice concentrate.

Rationale for Section 95802 (a)(160)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(168)

New section 95802(a)(168) is added to provide a definition for gypsum.

Rationale for Section 95802 (a)(168)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(173)

New section 95802(a)(173) is added to provide a definition for holding account.

Rationale for Section 95802 (a)(173)

This new definition is necessary to establish the equivalence between the term "holding account," which is used in the Regulation, and the term "general account," which is used in the tracking system (CITSS) in place of the term "holding account."

Summary of Section 95802 (a)(180)

New section 95802(a)(180) is added to provide a definition for Industrial Sector Legacy Contract Counterparty to identify the counter party of an operator of a legacy contract generator.

Rationale for Section 95802 (a)(180)

This new term and definition are necessary to identify the party for which allowances will be deducted, if allowances were allocated.

Summary of Section 95802 (a)(190)

New section 95802(a)(190) is added to provide a definition for lactose.

Rationale for Section 95802 (a)(190)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(191)

New section 95802(a)(191) is added to provide a definition for lager beer.

Rationale for Section 95802 (a)(191)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(192)

New section 95802(a)(192) is added to provide a definition for lead and lead alloys.

Rationale for Section 95802 (a)(192)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(195)

Section 95802(a)(195) is added to provide a definition for Legacy Contract to describe the type of contract that could be eligible for transition assistance.

Rationale for Section 95802(a)(195)

The new term and definition are necessary to limit the type of contracts for which allowances could be allocated.

Summary of Section 95802(a)(196)

Section 95802(a)(196) is added to provide a definition for Legacy Contract Emissions to define the emissions which are eligible for use in the calculation of allowances.

Rationale for Section 95802(a)(196)

This new term is necessary to limit the emissions included in the allowance calculation to just those that are a part of the legacy contract.

Summary of Section 95802(a)(197)

Section 95802(a)(197) is added to provide a definition for Legacy Contract Generator to identify the generator which produces the emissions.

Rationale for Section 95802(a)(197)

The new term and definition for "Legacy Contract Generator" is necessary to identify the emissions to be included in the calculation of allowances to the operator of the legacy contract.

Summary of Section 95802(a)(198)

Section 95802(a)(198) is added to provide a definition for Legacy Contract Qualified Thermal Output to describe the emissions due to the production of thermal energy.

Rationale for Section 95802(a)(198)

This new term and definition are necessary to include all of the sources of emissions that contribute to the thermal energy sold or provided to the Legacy Contract Counterparty.

Summary of Section 95802 (a)(204)

New section 95802(a)(204) is added to provide a definition for liquefied natural gas.

Rationale for Section 95802 (a)(204)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(206)

New section 95802(a)(206) is added to provide a definition for liquid color concentrate.

Rationale for Section 95802 (a)(206)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(215)

New section 95802(a)(215) is added to provide a definition for milk.

Rationale for Section 95802 (a)(215)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(223)

New section 95802(a)(223) is added to provide a definition for natural gas supplier.

Rationale for Section 95802 (a)(223)

This new definition is necessary to properly allocate allowances to the natural gas suppliers.

Summary of Section 95802(a)(226)

Section 95802(a)(226) is modified to fix a typographical error and renumber to 290.

Rationale for Section 95802(a)(226)

This modification is necessary to correct the spelling of electricity.

Summary of Section 95802 (a)(227)

New section 95802(a)(227) is added to provide a definition for non-thermal enhanced oil recovery.

Rationale for Section 95802 (a)(227)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(227)

Section 95802(a)(227) is changed to place bounds on the use of qualified positive offset verification statement and renumbered to 292.

Rationale for Section 95802(a)(227)

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

Summary of Section 95802 (a)(244)

New section 95802(a)(244) is added to provide a definition for over the counter.

Rationale for Section 95802 (a)(244)

This new definition is necessary to enable account representatives to classify the type of transaction agreement for which they are submitting a transfer request. Under the proposed amendments, the type of contract identifies the information the account representative must submit to complete the transfer request.

Summary of Section 95802(a)(246)

Section 95802(a)(X) is modified to update to the most current definition, as defined in the California Energy Commission's "Renewable Portfolio Standard Eligibility, 7th edition, Commission Guidebook, April, 2013; CEC-300-2013-005-ED7-CMF..

Rationale for Section 95802(a)(246)

The modification is necessary to maintain a consistent definition used by other agencies and industry.

Summary of Section 95802(a)(248)

Section 95802(a)(248) is changed to modify the definition of reporting period to clarify the length of an ODS project and renumber to 313.

Rationale for Section 95802(a)(248)

This modification is necessary to clarify that an ODS project can only have one reporting period. This is already in the Regulation text but is added to the definition for clarity.

Summary of Section 95802(a)(252).

Section 95802(a)(252) is modified to redefine resource shuffling to as a plan, scheme or artifice to reduce a First Deliverer's compliance obligation by substituting relatively lower emission electricity for higher emission electricity, and to exclude from the definition substitutions of electricity that occur pursuant to conditions listed in section 95852(b)(2)(A). This section was renumbered to 317

Rationale for Section 95802(a)(252).

This change is needed to clarify what kind of activity is considered resource shuffling, and to identify activities listed in section 95852(b)(2)(A) as being excluded from the definition of resource shuffling.

Summary of Section 95802 (a)(254)

New section 95802(a)(254) is added to provide a definition for pistachio.

Rationale for Section 95802 (a)(254)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(264)

New section 95802(a)(264) is added to provide a definition for poultry deli product.

Rationale for Section 95802 (a)(264)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(266)

New section 95802(a)(267) is added to provide a definition for powdered milk.

Rationale for Section 95802 (a)(266)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(267)

New section 95802(a)(266) is added to provide a definition for power contract.

Rationale for Section 95802 (a)(267)

This new definition is necessary to identify eligibility requirements so that importers of electricity are able to use the RPS adjustment.

Summary of Section 95802 (a)(268)

New section 95802(a)(268) is added to provide a definition for pretzel.

Rationale for Section 95802 (a)(268)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(271)

Section 95802(a)(271) is changed to modify the definition of supplier and renumber to 341.

Rationale for Section 95802(a)(271)

This modification is necessary to include operators of interstate pipelines.

Summary of Section 95802(a)(277)

Section 95802(a)(277) is changed to modify the definition of transfer and renumber to 352.

Rationale for Section 95802(a)(277)

This modification is necessary to remove serial number from the definition.

Summary of Section 95802 (a)(283)

New section 95802(a)(283) is added to provide a definition for protein meal.

Rationale for Section 95802 (a)(283)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(a)(284).

Section 95802(a)(284) is added to provide a definition of a public service facility.

Rationale for Section 95802(a)(284).

This definition is needed to define a type of entity that will be eligible for an allowance allocation pursuant to section 95870(d)(2) .

Summary of Section 95802(a)(285)

Section 95802(a)(285) is changed to modify the definition of verifier and renumber to 363.

Rationale for Section 95802 (a)(285)

This modification is necessary to define offset verifier to be interchangeable with verifier.

Summary of Section 95802(a)(287)

Section 95802(a)(287) is changed to modify the definition of voluntarily associated entity and renumber to 365.

Summary of Section 95802(a)(287).

Section 95802(a)(287) is added to provide a definition of a public wholesale water agency.

Rationale for Section 95802(a)(287).

This definition is needed to define a type of entity that will be eligible for an allowance allocation pursuant to section 95870(i).

Rationale for Section 95802 (287)

This modification is necessary to define general market participant to be interchangeable with voluntarily associated entity.

Summary of Section 95802(a)(287).

Section 95802(a)(287) is added to provide a definition of a public wholesale water agency.

Rationale for Section 95802(a)(287).

This definition is needed to define a type of entity that will be eligible to apply for allowance allocation pursuant to section 95870(i).

Summary of Section 95802(a)(294).

Section 95802(a)(294) is added to provide a definition of qualified thermal output.

Rationale for Section 95802(a)(294).

This definition is needed to clarify the kind of thermal output that will be used to determine the eligibility of a facility for a facility with a cogeneration unit or a district heating facility for a limited exemption for emissions associated with thermal energy production pursuant to section 95852(j).

Summary of Section 95802 (a)(321)

New section 95802(a)(321) is added to provide a definition for salt.

Rationale for Section 95802 (a)(321)

This new definition is necessary to assist in the definition of tomato soluble solids.

Summary of Section 95802 (a)(322)

New section 95802(a)(322) is added to provide a definition for seamless rolled ring.

Rationale for Section 95802 (a)(322)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(330)

New section 95802(a)(330) is added to provide a definition for skim milk.

Rationale for Section 95802 (a)(330)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(336)

New section 95802(a)(336) is added to provide a definition for spot.

Rationale for Section 95802 (a)(336)

This new definition is necessary to allow account representatives to submit all of the information needed to complete a transfer request. Entities that submit a transfer request as the result of a transaction on an exchange must identify the type of exchange-traded contract. The definition allows the account representative to enter the correct type.

Summary of Section 95802 (a)(337)

New section 95802(a)(337) is added to provide a definition for stand-alone-electricity generating facility.

Rationale for Section 95802 (a)(337)

This new definition is necessary to identify electricity generators that produce electricity only and do not provide steam.

Summary of Section 95802 (a)(342)

New section 95802(a)(342) is added to provide a definition for sweetened condensed milk.

Rationale for Section 95802 (a)(342)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(345)

New section 95802(a)(345) is added to provide a definition for thermal enhanced oil recovery.

Rationale for Section 95802 (a)(345)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(348)

New section 95802(a)(348) is added to provide a definition for tissue produced adjusted by water absorbency capacity.

Rationale for Section 95802 (a)(348)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(349)

New section 95802(a)(349) is added to provide a definition for tomato soluble solids.

Rationale for Section 95802 (a)(349)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(350)

New section 95802(a)(350) is added to provide a definition for tracking system.

Rationale for Section 95802 (a)(350)

This new definition is necessary to specifically include the tracking system that has been developed and deployed to help implement the program.

Summary of Section 95802 (a)(354)

New section 95802(a)(354) is added to provide a definition for transferred ARB Project.

Rationale for Section 95802 (a)(354)

This new definition is necessary because a new section was added to put in place requirements for offset projects transferring from one Offset Project Registry to another.

Summary of Section 95802(a)(356).

New section 95802(a)(356) is added to provide a definition for True-up allowance amount.

Rationale of Section 95802(a)(356).

This addition is needed to define the true-up allowance amount referenced in 95856(h)(1)(C), 95856(h)(2)(C) , and 95891.

Summary of Section 95802(a)(358).

Section 95802(a)(358) is added to provide a definition of a university covered entity.

Rationale for Section 95802(a)(358).

This definition is needed to identify a covered entity or opt-in covered entity that is a university eligible for an allowance allocation for transitional assistance pursuant to section 95870(f) with an allocation calculated pursuant to section 95891(e).

Summary of Section 95802 (a)(370)

Section 95802(a)(370) is added to provide a definition for Waste-to-Energy Facility in order to support the exemption from a compliance obligation during the first compliance period for Waste-to-Energy facilities.

Rationale for Section 95802 (a)(370)

This new definition is necessary to define the type of facility that will be exempted from a compliance obligation for the combustion of Municipal Solid Waste, in the first compliance period.

Summary of Section 95802 (a)(371)

New section 95802(a)(371) is added to provide a definition for water absorption capacity.

Rationale for Section 95802 (a)(371)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(372)

New section 95802(a)(372) is added to provide a definition for whey protein concentrate.

Rationale for Section 95802 (a)(372)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(373)

New section 95802(a)(373) is added to provide a definition for whole chicken and chicken parts.

Rationale for Section 95802 (a)(373)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802 (a)(374)

New section 95802(a)(374) is added to provide a definition for whole peeled tomatoes.

Rationale for Section 95802 (a)(374)

This new definition is necessary to define the new product for benchmarking and allocation.

Summary of Section 95802(b)

Section 95802(b) now includes two new acronyms and acronyms that were not needed were deleted.

Rationale for Section 95802(b)

Section 95802(b) was modified to provide clarity on acronyms used in the Regulation.

Subarticle 3: Applicability

Section 95811. Covered Entities.

Summary of Section 95811(a)(6).

Section 95811(a)(6) is modified to include lead producers.

Rationale for Section 95811(a)(6).

It is necessary to include lead production because the manufacturing process creates GHG emissions.

Summary of Section 95811(g)

New section 95811(g) is added to cover emissions associated with the use of liquefied natural gas.

Rationale for Section 95811(g).

This addition is necessary to include emissions from suppliers of liquefied natural gas because these fuels result in a significant share of the State's GHG emissions, when completely combusted.

Summary of Section 95811(g)(1).

New subsection (g)(1) is added to cover emissions associated with the use of liquefied natural gas produced at in-state facilities.

Rationale for Section 95811(g)(1).

This addition is necessary to include emissions from suppliers of liquefied natural gas because the GHG emissions from the combustion of this fuel are significant in the state.

Summary of Section 95811(g)(2).

New subsection (g)(2) is added to cover emissions associated with the use of imported liquefied natural gas.

Rationale for Section 95811(g)(2).

This addition is necessary to include emissions from suppliers of liquefied natural gas because the GHG emissions from the combustion of this fuel are significant in the state of California...

Summary of Section 95811(h).

Existing section 95811(g) was moved to new section 95811(h).

Rationale for Section 95811(h).

This change was necessary to accommodate new section 95811(g)

Section 95812. Inclusion Thresholds for Covered Entities.

Summary of Section 95812(b)

Section 95812(d) is modified to change the inclusion threshold years for a covered entity from 2009 through 2012 instead of 2009 through 2011.

Rationale of Section 95812(b)

This change is necessary to be consistent with the compliance obligation calculation in section 95853(a) and the definition of a covered entity.

Summary of Section 95812(d).

Section 95812(d) is modified to add entities specified in sections 95851(c) and (d) as entities that are classified as a covered entity as of January 1, 2015.

Rationale for Section 95812(d).

This change is needed to account for the phase in of the compliance obligation beginning in the second compliance period for operators of cogeneration facilities, district heating facilities, and eligible Waste-to-Energy facilities. This reflects the addition of a limited exemption of emissions from qualified thermal output pursuant to section 95852(j), and a change in the treatment of Waste-to Energy facilities pursuant to section 95852.2(c).

Summary of Section 95812(d)(1).

Subsection (d)(1) is changed to establish under what circumstances liquefied natural gas suppliers may trigger the inclusion threshold before coverage in 2015.

Rationale for Section 95812(d)(1).

This change is necessary to add liquefied natural gas to the inclusion threshold which captures emissions associated with liquefied natural gas suppliers with the largest amount of emissions without including small suppliers.

Summary of Section 95812(f)

New section 95812(f) is added to clarify the requirements for entities that have received a direct allocation of allowances but either shut down or cease operations prior to incurring a surrender obligation in that compliance period.

Rationale for Section 95812(f)

This addition is necessary 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 is provided for leakage minimization or transition assistance and assists an entity in meeting a surrender obligation in the compliance period for which the allocation was received. Any direct

allocation received for a compliance period that is not used to satisfy a surrender obligation is be returned to the State of California and auctioned.

Summary of Section 95812(f)(1)

New section 95812(f)(1) is added to state that within 30 days of facility closure, the facility operator must inform ARB in writing to either close its CITSS account, or remain in the program as a VAE.

Rationale for Section 95812(f)(1)

This addition is necessary to clarify the procedural requirements for covered entities in the event of a facility closure.

Summary of Section 95812(f)(2)

New section 95812(f)(2) is added to provide two options for entities that experience facility closure: to either fulfill the prorated compliance obligation for that compliance period, or surrender all allowances equivalent to the direct allocation less any allowances that were used to satisfy a surrender obligation.

Rationale for Section 95812(f)(2)

This addition is necessary to clarify that if a facility receives allocation, but has a greatly reduced compliance obligation, the direct allocation (minus any allowances used for a surrender obligation) would be returned to the State of California for auction.

Summary of Section 95812(f)(3)

New section 95812(f)(3) is added to clarify the requirements for purchased allowances left in a CITSS account after account closure.

Rationale for Section 95812(f)(3)

This addition is necessary to clarify that allowances purchased by the entity and left in a CITSS account upon account closure would be consigned to auction on behalf of the entity, pursuant to 95831(c)(3).

Summary of Section 95812(g)

New section 95812(g) was added to clarify that entities that have received a direct allocation of allowances but cease production must surrender allowances equivalent to

the amount directly allocated. This provision only holds for those entities without a true-up as the true-up would account for cease in production without a shutdown.

Rationale of Section 95812(g)

This section is necessary to ensure that companies that are not producing do not get allowances corresponding to years in which they did have any production. Direct industrial allowance allocation is for the purposes of minimizing leakage, therefore a company that is not producing though not shut down should not receive allocation for the corresponding years. In most cases, a true-up would account for changes in production but this section is necessary any sectors which may not have a true-up.

Section 95813. Opt-In Covered Entities.

Summary of Section 95813(b).

Section 95813(b) is modified to include the date that an opt-in participant must register with the Executive Officer.

Rationale for Section 95813(b).

The change in this provision is necessary to allow the opt-in covered entity to meet the April 4 Mandatory Reporting Regulation reporting deadline to be eligible for free allocation.

Summary of Section 95813(c).

New section 95813(c) is added to allow opt-in covered entities to rescind their opt-in request and provide an effective date.

Rationale for Section 95813(c).

The change permits a facility opting in to the Cap-and-Trade Program to go through the full reporting and verification process to understand its compliance costs and use this information to update its decision to opt into the program.

Summary of Section 95813(d).

Section 95813(d) is modified to include the first reporting deadline an opt-in covered entity must meet.

Rationale for Section 95813(d).

This change is necessary to explicitly state the first reporting deadline an opt-in covered entity is required to meet. By requiring an opt-in covered entity to comply with MRR, opt-in covered entities may be eligible to receive free allocation pursuant to 95870 for the opt-in year.

Section 95814. Voluntarily Associated Entities and Other Registered Participants.

Summary of Section 95814(a)(3).

New section 95814(a)(3) is added to require that individual VAEs with a job related to the Cap-and-Trade program provide a letter from their employer guaranteeing that there is no conflict of interest.

Rationale for Section 95814(a)(3).

This new section is needed to ensure employers are aware if their employees choose to participate in the Cap-and-Trade Program, especially if the employee has access to carbon- market information through his or her daily job.

Summary of Section 95814(a)(4).

New section 95814(a)(4) is added to address individuals already in the tracking system who meet the criteria of 95814(a)(3).

Rationale for Section 95814(a)(4).

This addition is necessary to prevent conflicts of interest among individuals already registered in the tracking system.

Summary of Section 95814(a)(6)

New section 95814(a)(6) is added to prohibit individuals disclosed by registered entities pursuant to section 95830(c) from registering as Voluntarily Associated Entities (VAE). These individuals identified through the registration process are those that would have knowledge of the registered entity's compliance instrument transactions and holdings.

Rationale for Section 95814(a)(6)

The change is needed because individuals eligible to register as VAE would be able to take actions on behalf of their individual accounts based on their knowledge of the registered entity's actions. These individuals could also undermine ARB's market

surveillance by undertaking coordinated actions with the registered entity. This addition is necessary to prevent insider trading and conflicts of interest.

Summary of Section 95814(b)(1-5).

New sections 95814(b)(1-5) are added to specify more entities that may not hold compliance instruments. This section originally stated these entities could be Registered Participants, however in other parts of the Regulation, they were actually prohibited from holding compliance instruments.

Rationale for Section 95814(b)(1-5).

Each of these types of entities has a particular risk for insider trading based on their work for covered entities or offset project implementation that ARB needs to prevent. This addition is also necessary to prevent conflicts of interest.

Section 95821. Compliance Instruments Issued by Approved Programs.

Summary of Section 95821(f)

New section 95821(f)(1) is added to allow the use of Early Reduction Credits issued by Québec as compliance instruments that may be used to meet compliance obligations. Adding this section required minor formatting changes to existing sections 95821(d) and (e).

Rationale for Section 95821(f)

This provision is necessary because the other provisions in the section do not specify that Early Reduction Credits issued by Québec can be used to meet compliance obligations.

Summary of Section 95821(f)(1)

New section 95821(f)(1) is added to allow the use of Early Reduction Credits issued by Québec as compliance instruments that may be used to meet compliance obligations.

Rationale for Section 95821(f)(1)

This provision is necessary because the other provisions in the section do not specify that Early Reduction Credits issued by Québec can be used to meet compliance obligations.

Section 95830. Registration with ARB.

Summary of Section 95830(b)(1)

Section 98830(b)(1) was modified to explicitly tie the reporting entity in MRR to the requirement for registration in the tracking system.

Rationale for Section 95830(b)(1)

This addition is necessary to ensure enforceability on the entity subject to the MRR that meets the Cap-and-Trade inclusion threshold and clarify it must be the same entity to register for an account in the tracking system.

Summary of Section 95830(b)(2) and (3)

Section 98830(b)(2) and (3) were modified to explicitly add that registration refers to the tracking system.

Rationale for Section 95830(b)(2) and (3)

This clarification is needed as all registration requirements are being implemented through the tracking system.

Summary of Section 95830(b)(4)

New section 98830(b)(4) was added to require all offset project operators for projects located on tribal lands to have a waiver of sovereign immunity in place prior to registration for an account in the tracking system.

Summary of Section 95830(c)(1)(H)

Section 95830(c)(1)(H) was modified to explicitly state all information required under section 95833 is due at the time of registration.

Rationale for Section 95830(c)(1)(H)

This modification was needed to ensure staff had all information available at the time of registration prior to approval of any accounts in the tracking system.

Summary of Section 95830(c)(1)(I)

New section 95830(c)(1)(I) is added to require entities registering or registered with ARB to disclose names and contact 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.

Rationale for Section 95830(c)(1)(I)

Existing disclosures of individuals by the registering entity are designed to allow ARB to determine whether two different registered entities are coordinating their actions through by individuals participating in the decision making of both entities. The existing requirements focus mainly on those in a decision-making capacity, either as officers, owners, or account representatives. The new text would add disclosure requirements for individuals who gain knowledge of a registered entity's transaction strategy through their work as employees of the entities.

Summary of Section 95830(c)(1)(J)

New section 95830(c)(1)(J) is added to require that entities that employ auction bidding advisors or consultants for cap-and-trade activities to disclose the information required under new section 95923 as part of the registration process. The new text would add disclosure requirements for individuals who gain knowledge of a registered entity's compliance and transaction strategy through their work as consultants. These individuals may serve as consultants for multiple registered entities, giving them extensive knowledge of confidential information.

Rationale for Section 95830(c)(1)(J)

The new text would add disclosure requirements for individuals who gain knowledge of a registered entity's transaction strategy through their work as consultants. ARB needs to be aware of these consultant-client relationships to monitor for collusive activity.

Summary of Section 95830(c)(7)(A)-(D)

New section 85830(c)(7) was added to require individuals to first register for an account in the tracking system prior to having any access to entity accounts in the tracking system. This section places similar requirements on individual user accounts as entity accounts, such as only having one user account in the tracking system.

Rationale for Section 95830(c)(7)(A)-(D)

This section is needed to support implementation of the tracking system registration requirements.

Summary of Section 95830(c)(8)(A)-(E)

New section 95830(c)(8) was added to clarify the circumstances under which the Executive Officer may deny an individual's registration in the tracking system.

Rationale for Section 95830(c)(8)(A)-(E)

This section is needed to ensure program participants understand which requirements, if not met, would result in an application denial. The Executive Officer can only approve individual user accounts that meet the full requirements of the Regulation.

Summary of Section 95830(d)(1)

Section 95830(d)(1) is modified to add opt-in covered entities to the registration deadlines found in this section.

Rationale for Section 95830(d)(1).

This addition is necessary to harmonize the registration deadlines of opt-in covered entities and other covered entities.

Summary of Section 95830(d)(1)(B)

Section 95830(d)(1)(B) was modified for consistency with section 95812 on which year's emissions count towards applicability of the Regulation.

Rationale for Section 95830(d)(1)(B)

This modification was needed to provide consistency with the definition of a covered entity and clarity throughout the Regulation.

Summary of Section 95830(d)(2).

Section 95830(d)(2) is deleted and this registration deadline was merged with the deadline for covered entities found in 95830(d)(1).

Rationale for Section 95830(d)(2).

A specific registration deadline for opt-in covered entities is no longer needed. Instead, opt-in covered entities are required to comply with registration deadlines for covered entities pursuant to section 95830(d)(1).

Summary of Section 95830(f)(1)

Section 95830(f)(1) is modified to contain a new requirement that entities that are already registered and have submitted information to satisfy section 95830(c) must update the information within 30 days of a change to the requirements becoming effective. The existing requirement to update the information submitted within 10 days of a change to information already submitted is rewritten for clarity.

Rationale for Section 95830(f)(1)

The change is needed to set a deadline for registered entities to submit new information within 30 days of a regulatory change to the requirements becoming effective. The change to the current requirement for updating of information is needed for clarity.

Summary of Section 95830(g)(1)

Section 95830(g)(1) was modified to include additional information to be submitted as part of registration to be treated as confidential by ARB.

Rationale for Section 95830(g)(1)

This modification was needed to protect information about internal staff within an entity that must be disclosed as part of registration by the entity. The treatment of this data as confidential is consistent with existing provisions to treat similar data as confidential.

Summary of Section 95830(i)(1-8)

New section 95830(i) was added to include the process for how changes in ownership of covered facilities or entities are addressed.

Rationale for Section 95830(i)(1-8)

This section is needed to implement and support a clear process for how ARB and the account holders will take steps for ownership changes. These requirements were developed in response to stakeholder concerns about clear roles for the two parties involved in the ownership change.

Section 95831. Account Types.

Summary of Section 95831(a)(5)

Section 95831(a)(5) is modified to correct a reference to section 95814(a)(1)(C).

Rationale for Section 95831(a)(5)

The change is needed to clarify that an exchange clearing holding account will only be created for entities that qualify as a voluntarily associated entity by operating an exchange clearing service for an exchange regulated by the CFTC pursuant to section 95814(a)(1)(C).

Summary for Section 95831(a)(6)

The section authorizes the Executive Officer to create a Limited Exemption Holding Account when an entity qualifies for direct allocation pursuant to section 95870.

Rationale for Section 95831(a)(6)

The change is needed because the allocation pursuant to section 95870 will provide eligible entities with allowances that have a vintage date making them a future vintage. In some instances the allocation could place an entity in violation of a future vintage holding limit. The Limited Exemption Holding Account will be a temporary holding area for the allowances until January 1 of their vintage year.

Summary for Section 95831(a)(6)(A)

The section authorizes the Executive Officer to place allowances which are allocated pursuant to section 95870 in a year prior to the vintage year of the allowances into the Limited Exemption Holding Account.

Rationale for Section 95831(a)(6)(A)

The provision is needed to specify when the Executive Officer will transfer allowances to the Limited Exemption Holding Account and what is the source of the allowances.

Summary for Section 95831(a)(6)(B)

The section prohibits entities from transferring allowances from their Limited Exemption Holding Account.

Rationale for Section 95831(a)(6)(B)

The provision is needed because transferring the allowances to a holding or compliance account could lead to an accidental violation of the holding limit.

Summary for Section 95831(a)(6)(C)

The section authorizes the Executive Officer to remove allowances from the Limited Exemption Holding Account if the entity does not have sufficient compliance instruments in its compliance account, up to the amount of allowances received as part of the true-up.

Rationale for Section 95831(a)(6)(C)

The provision is needed so that the "true-up" allowances are available for triennial compliance surrender if needed.

Summary for Section 95831(a)(6)(D)

This provision requires the allowances received by a publicly-owned utility in its limited exemption holding account will be transferred on January 1 of the vintage year of the allowances to the compliance accounts designated in the determination made by the entity.

Rationale for Section 95831(a)(6)(D)

The provision is needed is needed to ensure that allowances are not transferred to an entity's compliance account before they will count as "current" vintage allowances. This will minimize the chances of a violation of the holding limit.

Summary for Section 95831(a)(6)(E)

This provision requires the allowances received by a natural gas supplier in its limited exemption holding account will be transferred on January 1 of the vintage year of the allowances to the compliance accounts designated in the determination made by the entity.

Rationale for Section 95831(a)(6)(E)

The provision is needed is needed to ensure that allowances are not transferred to an entity's compliance account before they will count as "current" vintage allowances. This will minimize the chances of a violation of the holding limit.

Summary for Section 95831(a)(6)(F)

This provision requires the allowances received by an entity pursuant to section 95870(e), (f), and (g) will be transferred to the entity's holding account on January 1 of the vintage year of the allowances.

Rationale for Section 95831(a)(6)(F)

The provision is needed is needed to ensure that allowances are not transferred to an entity's holding account before they will count as "current" vintage allowances. This will minimize the chances of a violation of the holding limit.

Summary of Section 95831(b)(3)

Existing section 95831(b)(3) is modified to eliminate the reference to serial numbers of compliance instruments retired.

Rationale for Section 95831(b)(3)

This change is needed because serial numbers will not be referenced in the retirement process.

Summary of Section 95831(c)(3).

Section 95831(c)(3) is added to specify that allowances needed to satisfy a compliance obligation from a closed account would be drawn first from the entity's Compliance Account and, if needed, from the entity's Holding Account. Section 95831(c)(4) is renumbered following the addition of Section 95831(c)(3).

Rationale for Section 95831(c)(3).

This change is needed to specify the order in which accounts will be accessed to satisfy an entity's compliance obligation if the entity's account is closed.

Section 95832. Designation of Representatives and Agents.

Summary of Section 95832(a)(6)

Section 95832(a)(6) was modified to include language to ensure consistency with other attestations in this subarticle.

Rationale for Section 95832(a)(6)

This modification was needed to ensure consistency and enforceability of the attestations made by account representatives.

Section 95833. Disclosure of Corporate Associations.

Summary of Section 95833(a)(1).

Section 95833(a)(1) is modified to specify that corporate associations in the Regulation are not limited to entities registered in the Cap-and-Trade program.

Rationale for Section 95833(a)(1).

This change is necessary to provide clarity to market participants regarding which corporate associations should be disclosed to ARB. This is a clarification on an existing requirement and not a new requirement or change in policy.

Summary of Section 95833(a)(1)(F).

Section 95833(a)(1)(F) is modified to include limited liability corporations in the criteria for determining corporate associations.

Rationale for Section 95833(a)(1)(F).

This change is necessary to close a loophole which allowed limited liability corporations to avoid being declared corporate associates of other entities.

Summary of Section 95833(a)(2).

Section 95833(a)(2) is modified to specify that corporate associations in the Regulation are not limited to entities registered in the Cap-and-Trade program.

Rationale for Section 95833(a)(2).

This change is necessary to provide clarity to market participants regarding which corporate associations should be disclosed to ARB. This is a clarification on an existing requirement and not a new requirement or change in policy.

Summary of Section 95833(a)(2)(F).

Section 95833(a)(2)(F) is modified to include limited liability corporations in the criteria for determining corporate associations.

Rationale for Section 95833(a)(2)(F).

This change is necessary to close a loophole which allowed limited liability corporations to avoid being declared corporate associates of other entities..

Summary of Section 95833(a)(3).

Section 95833(a)(3) is modified to specify that corporate associations in the Regulation are not limited to entities registered in the Cap-and-Trade program.

Rationale for Section 95833(a)(3).

This change is necessary to provide clarity to market participants regarding which corporate associations should be disclosed to ARB. This is a clarification on an existing requirement and not a new requirement or change in policy.

Summary of Section 95833(a)(4)(c).

Section 95833(a)(4)(c) is modified to include limited liability corporations as a type of relationship that must be considered when reviewing for a corporate association..

Rationale for Section 95833(a)(4)(c).

This change is needed to close a loophole that did not address limited liability corporations.

Summary of Section 95833(e)(3)(C)

Section 95833(e)(3)(C) was modified to clarify when the purchase and holding limits must be specified if directly associated entities opt-out of account consolidation.

Rationale for Section 95833(e)(3)(C)

This modification was needed to provide additional clarity to entities on when the purchase and holding limit decision needed to be provided to ARB.

Summary of Section 95833(f)(3).

Section 95833(f)(3) is modified to delete the deadline date by which directly associated entities must opt-out of consolidation.

Rationale for Section 95833(f)(3).

This change is necessary to allow entities to opt-out of consolidation post-2012. The Regulation as currently written would not allow for entities to change their current opt out decisions.

Summary of Section 95833(f)(3)(C)(1)

New section 95833(f)(3)(C)(1) is added to specify that the opt-out confirmation must include the holding limit split between entities opting out.

Rationale for Section 95833(f)(3)(C)(1)

New section 95833(f)(3)(C)(1) is necessary to clarify that the opt-out process includes specifying how holding limits will be shared between entities.

Summary of Section 95833(f)(3)(C)(2)

New section 95833(f)(3)(C)(2) is added to specify that the opt-out confirmation must include the purchase limit split between entities opting out.

Rationale for Section 95833(f)(3)(C)(2)

New section 95833(f)(3)(C)(2) is necessary to clarify that the opt-out process includes specifying how purchase limits will be shared between entities.

Summary of Section 95833(f)(6).

New section 95833(f)(6) is added to establish that directly associated entities may only change their opt-out decision once a year.

Rationale for Section 95833(f)(6).

This change is needed to ensure stability in account structures in CITSS to enable oversight and ease for auction participation by limiting the number of times significant information related to auction participation can change due to changes in account consolidation.

Summary of Section 95833(f)(7)

New section 95833(f)(7) was added to required 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.

Rationale for Section 95833(f)(7)

This section was added because two covered entities with the same account representatives have the potential to coordinate on market related decisions even if they do not have a direct corporate association. This provision treats the two entities as one for the purposes of the purchase and holding limits just as any directly associated group of entities would be treated where you would expect some coordination on market related decisions.

Section 95834. Know-Your Customer Requirements.

Summary of Section 95834(c)(2)

New section 95834(c)(2) was added to allow for ARB to verify the identity of an account registrant on a two-year schedule.

Rationale for Section 95834(c)(2)

This section was needed to allow ARB additional audit and oversight of tracking system users to ensure integrity in the program.

Section 95841.1 Voluntary Renewable Electricity.

Summary of Section 95841.1(a)

Section 95841.1(a) is modified to clarify that if RECs are created, they must represent the same generation included in the information provided in the allowance retirement request, and those same RECs must be retired before the allowance retirement request is submitted to ARB.

Rationale for Section 95841.1(a)

The additional language is necessary to ensure the underlying electricity was delivered to California during the same allowance budget year from which allowances are retired. The additional language also allows WREGIS time to create the REC.

Summary of Section 95841.1(b)(1)(A)

Section 95841.1(b)(1)(A) is modified to clarify the electricity delivery requirements.

Rationale for Section 95841.1(b)(1)(A)

The additional language is necessary to clarify the electricity must be directly delivered to California.

Summary of Sections 95841.1(b)(1)(B)

Section 95841.1(b)(1)(B) is modified to update the reference to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs.

Rationale for Sections 95841.1(b)(1)(B)

This modification is necessary to reference the most current edition of the guidelines, which is incorporated by reference in the Regulation.

Summary of 95841.1(b)(1)(C)

Section 95841.1(b)(1)(C) is modified to update the reference to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs, which is incorporated by reference in the Regulation.

Rationale for 95841.1(b)(1)(C)

This modification is necessary to reference the most current edition of the guidelines.

Summary of Section 95841.1 (b)(2)(A)

Section 95841.1(b)(2)(A) is modified to update the reference to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs.

Rationale for 95841.1 (b)(2)(A)

This modification is necessary to reference the most current edition of the guidelines, which is incorporated by reference in the Regulation.

Summary of Section 95841.1(b)(2)(D)

Section 95841.1(b)(2)(D) is modified to specify that a WREGIS Renewable Energy Credit (REC) Retirement report meets the requirement for evidence RECs were retired.

Rationale for Section 95841.1(b)(2)(D)

The modification clarifies the reference to the title of the WREGIS compliance report, which will satisfy the requirement to provide evidence the REC was retired, if a REC was created as part of the transaction.

Summary of Section 95841.1(b)(3)(A)

Section 95841.1(b)(3)(A) is modified to update the reference to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs.

Rationale for Section (b)(3)(A)

This modification is necessary to reference the most current edition of the guidelines, which is incorporated by reference.

Summary of Section 95841.1(b)(3)(D)

Section 95841.1(b)(3)(D) is modified to specify that a WREGIS Renewable Energy Credit (REC) Retirement report meets the requirement for evidence RECs were retired.

Rationale for Section 95841.1(b)(3)(D)

The modification clarifies the reference to the title of the WREGIS compliance report, which will satisfy the requirement to provide evidence the REC was retired, if a REC was created as part of the transaction.

Section 95851. Phase-in of Compliance Obligation for Covered Entities.

Summary of Section 95851(a)

Section 95851(a) was modified to fix an incorrect reference.

Rationale for Section 95851(a)

This modification was needed for accuracy and clarity in the Regulation.

Summary of Section 95851(b).

Subsection (b) is modified to identify that liquefied natural gas suppliers have a compliance obligation in the second compliance period beginning in 2015.

Rationale for Section 95851(b).

This modification is necessary to include liquefied natural gas beginning in 2015 because reporting requirements were added effective 2013. This additional time will give these liquefied natural gas suppliers enough time to collect and verify their emissions data and provide it to ARB.

Summary of Section 95851(c).

Section 95851(c) is modified to include cogeneration facilities and district heating facilities that have been approved for a limited exemption of emissions pursuant to section 95852(j) among the entities that have a compliance obligation beginning with the second compliance period.

Rationale for Section 95851(c).

Facilities that have installed cogeneration units to increase efficiency and would be below the threshold for a compliance obligation if they did not produce both electricity and qualified thermal output would be disadvantaged compared to similar facilities without cogeneration during the first compliance period when compliance costs are not passed through by natural gas suppliers. Similarly, district heating facilities, that can provide multiple buildings with thermal energy, would be disadvantaged compared to buildings that have their own, less efficient, boilers and chillers. By exempting emissions from production of qualified thermal output, these facilities will fall below the threshold. Once natural gas suppliers are covered entities beginning in the second compliance period, all entities will face compliance costs directly or indirectly in natural gas prices. To avoid a disadvantage for more efficient systems during the first compliance period, these facilities will not have a compliance obligation until the second compliance period.

Summary of Section 95851(d).

Section 95851(c) is modified to include waste to energy facilities that have been approved for a limited exemption of emissions pursuant to section 95852(k) among the entities that have a compliance obligation beginning with the second compliance period.

Rationale for Section 95851(d).

This new section was needed to provide waste to energy facilities entities with an exemption from a compliance obligation in the first compliance period to have a compliance obligation in the second compliance period.

Section 95852. Emission Categories Used to Calculate Compliance Obligations.

Summary of Section 95852(b)(2).

Section 95852(b)(2) is modified to delete the requirement that First Deliverers attest in writing that they have not engaged in resource shuffling (attestation in section 95852(b)(2)(A)), and that they are subject to all regulatory requirements and enforcement mechanisms of the Cap and Trade program (attestation in section 95852(b)(2)(B)).

Rationale for Section 95852(b)(2).

Staff was concerned that requiring the attestations in this section had the potential to negatively affect western electricity markets. To address this concern, the attestation requirement was deleted, while the prohibition against resource shuffling continues in force.

Summary of Section 95852(b)(2)(A).

New section 95852(b)(2)(A) is added to replace the pre-existing attestation requirement with a list of substitutions of lower emission electricity deliveries for higher emission electricity deliveries that do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A).

Many stakeholders asked that ARB provide additional clarity as to what kind of substitutions of electricity could be considered "safe harbors" that would not be deemed resource shuffling. The list of "safe harbors" in this section provides additional clarity.

Summary of Section 95852(b)(2)(A)(1).

New section 95852(b)(2)(A)(1) is added to state that electricity deliveries caused by the procurement of Renewable Portfolio Standard (RPS) electricity is not resource shuffling.

Rationale for Section 95852(b)(2)(A)(1).

EDUs are required to increase the percentage of RPS electricity procured to serve load to 33 percent of retail sales by 2020. This requirement may result in the need to substitute zero emission electricity for higher emission electricity. Because the RPS is a complementary measure that reduces GHG emissions, and because it is a requirement for EDUs, a substitution under this section is not resource shuffling.

Summary of Section 95852(b)(2)(A)(2).

New section 95852(b)(2)(A)(2) is added to state that electricity deliveries made to comply with state of federal laws or regulations is not resource shuffling.

Rationale for Section 95852(b)(2)(A)(2).

When a first deliverer substitutes lower emission electricity for higher emission electricity to comply with state of federal laws or regulations, the purpose is not to reduce compliance obligations and such substitution is not resource shuffling.

Summary of Section 95852(b)(2)(A)(3).

New section 95852(b)(2)(A)(3) is added to state that electricity deliveries made to comply with requirements related to maintaining electricity grid reliability, such as North American Electric Reliability Corporation (NERC) Reliability Standards, and Reliability Coordinator directives, including provision of electricity between entities to alleviate grid emergencies, do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(3).

When a first deliverer substitutes lower emission electricity for higher emission electricity when required for grid reliability or emergency situations, these substitutions cannot constitute resource shuffling because they are binding requirements and such substitutions are not done to reduce compliance obligations.

Summary of Section 95852(b)(2)(A)(4).

New section 95852(b)(2)(A)(4) is added to clarify that electricity deliveries made to comply with a judicially approved settlement or the settlement of a transaction dispute pursuant to contract terms for reasons other than reducing compliance obligations is not resource shuffling.

Rationale for Section 95852(b)(2)(A)(4).

Settlements considered in this section are binding upon the parties. Therefore, substitutions involving electricity deliveries pursuant to such settlements do not constitute resource shuffling if the first deliverer's reason for the settlement is not to reduce compliance obligations.

Summary of Section 95852(b)(2)(A)(5).

New section 95852(b)(2)(A)(5) is added to clarify that electricity deliveries that substitute for power previously supplied by a specified source that has been retired do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(5).

If a relatively higher emitting resource is retired, substitution of lower emission electricity is consistent with the goal of reducing emissions, and such substitution is not considered resource shuffling.

Summary of Section 95852(b)(2)(A)(6).

New section 95852(b)(2)(A)(6) is added to clarify that electricity deliveries that substitute for deliveries that have been discontinued due to contract termination or divestiture of resources for reasons other than reducing compliance obligations do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(6).

Contract termination may occur for reasons outside the control of a first deliverer party to the contract. In addition, first deliverers may divest themselves of emitting resources for reasons other than reducing compliance obligations, such as regulatory requirements or to alleviate conditions in which they have surplus electricity. Therefore substitutions covered in this section do not constitute resource shuffling.

Summary of Section 95852(b)(2)(A)(7).

New section 95852(b)(2)(A)(7) is added to clarify that electricity deliveries that are necessary due to early termination of a contract for, or full or partial divestiture of, resources subject to Emission Performance Standard (EPS) rules established by CEC and the CPUC do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(7).

State energy policy, as reflected in the EPS rules established pursuant to California Public Utilities Code section 8340, encourage California utilities to pursue early divestment of resources that do not meet the EPS, in part to protect the State's ratepayers from potential future costs associated with high emission power plants. This section was necessary to be consistent with State policy reflected in the EPS rules.

Summary of Section 95852(b)(2)(A)(8).

New section 95852(b)(2)(A)(8) is added to clarify that electricity deliveries that are necessary due to expiration of a contract do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(8).

When a contract expires, a First Deliver will likely have to use other resources, which may be lower in emissions, to replace the electricity lost due to contract expiration. Furthermore, it is not the intent of this Regulation to require entities to attempt to renegotiate new contracts for electricity from the same resource with which a contract has expired. Therefore, substitutions covered in this section do not constitute resource shuffling.

Summary of Section 95852(b)(2)(A)(9).

New section 95852(b)(2)(A)(9) is added to include a safe harbor for electricity deliveries pursuant to short term contracts with terms of no more than 12 months that are linked to selling off or assigning a contract for power from a power plant that does not meet the EPS with which a California EDU has a contract or ownership, when the transactions are based on economic decisions including congestion costs but excluding implicit and explicit GHG costs. This section also states that in evaluating these short term deliveries, ARB will consider levels of past sales and purchases from similar resources, among other factors, to judge whether the activity is resource shuffling.

Rationale for Section 95852(b)(2)(A)(9).

Several stakeholders were concerned that ordinary business practices for trading electricity could be inhibited by uncertainty over whether they would be considered resource shuffling. This modification was needed to provide a safe harbor for ordinary transactions when they are not linked to selling or assigning electricity from power plants that do not meet the EPS. When such short term transactions are made based on economic decisions including congestion costs or other factors not related to emissions, they will not constitute resource shuffling. However, if the economic decisions include consideration of GHG costs, then these transactions may be part of a resources shuffling plan, scheme or artifice to reduce compliance obligations.

Summary of Section 95852(b)(2)(A)(10).

New section 95852(b)(2)(A)(10) is added to include a safe harbor for short term transactions and contracts for electricity delivery with terms of no more than 12 months that result from an economic bid or self-schedule that clears the CAISO day-ahead or

real time market, for specified or unspecified power, based on economic decisions that include implicit and explicit GHG costs and congestion costs. Such transactions are excluded from this safe harbor if they are linked to the selling off 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 an ownership share, unless the transaction is included under paragraphs 11, 12 or 13 below.

Rationale for Section 95852(b)(2)(A)(10).

For short term transactions resulting from an economic bid or self-schedule, GHG costs must be included in the bid and in the market award process. These bids or schedules are likely to result in dispatch of lower emission electricity and therefore may reduce overall GHG emissions. It is not the intent of this Regulation to inhibit these kinds of transactions in the CAISO markets. However, if these transactions are linked to selling off or assigning a contract for power from a power plant that does not meet the EPS and with which a California EDU has a contract or ownership share, such transactions are likely to involve resource shuffling unless they fall under the safe harbors provided in sections 95852(b)(2)(A)(11, 12, and 13).

Summary of Section 95852(b)(2)(A)(11).

New section 95852(b)(2)(A)(11) is added to clarify that electricity deliveries that are necessary due to operational emergencies or transmission constraints, including constraints caused by the inability to secure transmission rights, or transmission curtailments do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(11).

When a First Deliverer makes deliveries, or changes in deliveries, due to emergencies or transmission constraints, the First Deliverer is acting based on circumstances not under its control. Substitutions involving these deliveries are not done to reduce compliance obligations and do not constitute resource shuffling.

Summary of Section 95852(b)(2)(A)(12).

New section 95852(b)(2)(A)(12) is added to clarify that electricity deliveries that are necessary due because a First Deliverer has more than enough electricity to meet demand due to requirements that the First Deliverer take generation from specific resources , including "must-take" or "must-run" contract provisions do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(12).

Under the terms of some contracts, a First Deliverer may be required to take generation from a specific generating unit. Because these are binding requirements on the First Deliverer, such electricity deliveries are not resource shuffling.

Summary of Section 95852(b)(2)(A)(13).

New section 95852(b)(2)(A)(13) is added to include clarify that electricity deliveries that are required to make up for transmission losses do not constitute resource shuffling.

Rationale for Section 95852(b)(2)(A)(13).

Under some contracts, the counterparty to a First Deliverer may provide electricity to make up for transmission laws from resources chosen by the counterparty that are not identified in advance. Because the first deliverer has no control over what is delivered for this purpose, these deliveries are not resource shuffling.

Rationale for Section 95852(b)(2)(B).

The proposed amendment provides additional clarity as to particular kinds of substitutions of electricity that would constitute resource shuffling and are not considered part of the "safe harbors" of section 95852(b)(2)(A).

Summary of Section 95852(b)(2)(B)(1).

New section 95852(b)(2)(B)(1) is added to identify as resource shuffling the substitution of lower emission electricity to replace electricity generated at a high emission power plant that does not meet California's EPS, and procured by the First Deliverer under a long-term contract or ownership arrangement, when the substitution is made to reduce compliance obligation.

Rationale for Section 95852(b)(2)(B(1).

Certain first deliverers have long-term contracts for, or ownership of, a share of a high emission power plant that does not meet the EPS. If the first deliverer substitutes lower emission electricity for electricity from such a power plant, the electricity from the high emission plant would be sold elsewhere. In this case, there would be an apparent reduction in California emissions, paired with an increase in emission for electricity consumed outside of California. This kind of substitution is one form of resource shuffling and is prohibited.

Summary of Section 95852(b)(2)(B)(2).

New section 95852(b)(2)(B)(2) is added to identify as resource shuffling the assignment of a contract for high emission electricity specified in section 95852(b)(2)(B)(1) to a third party to reduce the compliance obligation of the assigning party.

Rationale for Section 95852(b)(2)(B)(2).

The substitution of lower emission electricity for electricity procured from a high emission power plant that has been contractually assigned to another party would have the same result as a substitution identified in section 95852(b)(2)(B)(1). There would be no real reduction in emissions, and such a substitution would be prohibited as resource shuffling.

Summary of Section 95852(b)(3)

Section 95852(b)(3) is modified to include the use of an asset controlling supplier emission factor. This section is also modified to remove the reference to delivered electricity less than the default factor.

Rationale for Section 95852(b)(3)

This modification is necessary because these entities are considered specified sources of electricity. The deletion is necessary because imported electricity imported by an electricity importer from a specified source could be greater than the default emissions factor, if it is procured from a resource that emits GHG greater than the default emissions factor.

Summary of Section 95852(b)(3)(D)

Section 95852(b)(3)(D) is modified to delete the requirement to retire RECs but instead to require the reporting of the serial numbers of retired RECs to MRR.

Rationale for Section 95852(b)(3)(D)

This change is necessary to apply consistent requirements to importers and in-state generators. The reporting of REC serial numbers is necessary to maintain environmental integrity by publicly providing information on the RECs associated with specified imports.

Summary of Section 95852(b)(4)

Section 95852(b)(4) is modified to delete the reference to electricity that is imported.

Rationale for Section 95852(b)(4)

This modification is necessary because for the RPS adjustment the renewable electricity procured is never imported into California. The adjustment is given for the , replacement electricity which is imported.

Summary of Section 95852(b)(4)(A)

Section 95852(b)(A) is modified to delete the term "either."

Rationale for Section 95852(b)(4)(A)

This deletion is necessary because this term is redundant. The term "or" is already included in the choices provided in 92852(b)(A)(1).

Summary of Section 95852(b)(4)(A)(1)

Section 95852(b)(4)(A)(1) is modified to specify that RECs procured must be created as a result of the electricity generated from the same eligible renewable electricity generating facility as identified in the contract.

Rationale for Section 95852(b)(4)(A)(1)

This modification is necessary to clarify the RECs for the RPS adjustment must be from the same eligible renewable electricity generating facility as the electricity that is procured.

Summary of Section 95852(b)(4)(A)(2)

Section 95852(b)(4)(A)(2) is modified to specify that the contract must be to procure both the electricity and the RECs.

Rationale for Section 95852(b)(4)(A)(2)

This modification is necessary to ensure the procurement of both the electricity and the RECs from the same eligible generator, and that the contract to procure that electricity and associated RECs is on behalf of an entity that is required to meet California's RPS requirement.

Summary of Section 95852(b)(4)(B)

Section 95852(b)(4)(B) is modified to more explicitly state what must happen to the RECs associated with an RPS adjustment.

Rationale for Section 95852(b)(4)(B)

This modification is necessary to provide specific direction on what actually has to happen to the REC to be able to take the RPS adjustment.

Summary of Section 95852(b)(4)(F)

Section 95852(b)(4)(F) is modified to clarify the vintage of RECs that are eligible to be used for the adjustment.

Rationale for Section 95852(b)(4)(F)

This modification is necessary to clarify only RECs generated on or after the commencement of the compliance requirement of the Regulation will be acceptable to be used for an RPS adjustment.

Summary of Section 95852(c)(2)

Section 95852(c)(2) was modified to provide multiple sources of data for calculating the emissions from natural gas delivered to covered entities and to clarify how missing data and adverse verification statements will be dealt with.

Rationale for Section 95852(c)(2)

Changes were necessary to ensure adequate data is available for calculating emissions from natural gas delivered to covered entities and to explain what to do in cases of missing data and adverse verification statements.

Summary of Section 95852(e)

Subsection (e) is modified to change Natural Gas Liquids to Liquefied Petroleum Gas.

Rationale for Section 95852(e)

This modification is necessary apply the more precise and consistent terminology of liquefied petroleum gas throughout the Regulation.

Summary of Section 95852(g)

Existing section 95852(g) is modified to refer to the definition of Carbon Dioxide Supplier instead of referring to the section numbers for the definition.

Rationale for Section 95852(g)

This change is necessary to explicitly refer to the correct definition and not the section number for the definition as each regulation amendment requires the renumbering of the section numbers in the definitions subarticle.

Summary of Section 95852(i)

Subsection (i) is modified to add a reference to a new fuel supplier, liquefied natural gas suppliers.

Rationale for Section 95852(i)

This change is necessary to accommodate the addition of liquefied natural gas fuel suppliers as covered entities.

Summary of Section 95852(j).

New section 95852(j) is added to provide for a limited exemption of emissions from the production of qualified thermal output during the first compliance period for a district heating facility or a cogeneration facility that meets the requirements of this section. Additionally, such emissions shall not have a compliance obligation and shall not count toward the inclusion threshold of section 95812(c)(1) during the first compliance period.

Rationale for Section 95852(j).

Facilities that have annual emissions above the inclusion threshold of 25,000 $MTCO_2e$ only because they have installed cogeneration to produce both electricity and thermal energy to increase overall efficiency would be disadvantaged compared to similar facilities have boilers for thermal energy production and remain below the threshold because they do not produce electricity. Similarly, during the first compliance period, a district heating facility above the threshold that provides steam, thermal energy, or chilled water to many buildings more efficiently than a single building with its own boilers and chillers can produce these outputs would have a compliance obligation not faced by individual buildings below the threshold. However, beginning with the second compliance period when natural gas providers are covered entities, compliance costs will begin to be passed through to natural gas users through increased prices. Adding section 95852(j) to exempt emissions associated with qualified thermal output for these facilities during the first compliance period removes undesired disadvantages for these facilities.

Summary of Section 95852(j)(1).

New section 95852(j)(1) is added to list the two conditions that must be met by a cogeneration facility to apply for the limited exemption of emissions from the production of qualified thermal output. The facility must have greenhouse gas emissions related to qualified thermal output below 25,000 metric tons of CO_2e and the remaining emissions must also be below 25,000 metric tons of CO_2e

Rationale for Section 95852(j)(1).

This section is needed to explain the conditions that must be met for a cogeneration facility to qualify for the limited exemption.

Summary of Section 95852(j)(1)(A).

New section 95852(j)(1)(A) is added to provide the equation calculating a cogeneration facility's annual emissions associated with the production of qualified thermal output, which must be below the 25,000 MTCO2e compliance threshold for the facility to be eligible for the limited exemption. This section also defines the terms of the equation.

Rationale for Section 95852(j)(1)(A).

To qualify for the limited exemption, a cogeneration facility must have annual emissions associated with qualified thermal output below the threshold. This section provides the methodology to determine if this condition is met.

Summary of Section 95852(j)(1)(B).

New section 95852(j)(1)(B) is added to provide the equation calculating a cogeneration facility's remaining annual after subtracting emissions associated with qualified thermal output, which must be below 25,000 MTCO2e for the facility to be eligible for the limited exemption. This section also defines the terms of the equation.

Rationale for Section 95852(j)(1)(B).

To qualify for the limited exemption, a cogeneration facility's remaining emissions, after subtracting emissions associated with qualified thermal output, must be below the threshold. This section provides the methodology to determine if this condition is met.

Summary of Section 95852(j)(2).

New section 95852(j)(2) is added to state the requirement for a district heating facility to apply for the limited exemption of emissions from the production of qualified thermal

output: the emissions associated with energy distributed to each single facility must not exceed the compliance threshold.

This section provides the equation for calculating emissions associated with qualified thermal output provided to each single facility served by a district heating facility and to define the terms in the equation.

Rationale for Section 95852(j)(2).

A district heating facility that has emissions above the compliance threshold of 25,000 $MTCO_2e$ because it serves multiple buildings would face a disadvantage during the first compliance period compared to buildings below the threshold that have their own boilers and chillers. However, if a single building's emissions ere above the compliance obligation, it would face a compliance obligation. Therefore, if a district energy provides services associated with more than 25,000 $MTCO_2e$ to a single building, it is reasonable for it to have a compliance obligation.

This section is needed to explain the conditions that must be met for a district heating facility to qualify for the limited exemption.

Summary of Section 95852(j)(3).

New section 95852(j)(3) is added to state that the Executive Officer may use date reported to ARB under MRR for data years 2008-2013 to determine a facility's eligibility for the limited exemption.

Rationale for Section 95852(j)(3).

This section is needed to provide for ARB's use of data reported to MRR in determining a facility's eligibility for the limited exemption.

Summary of Section 95852(j)(4).

New section 95852(j)(4) is added to provide that a facility with a cogeneration unit or a district heating facility must apply to the Executive Officer by September 15, 2014 for the limited exemption of emissions from the production of qualified thermal output, and must provide data and an attestation. Section 95852(j)(4)(A) requires the applicant to provide annual qualified thermal output from 2008 to 2013; section 95852(j)(4)(B) requires a district heating facility to provide data on the qualified thermal output provided to each single facility; and section 95852(j)(4)(C) requires the applicant to attest under penalty of perjury that the information submitted is true, accurate, and complete. Section

95852(j)(4)(D) is added to require the applicant to register with ARB. Section 95852(j)(4)(E) is added to require the applicant to report and verify their emissions.

Rationale for Section 95852(j)(4).

This section is needed to explain the requirements and set the date for a cogeneration facility's or district energy facility's application for a limited exemption. Section 95852(j)(4)(A) requires the provision of annual qualified thermal output from 2008 to 2013 which is needed because thermal output reported pursuant to MRR for data years through 2012 did not include sufficient information to determine if such thermal output met the new definition in this Regulation for qualified thermal output. Section 95852(j)(4)(B) is needed to obtain data to determine if a district heating facility qualifies for the limited exemption. Section 95852(j)(4)(C) is needed to ensure that the determination of eligibility for the limited exemption is based on data that is true, accurate, and complete. Section 95852(j)(4)(D) is necessary to have the operators obtain a Compliance Instrument Tracking System Service (CITSS) account into which allowances can be deposited. Section 95852(j)(4)(E) is needed to be able to determine the number of allowances to place into the entity's compliance account

Summary of Section 95852(k)

New section 95852 (k) is modified to provide a limited exemption for the first compliance period for waste-to-energy facilities that meet the prescribed requirements.

Rationale of Section 95852(k)

This change is necessary to exempt the waste-to-energy facilities while ARB coordinates with Cal/Recycle and other stakeholders to characterize lifecycle emissions reduction opportunities for different options for handling solid waste, including recycling, remanufacturing of recovered materials in state, composting and anaerobic digestion, waste-to-energy facilities, landfilling, and the treatment of biomass as directed by Resolution 11-32. The study will help staff identify and propose regulatory amendments, as appropriate, so that AB 32 implementation, including the Cap-and-Trade Regulation, aligns with statewide waste management goals, provides equitable treatment to all sectors involved in waste handling, and considers the best available information.

Summary of Section 95852(k)(1)

New section 95852.2(k)(1) is added to require the operator of a Waste-to-Energy facility to register with ARB.

Rationale for Section 95852(k)(1)

This new provision is necessary to have the operators obtain a Compliance Instrument Tracking System Service (CITSS) account into which allowances can be deposited.

Summary of Section 95852(k)(2)

New section 95852(k)(2) is added to require the waste-to-energy facilities to report and verify their emissions.

Rationale for Section 95852(k)(2)

This new section is needed to be able to determine the number of allowances to place into the entity's compliance account.

Summary of Section 95852(k)(3)

New Section 95852(k)(3) is added to require the electricity generated by the combustion of the municipal solid waste be used for retail sale.

Rationale for Section 95852(k)(3)

This new provision is necessary to insure the electricity generated by the combustion of the municipal solid waste is not to meet the facilities internal load.

Summary of Section 95852(k)(4)

New section 95852(k)(3) is added to require the facility to have an existing approved air pollution control district permit for their waste-to-energy operations.

Rationale for Section 95852(k)(4)

This new provision is needed to prevent new plants from taking advantage of the exemption until the study to determine a comprehensive approach for the appropriate treatment of municipal solid waste under the Cap-and-Trade program is complete.

Summary of Section 95852(k)(5)

New section 95852(k)(5) is added to describe the eligible fuel that can be combusted in order for the operator to take the exemption.

Rationale for Section 95852(k)(5)

This provision is necessary to limit the type fuel that is able to be combusted at the facility to Municipal Solid Waste.

Summary of Section 95852(k)(6).

New section 95852(k)(6) is added to provide for the retirement of allowances equal to the quantity of emissions without a compliance obligation due to the limited exemption of emissions pursuant to new section 95852(j).

Rationale for Section 95852(k)(6).

The emissions from facilities eligible for the limited exemption of emissions pursuant to new section 95852(j) were included in ARB's forecast used for setting the annual caps on emissions. Because the limited exemption removes these emissions from the cap during the first compliance period, it is necessary to retire an equivalent quantity of emissions to preserve the environmental integrity of the cap.

Summary of Section 95852(l)

Subsection (l) is added to identify that a supplier of liquefied natural gas has a compliance obligation for every metric ton of CO_2e of GHG emissions that would result from full combustion or oxidation of all fuel sold, distributed, or otherwise transferred for consumption in California.

Rationale for Section 95852(l).

This addition is necessary to identify the emissions categories used to calculate compliance obligations for suppliers of liquefied natural gas.

Section 95852.1.1. Eligibility Requirements for Biomass-Derived Fuels.

Summary of Section 95852.1.1(a)(2).

Subsection (a)(2) is changed to require that purchasers of biomass-derived fuel not under contract prior to January 1, 2012 be the first purchasers of the contracted fuel.

Rational for Section 95852.1.1(a)(2).

This modifications is necessary to remove an unintentional paradox that prevented new sources of biomass-derived fuel under contract prior to January 1, 2012 from being eligible for an avoided compliance obligation.

Summary of Section 95852.1.1(a)(2)(B).

Subsection (a)(2)(B) is modified to require that in order for biomass-derived fuel from an existing source be eligible for an avoided compliance obligation, the biomass derived fuel must be vented or destroyed without producing electricity or heat for three years or since commencement of fuel recovery, whichever is shorter.

Rational for Section 95852.1.1(a)(2)(B)

This modification is necessary to prevent leakage of emissions outside California due to switching a contract for biomass-derived fuel from out-of-state to a California entity.

Summary of Section 95852.1.1(a)(3)(B).

Subsection (a)(3)(B) is changed to require that in order for biomass-derived fuel from an existing instate source be eligible for an avoided compliance obligation, the biomass derived fuel must be destroyed without producing electricity or heat for three years or since commencement of fuel recovery, whichever is shorter.

Rational for Section 95852.1.1(a)(3)(B).

This change is necessary to prevent leakage of emissions outside California due to switching a contract for biomass-derived fuel from out-of-state to a California entity.

Summary of Section 95852.1.1(a)(4).

Section 95852.1.1(a)(3) is changed to include instate production of biomass derived fuel as eligible to avoid a compliance obligation when sold offsite and is moved to new section 95852.1.1(a)(4).

Rationale for Section 95852.1.1(a)(4).

This change is necessary to include offsite sale of instate biomass-derived fuel production as eligible to avoid a compliance obligation.

Summary of Section 95852.1.1(b).

Subsection (b) is changed to tie the global warming potential of methane to the global warming potential listed in the MRR and clarify that any emission reductions credited in the Low Carbon Fuel Standard Carbon Intensity must be accounted for when determining if the project is eligible to receive offsets.

Rationale for Section 95852.1.1(b)

This modification is necessary to tie the global warming potential of methane to the MRR to be consistent across both regulations. Modifications are also necessary to

clarify that any emission reductions credited in the Low Carbon Fuel Standard Carbon Intensity must be accounted for when calculating the total credits from methane emission reductions.

Section 95852.2. Emissions without a Compliance Obligation.

Summary of Section 95852.2(b)(10).

Subsection (b)(10) is modified to identify fugitive emissions from equipment leaks that do not hold a compliance obligation.

Rationale for Section 95852.2(b)(10).

This change is necessary to correct the reference for fugitive emissions from equipment leaks estimated using leak detection and leaker emission factors, and add the exemption from a compliance obligation for emissions estimated using population counts and emission factors.

Summary of Section 95852.2(b)(11)

New section 95852.2(b)(11) is added to clarify that offshore oil and natural gas production facilities will remain exempt from having a compliance obligation under the Cap-and-Trade Program.

Rationale for Section 95852.2(b)(11)

This change is necessary to ensure consistency between the Cap-and-Trade and MRR regulations.

Summary for Section 95852.2(b)(12)

This section was changed to add in enhanced oil recovery to ensure that exports or imports for enhanced oil recovery are still subject to a compliance obligation.

Rationale for Section 95852.2(b)(12)

This change is necessary to include carbon dioxide exported or imported for enhanced oil recovery along with geologic sequestration as still subject to a compliance obligation unless there is a Board approved quantification methodology to account for those emissions pursuant to section 95852(g)

Summary for Section 95852.2(b)(13)

New section 95852.2(b)(12) is added to exempt CO_2 used in the carbonation process during sugar production from a compliance obligation.

Rational for Section 95852.2(b)(13)

This addition is necessary to exempt the CO_2 from lime, which is bubbled through the limed juice producing calcium carbonate crystals during the sugar production process. Based on available technical information, staff believes no CO_2 is released to the atmosphere as a result of this process.

Summary of Section 95852.2 (c)(1)

Section 95852.2(c)(1) is modified to broaden the types of facilities not subject to a compliance obligation under the Cap-and-Trade Program. Section 95852.2(c)(1) specifically removes the expiration date for the exemption for military facilities.

Rational for Section 95852.2 (c)(1)

Staff believes it is appropriate to exempt military facilities as this sector has other mechanisms already in place that have the potential to achieve equivalent reductions through a broad-based approach that encompasses sources that are below applicability thresholds for both the Mandatory Reporting Regulation and the Cap-and-Trade Program. The military sector is subject to Presidential Executive Order 13514 Strategic Sustainability Performance Plan (Sustainability Plan) that includes a 34 percent reduction in Scope 1 and Scope 2 GHG emissions, 13.5 percent reduction in Scope 3 GHG emissions, a 37.5 percent reduction in building energy intensity, a 20 percent renewable energy standard, and a 30 percent reduction in fossil fuel consumption for vehicle fleets.

Section 95853. Calculation of Covered Entity's Triennial Compliance Obligation.

Summary of Section 95853(e).

Section 95853(e) is deleted to remove the allowance allocation multiplier for new entrants.

Rationale for Section 95853(e).

The allowance allocation multiplier for new entrants is no longer needed with the addition of true-up allowances pursuant to 95891. True-up allowances and the associated borrowing pursuant to sections 95856(h)(1)(C) and 95856(h)(2)(C) allow

new entrants to receive appropriate levels of allowances for all compliance dates. New entrants may receive additional allowances through the calculation of true-up allowances depending on eligibility, historical production, and allocation.

Section 95856. Timely Surrender of Compliance Instruments by a Covered Entity.

Summary of Section 95856(b)(2)(A)

Section 95856(b)(2)(A) is modified to specify that all allowances purchased through an Allowance Price Containment Reserve sale are eligible for immediate compliance.

Rationale for Section 95856(b)(2)(A)

This change is necessary to allow all allowances purchased from an Allowance Price Containment Reserve sale to be surrendered for immediate compliance.

Summary of Section 95856(b)(2)(C)

New section 95856(b)(2)(C) is added to state that true-up allowances are valid compliance instruments for surrender if they are issued from an allowance budget year within or before the year for which an annual compliance obligation is calculated or the last year of a compliance period for which a triennial compliance obligation is calculated.

Rationale for Section 95856(b)(2)(C)

This provision is necessary because it specifies when true-up allowances can be used to fulfill compliance obligations.

Summary of Section 95856(c)

Section 95856(c) was modified to provide clarity on which instruments can be used for annual and triennial surrender obligations.

Rationale for Section 95856(c)

This modification was needed for clarity on which allowance types were eligible.

Summary of Section 95856(d)(1)

Section 95856(d)(1) is modified to specify the exact deadline time for surrender of annual compliance obligations.

Rationale for Section 95856(d)(1)

This provision is necessary because it provides participants with a specific deadline that will support implementation of this requirement in the tracking system.

Summary of Section 95856(d)(2)

Section 95856(d)(2) is modified to specify the exact deadline time for surrender of annual compliance obligations.

Rationale for Section 95856(d)(2)

This provision is necessary because it provides participants with a specific deadline that will support implementation of this requirement in the tracking system.

Summary of Section 95856(f)(1)

Section 95856(f)(1) is modified to specify the exact deadline time for surrender of triennial compliance obligations.

Rationale for Section 95856(f)(1)

This provision is necessary because it provides participants with a specific deadline that will support implementation of this requirement in the tracking system.

Summary of Section 95856(g)(1)

Section 95856(g)(1)(A) is modified to specify that fulfillment of the annual compliance obligation will be determined by evaluating the quantity and type of compliance instruments in entities' compliance accounts. The section also allows the "true-up" allowances contained in an entity's Limited Exemption Holding Account to be used for compliance with the annual compliance obligation.

Rationale for Section 95856(g)(1)

This provision is necessary because it clarifies that the Executive Officer will evaluate the quantity and type of compliance instruments at the annual surrender event, rather than retire the compliance instruments from the Compliance Account. Therefore, stakeholder concern about not estimating the quantify 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 is mitigated. The provision is also needed to reflect the creation of the Limited Exemption

Holding Account, which ensures that "true-up" allowances will count towards compliance.

Summary of Section 95856(g)(2)(A)

Section 95856(g)(2)(A) is modified to specify that fulfillment of the triennial compliance obligation will be determined by retiring the quantity and type of compliance instruments in entities' compliance accounts.

Rationale for Section 95856(g)(2)(A)

This provision is necessary because it clarifies that the Executive Officer will retire the quantity and type of compliance instruments from the Compliance Account at the triennial surrender event.

Summary of Section 95856(g)(2)(B)

Section 95856(g)(2)(B) is modified to specify that programs linked to California will be informed of the compliance instrument retirement.

Rationale for Section 95856(g)(2)(B)

This provision is necessary because it clarifies that information regarding compliance instrument retirement in California is shared among linked programs.

Summary of Section 95856(h)(1)(A)

New section 95856(h)(1)(A) is added to specify that offset credits will be the first type of compliance instrument to be considered in the Compliance Account by the Executive Officer for fulfillment of the annual compliance obligation, with older vintage offsets being considered first.

Rationale for Section 95856(h)(1)(A)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be considered by the Executive Officer for compliance with the annual surrender event. Offsets are retired first as they are considered to be the lowest cost compliance instrument that can be used for compliance.

Summary of Section 95856(h)(1)(B)

New section 95856(h)(1)(B) is added to specify that allowances purchased from the Allowance Price Containment Reserve and Québec's Emission Reduction Credits will be the second types of compliance instruments to be considered in the Compliance Account by the Executive Officer for fulfillment of the annual compliance obligation.

Rationale for Section 95856(h)(1)(B)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be considered by the Executive Officer for compliance with the annual surrender event. These compliance instruments are placed second as they have no associated vintage. And, if the account were closed for some reason, it would be difficult to consign allowances without vintages to an auction. The APCR allowances are "last resort" instrument and presumably, there would be no other allowances with vintages that would be eligible for use for that compliance surrender event.

Summary of Section 95856(h)(1)(C)

New section 95856(h)(1)(C) is added to specify that allowances from California and linked jurisdictions will be the third type of compliance instrument to be considered in the Compliance Account by the Executive Officer for fulfillment of the annual compliance obligation based on earliest vintage first.

Rationale for Section 95856(h)(1)(C)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be considered by the Executive Officer for compliance with the annual surrender event. These compliance instruments are placed third as they could potentially be consigned to auction, if needed. And, the order from earlier to newest aligns with the policy of banking allowances for compliance use, but no borrowing of allowances from future vintages for meeting a compliance obligation.

Summary of Section 95856(h)(1)(D)

New section 95856(h)(1)(D) is added to specify that true-up allowances will be the fourth type of compliance instrument to be considered in the Compliance Account by the Executive Officer for fulfillment of the annual compliance obligation.

Rationale for Section 95856(h)(1)(D)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be considered by the Executive Officer for compliance with the annual surrender event. These compliance instruments are placed last in the order or eligibility for use for a compliance obligation because this process allows for a very limited borrowing of future vintage allowances in situations where an entity did not have any of the other eligible compliance instruments for that compliance surrender event.

Summary for Section 95856(h)(2)

The provision authorizes the Executive Officer to retire allowances directly from an entity's compliance account and Limited Exemption Holding Account to satisfy an entity's triennial compliance obligation.

Rationale for Section 95856(h)(2)

The provision is needed to ensure that "true-up" allowances as well as allowances in the compliance account will count towards compliance.

Summary of Section 95856(h)(2)(A)

New section 95856(h)(2)(A) is added to specify that offset credits will be the first type of compliance instrument to be retired from the Compliance Account by the Executive Officer for fulfillment of the triennial compliance obligation, with older vintage offsets being retired first.

Rationale for Section 95856(h)(2)(A)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be retired by the Executive Officer for compliance with the triennial surrender event. Offsets are retired first as they are considered to be the lowest cost compliance instrument that can be used for compliance.

Summary of Section 95856(h)(2)(B)

New section 95856(h)(2)(B) is added to specify that allowances purchased from the Allowance Price Containment Reserve will be the second type of compliance instrument to be retired from the Compliance Account by the Executive Officer for fulfillment of the triennial compliance obligation.

Rationale for Section 95856(h)(2)(B)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be retired by the Executive Officer for compliance with the triennial surrender event. These compliance instruments are placed second as they have no associated vintage. And, if the account were closed for some reason, it would be difficult to consign allowances without vintages to an auction. The APCR allowances are "last resort" instrument and presumably, there would be no other allowances with vintages that would be eligible for use for that compliance surrender event.

Summary of Section 95856(h)(2)(C)

New section 95856(h)(2)(C) is added to specify that allowances from California and linked jurisdictions will be the third type of compliance instrument to be retired from the Compliance Account by the Executive Officer for fulfillment of the triennial compliance obligation.

Rationale for Section 95856(h)(2)(C)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be retired by the Executive Officer for compliance with the triennial surrender event. These compliance instruments are placed third as they could potentially be consigned to auction, if needed. And, the order from earlier to newest aligns with the policy of banking allowances for compliance use, but no borrowing of allowances from future vintages for meeting a compliance obligation.

Summary of Section 95856(h)(2)(D)

New section 95856(h)(2)(D) is added to specify that true-up allowances will be the fourth type of compliance instrument to be retired from the Compliance Account by the Executive Officer for fulfillment of the triennial compliance obligation.

Rationale for Section 95856(h)(2)(D)

This provision is necessary because it provides participants with details regarding the order in which compliance instruments will be retired by the Executive Officer for compliance with the triennial surrender event. These compliance instruments are placed last in the order or eligibility for use for a compliance obligation because this process allows for a very limited borrowing of future vintage allowances in situations where an entity did not have any of the other eligible compliance instruments for that compliance surrender event.

Summary of Section 95856(h)(3)

New section 95856(h)(3) is added to specify that true-up allowances cannot be used to fulfill current compliance obligations by entities that are not eligible to receive true-up allowances.

Rationale for Section 95856(h)(3)

This provision is necessary because it clarifies that only entities eligible to receive true up allowances can fulfill their compliance obligations through the use of current year vintage allowances or allowances allocated immediately before the current surrender deadline.

Section 95857. Untimely Surrender of Compliance Instruments by a Covered Entity.

Summary of Section 95857(d)(1)(B)

Section 95857(d)(1)(B) was modified to keep the one fourth of untimely surrender compliance instruments in an entity's compliance account until the triennial surrender date at which time, they would be retired.

Rational for Section 95857(d)(1)(B)

This modification was needed to align the process for untimely surrender with the new proposed process to not retire any instruments from the compliance account until the time of triennial surrender.

Section 95870. Disposition of Allowances.

Summary of Section 95870(b)(1)

Section 95870(b)(1) is modified to specify that allowances designed for Advance Auction are eligible for sale through the Allowance Price Containment Reserve sale immediately preceding the compliance obligation on November 1.

Rationale for Section 95870(b)(1)

This change is necessary in fulfillment of Board Resolution 12-51 to ensure that the allowance price does not exceed the highest price tier of the Reserve.

Summary of Section 95870(b)(2)

Section 95870(b)(2) is modified to specify that Advance Auction allowances not sold through the Reserve sale are sold at auction pursuant to Section 95910.

Rationale for Section 95870(b)(2)

This subsection is necessary to clarify the disposition of allowances designated for Advance Auction.

Summary of Section 95870(b)(3)

New section 95870(b)(3) is amended to update the treatment of auction proceeds.

Rationale for Section 95870(b)(3)

This change is required in accordance with Government Code Section 16428.8.

Summary of Section 95870(d)

Section 95870(d) was added to provide a title for the section that now incorporates two subsections.

Rationale for Section 95870(d)

This change was necessary to provide a title for a section that now includes two subsections. This allows electricity related allocation to be contained in the same section.

Summary of Section 95870(d)(1)

Section 95870(d)(1) was modified to change the allocation date for electrical distribution utilities

Rationale of section 95870(d)(1)

This change was necessary to be consistent with the allocation date for all allocation.

Summary of Section 95870(d)(2).

Section 95870(d)(2) is added to provide for the allocation of allowances to a public wholesale water agency. Allocations for calendar years 2013 to 2015 are made on or before October 15, 2014 from the budget year 2015. Allowances will be placed in each

eligible agency's compliance account on or before October 15 of each calendar year from 2014 to 2019 from the 2015 to 2020 annual allowance budgets.

Rationale for Section 95870(d)(2).

This section is needed to provide the schedule for allocation and to state the budget years used for allocations for public wholesale water agencies pursuant to new section 95895. These allocations are necessary to mitigate the cost impact to ratepayers associated with the compliance obligations for electricity used to convey water.

Summary of Section 95870(e)

Section 95870(e) was modified to specify the new holding account into which allowances will be placed for allocation and then transferred to the holding account on the first business day when the allocated allowance vintage is the current calendar year.

Rationale for Section 95870(e)

This modification is needed to prevent allocated allowances from counting against the holding limit until they are of current vintage.

Summary of Section 95870(e)(1)

Section 95870(e)(1) was modified to specify the new date when allowance allocation would occur.

Rationale for Section 95870(e)(1)

This modification is needed to allow for covered entities to have their true-up allowances in their accounts at least two weeks prior to the surrender obligation being due.

Summary of Section 95870(e)(4)

New section 95870(e)(4) is added to provide an adjustment to the compliance obligation for an industrial entity.

Rationale for Section 95870(e)(4)

This new section is necessary to be able to adjust the allowance allocation to the industrial entity if they are also a Legacy Contract Counterparty.

Summary of Section 95870(e)(5).

Section 95870(e)(5) is added to provide for the allocation of allowances into the compliance accounts and holding accounts of facilities that did not receive an industrial allocation in calendar years 2013 or 2014, and are approved by the Executive Officer for a limited exemption of emissions from the production of qualified thermal output. On October 15, 2014, the Executive Officer will place allowances equal to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years, less the amount of allowances in the facility's compliance account on October 14, 2014, in the facility's compliance account, and will place allowances equal to the amount in its compliance account into the facility's holding account. An amount of allowances equivalent to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years will be retired by ARB according to the surrender date in section 95856.

Rationale for Section 95870(e)(5).

This section is needed to allow ARB to place allowances into the compliance and holding accounts of a facility that did not receive any industrial allocation and has been approved for a limited exemption of emissions to account for the facility's emissions that do not have a compliance obligation in the first compliance period, so that they can be retired in order to maintain the environmental integrity of the cap. It provides for allocation of allowances into the facility's holding account to replace allowances the facility placed in its compliance account and no longer needs to comply due to the approval of its limited exemption.

Summary of Section 95870(e)(6).

Section 95870(e)(6) is added to require a facility that received an industrial allocation in calendar years 2013 or 2014 and is approved for the limited exemption of emissions pursuant to new section 95852(j) to place allowances equal to the amount received into its compliance account so they can be retired to account for the facility's emissions during 2013 and 2014 that do not have a compliance obligation. This section states that if the amount of allowances equal to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years exceeds the amount received in calendar years 2013 and 2014, the Executive Officer will place the difference in the facility's compliance account, and if the allowances received in calendar years 2013 and 2014 exceeds the amount the facility's reported, verified, and covered emissions for 2013 and 2014, the facility will have its future allocations reduced by the excess allowances received. ARB will reduce future allocations by subtracting from the facility's budget year 2015 allocation, and from subsequent budget year allocations if necessary, until

the total subtracted equals the amount by which the 2013 and 2014 allocations exceeds the reported, verified, and covered emissions for those years. This section also states that the Executive Officer shall retire allowances equivalent to the 2013 and 2014 covered emissions according to section 95856.

Rationale for Section 95870(e)(6).

If a facility received an industrial allocation in 2013 or 2014 and has subsequently been approved for a limited exemption of emissions pursuant to new section 95852(j), the amount of the 2013 and 2014 industrial allocation must be retired to preserve the environmental integrity of the cap, and to ensure that the facility is not provided allowances for emissions that do not have a compliance obligation. This section is needed to implement this change, tot require the facility to make allowances available in its compliance account for retirement, to account for any differences between the amounts allocated in 2013 and 2014 compared to the reported, verified and covered emissions during those year. Finally, this section is needed to provide for the retirement by ARB of the allowances equivalent to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years according to the surrender date in section 95856.

Summary of Section 95870(f).

New section 95870(f) is added to provide for the allocation of allowances to university covered entities and public service facilities. Allocations for calendar years 2013 to 2015 are made on or before October 15, 2014 from the budget year 2015. Allocations for calendar years 2015 to 2019 are made from the 2016 to 2020 annual allowance budgets on or before October 15 of each calendar year.

Rationale for Section 95870(f).

This section is needed to provide the schedule for allocation and to state the budget years used for allocations for university covered entities and public service facilities that are eligible for allocations pursuant to new section 95890(d).

Summary of Section 95870(g)

New section 95870(g) is added to allow the Executive Officer to transfer allowances to the eligible operator of the Legacy Contract Generator.

Rationale for Section 95870(g)

This new section is necessary to provide the operator of the legacy contract generator with allowances for the purpose of transition assistance, if they meet the eligibility requirements in new section 95894.

Summary of Section 95870(h)

New section 95870(f) is added to provide for the allocation of allowances to natural gas suppliers on or before October 15th of each calendar year.

Rationale of Section 95870(h)

This section is needed to provide the schedule for allocation for natural gas suppliers that are eligible for allocations pursuant to new section 95890(f).

Summary of Section 95870(j)(1)

Section 95870(i)(1) is modified to make up to 10% of the allowances from each vintage that are not allocated to the Allowance Price Containment Reserve, eligible for sale in the Reserve.

Rationale for Section 95870(j)(1)

This change is needed to increase the quantity of allowances sold through the Reserve pursuant to Board Resolution 12-51.

Summary of Section 95870(j)(2)

Section 95870(i)(2) is modified to update the treatment of auction proceeds and fix an incorrect reference.

Rational for Section 95870(j)(2)

This change is required to reflect the treatment of auction proceeds pursuant to Government Code Section 16428.8.

Summary of Section 95870 Table 8-1: Industry Assistance.

Existing Table 8-1 is modified to change the columns under the assistance factor such that for the period 2015 - 2017 all entries will read "100%" and for the period of 2018 - 2019, the portion of the column corresponding to the medium leakage risk classification

will read "75%" and the portion of the column corresponding to low leakage risk will read "50%".

Existing Table 8-1 is modified to include leakage risk classification for the industrial sectors of: All Other Metal Ore Mining, Asphalt Paving Mixture and Block Manufacturing, Ethyl Alcohol Manufacturing, Hardware manufacturing, Guided Missile and Space Vehicle Manufacturing, and Nonferrous Forging.

Existing Table 8-1 is also modified to insert the industrial sector of mineral wool manufacturing into the high leakage classification portion of the table and remove it from the medium leakage classification section of the table.

Existing Table 8-1 was modified to remove a blank row.

Rationale for Section 95870 Table 8-1: Industry Assistance.

This shift in assistance factor levels in the second and third compliance periods is needed to provide additional certainty and time for industry to successfully transition to lower-carbon production methods while also allowing additional time for staff to obtain the results of new research that will improve the data, measurement, and metrics of economic leakage risk and will provide additional insights into the potential leakage risk posed by long-term program implementation on industrial sectors.

The change to include new sectors is needed to allow these new entrants to receive appropriate allocations, pursuant to Board Resolutions 12-33 and 11-32.

This change for the mineral wool sector is needed to account for new data for the mineral wool manufacturing sector, and to change this sector's industry assistance allocations accordingly, pursuant to Board Resolutions 12-33 and 11-32.

The removal of the empty row is needed to remove a typographical error in the table.

Section 95890. General Provisions for Direct Allocations.

Summary of Section 95890(b).

Section 95890(b) is modified to indicate that the eligibility requirement for direct allocation to an EDU in this section applies to EDUs that are covered entities.

Rationale for Section 95890(b).

This modification was needed to clarify that only EDUs that are covered entities are required to comply with the MRR and obtain a positive or qualified positive emissions data verification statement for the prior year.

Summary of Section 95890(c).

Section 95890(c) is added to require EDUs that are not covered entities but are listed in Table 9-3 to register pursuant to section 95830 to receive allowances.

Rationale for Section 95890(c).

An entity must be registered in the allowance tracking system in order to receive an allowance allocation. This addition ensures that EDUs that are not required to register as covered entities will register in order to receive allowances.

Summary of Section 95890(d).

New section 95890(d) is added to establish criteria for universities and public service facilities to receive allocations.

Rationale for Section 95890(d).

This addition is needed so that universities and public service facilities can receive direct allocations.

Summary of Section 95890(e)

New section 95890(e) is added to provide an allowance allocation to the operators of legacy contract generators.

Rationale for Section 95890(e)

This new section is necessary to allow for the Executive Officer to transfer the allowances to the operator of the legacy contract generator if the operator meets the requirements in the new section 95894, and if they have report pursuant to MRR and obtain a positive or a qualified positive verification statement pursuant to MRR.

Summary of Section 95890(f)

New section 95890(e) is added to provide an allowance allocation to natural gas suppliers.

Rationale for Section 95890(f)

This addition is needed so that natural gas suppliers can receive direct allocations.

Summary of Section 95890(g).

Section 95890(g) is added to state the eligibility requirement for direct allocation to a public wholesale water agency. The agency must comply with MRR and must have obtained a positive or qualified positive verification statement for the prior year.

Rationale for Section 95890(g).

This section is needed to provide the eligibility requirement for allocations pursuant to section 95895, and to ensure that an agency receiving the allocation complies with MRR. ARB needs to set some baseline eligibility requirements to ensure that allocation is based on verified emission data.

Summary for Section 95890(h)

Section 95890(h) is added to not allow for allocation to one entity under both 95870(f) and 95870(g)

Rationale for Section 95890(h)

This section is necessary to ensure that no entity can receive allocations for the same emissions under two different allowance allocation sections

Section 95891. Allocation for Industry Assistance.

Summary of Section 95891(a)(2).

Section 95891(a)(2) is modified to correct the spelling of "budget" and to add a reference to the carbon weighted tonne and complexity weighted barrel metrics that in the MRR.

Rationale for Section 95891(a)(2).

The first change is needed to correct a spelling error. The MRR reference is added to clarify the metrics for the second compliance period.

Summary of Section 95891(a)(3).

New Section 95891(a)(3) is added to provide free allocation for new entrant covered facilities with a NAICS code that matches the first three digits of a NAICS code in Table 8-1. The leakage risk category for the new entrant covered facility is low.

Rationale for Section 95891(a)(3).

This section provides allocation for new entrant covered facilities that have a similar activity to Table 8-1 but do not have an exact match of NAICS code. Because the leakage analysis was performed only on covered facilities that time, this section provides a framework to allocate to new entrants prior to concluding a new leakage analysis.

Summary of Section 95891(b).

Section 95891(b) is modified to define calculations for the amount of true-up allowances under the product-based allocation calculation methodology. Existing true-up portion of the equation and related variables are deleted.

Rationale of Section 95891(b).

This change is needed to expand and clarify the allowance amount allocated as part of a true-up. The change allows the true-up to account for changes in allocation methodology, production output, benchmarks, leakage risk classification, and cap adjustment factor.

Summary of Section 95891, Table 9-1.

Table 9-1 is modified to add new NAICS sector definitions, associated manufacturing activities, benchmark units and benchmark values. It is also modified to change the benchmark units and/or values for existing manufacturing activities.

Rationale for Section 95891, Table 9-1.

The addition is necessary to ensure that 1) industry assistance is provided to the new entrants to the California Cap-and-trade program, 2) industrial sectors receive industry assistance based on product-based benchmark rather than energy-based benchmark provided that ARB has sufficient technical information/data to develop product-based benchmarks, and 3) newly available information/data is accurately reflected in the existing benchmarks.

Summary of newly added NAICS sector definitions (Table 9-1)

Table 9-1 is modified to add food manufacturing, breweries, wineries, secondary smelting and alloying of aluminum, secondary smelting, refining, and alloying of nonferrous metal (except copper and aluminum), iron and steel foundries and metal forging.

Rationale for newly added NAICS sector definitions (Table 9-1)

The addition is necessary to ensure that industry assistance is provided to the new entrants to the California Cap-and-trade program and also to ensure that industrial sectors receive industry assistance based on product-based benchmark rather than energy-based benchmark provided that ARB has sufficient technical information/data to develop product-based benchmarks.

Summary of tissue benchmark modification (Table 9-1)

The tissue product unit is modified from air dried short ton of tissue to air dried short ton of tissue produced adjusted by water absorption capacity. Subsequently, the benchmark value is modified from 1.14 to 0.101 and the unit of measurement was changed. .

Rationale for tissue benchmark modification (Table 9-1)

The modification for the benchmark unit is necessary to adjust the product unit to allow fair and equal comparison of the emissions from benchmarked facilities that produce tissue product to account for the absorbency of the tissue. The modification for the benchmark value was necessary to reflect the change in the calculation methodology using the new product unit. The change also reflects newly available data years.

Summary of recycled boxboard benchmark modification (Table 9-1)

The recycled boxboard benchmark is modified from 0.499 to 0.516.

Rationale for recycled boxboard benchmark modification (Table 9-1)

The modification is necessary to make the benchmark representative of normal operation years by reflecting newly available data.

Summary of flat glass benchmark modification (Table 9-1)

The flat glass benchmark value is modified from 0.471 to 0.495.

Rationale for flat glass benchmark modification (Table 9-1)

The modification is necessary to reflect newly available data and also to base the benchmark on the years that are representative of normal operation years.

Summary of container glass benchmark modification (Table 9-1)

The container glass benchmark value is modified from 0.264 to 0.270.

Rationale for container glass benchmark modification (Table 9-1)

The modification is necessary to reflect newly available data and also to base the benchmark on the years that are representative of normal operation years.

Summary of cement benchmark modification (Table 9-1)

The cement benchmark is modified from 0.718 to 0.742.

Rationale for cement benchmark modification (Table 9-1)

The modification is necessary to take into account the emissions associated with biomass combustion to reduce GHG emissions.

Summary of cold steel rolling benchmark modification (Table 9-1)

The pickled steel sheet benchmark is modified from 0.0126 to 0.0123, the cold rolled and annealed steel sheet benchmark is modified from 0.0313 to 0.052, and the tin steel plate benchmark is modified from 0.0610 to 0.1108.

Rationale for cold steel rolling benchmark modification (Table 9-1)

The pickled steel sheet benchmark, the cold rolled and annealed steel sheet benchmark and the tin steel plate benchmark are modified to reflect newly available data.

Summary of oil and natural gas extraction and processing benchmark modification (Table 9-1)

The thermal EOR crude oil extraction benchmark is modified from 0.0816 to 0.0811, the non-thermal crude oil extraction benchmark is modified from 0.0082 to 0.0076, and the natural gas liquid extraction benchmark is modified from 0.0146 to 0.0118. A new benchmark for onshore natural gas processing plants (>25 MMscf/day) is proposed as 0.0220 Allowances / Barrel of Gas Processed Equivalent.

Rationale for oil and natural gas extraction and processing benchmark modification (Table 9-1)

The thermal EOR crude oil extraction benchmark, the non-thermal crude oil extraction benchmark and the natural gas liquid extraction benchmark are modified to reflect newly available data. The emissions data for large onshore natural gas processing plants was previously included in the existing non-thermal crude oil extraction benchmark. Pursuant to stakeholder feedback, the emissions from the large gas plants are now

included in the new benchmark for onshore natural gas processing plants, as they are considered separate facilities under MRR.

Summary of Section 95891(c).

Section 95891(c) is modified to make minor corrections to the energy-based allocation methodology equation and term definitions. The subscript "a" denoting different activities is removed.

Rationale for Section 95891(c).

The energy-based allocation methodology does not support more than one activity per facility. Only one annual assistance factor and cap adjustment factor can be used in the formula.

Summary of Section 95891(c)(3).

Section 95891(c)(3) is modified to explicitly calculate the energy-based allocation methodology for new entrants. The definition of new entrants is expanded to covered facilities whose emissions exceeded the threshold in 2012 or opted into the program in 2012 or subsequent years.

Rationale for Section 95891(c)(3).

This change is made to provide an equitable allocation methodology for new entrants under the energy-based methodology. The definition of new entrant is necessary to include facilities that operated in California but were under the cap-and-trade threshold.

Summary of Section 95891(c)(3)(A).

New Section 95891(c)(3)(A) is added to provide for the calculation of allowance allocation using the energy-based allocation methodology for new entrants with no historical emissions to report. This methodology is based on engineering estimates of a facility's energy use.

Rationale for Section 95891(c)(3)(A).

This section is needed to calculate allocation to facilities without historical reported emissions. Since other methodologies rely on historical energy usage reported through MRR, a new methodology is needed. The only available data for the calculation of allocation is engineering estimates. To correct any error in these estimates, 95891(c)(3)(B) includes a calculation for true-up allowances.

Summary of Section 95891(c)(3)(B).

New section 95891(c)(3)(B) is added to provide for the calculation of allowance allocation using the energy-based allocation methodology for new entrants with changing facility emissions. This methodology is based on historical energy use reported through MRR and updates annually until the facility emissions are stable pursuant to 95891(c)(3)(D).

Rationale for Section 95891(c)(3)(B).

This section is needed to calculate allocation to facilities with changing energy usage. Since new entrants may be experiencing substantial growth in energy usage, it is necessary to provide an allocation methodology that scales with energy usage. This provides equitable treatment to new entrant facilities that are ramping up production to full capacity and existing facilities whose allocation was based on running at full capacity.

Summary of Section 95891(c)(3)(C).

New section 95891(c)(3)(C) is added to provide for the calculation of allowance allocation using the energy-based allocation methodology for new entrants that have reached stable emissions pursuant to 95891(c)(3)(D).

Rationale for Section 95891(c)(3)(C).

This section is needed to calculate allowance allocation for facilities with stable emissions using a similar method for covered facilities defined in 95891(c).

Summary of Section 95891(c)(3)(C)(1).

New section 95891(c)(3)(C)(1) is added to clarify the data years for the stable allowance allocation to be based on the previous three years of reported energy-usage through MRR.

Rationale for Section 95891(c)(3)(C)(1).

This section is needed to define the data years used in 95891(c)(3)(C). This section provides data years to the energy-based allocation methodology in 95891(c). The only difference is the data period: 95891(c) uses 2008-2010 and 95891(c)(3)(C) uses a historical three year average based on the year the facility reached stability.

Summary of Section 95891(c)(3)(D).

New section 95891(c)(3)(D) is added to provide the equation to calculate allowance allocation if the historical emissions of a facility are stable. This equation calculates percent change in emissions of year "t-2" to the average of years "t-3" and "t-4". If the percent change was less than 10 percent, the emissions of years "t-2" to "t-4" are considered stable.

Rationale for Section 95891(c)(3)(D).

This equation is needed to define stability for sections 95891(c)(3)(B-C). 10 percent is chosen to allow normal variation in annual operation to not affect allocation.

Summary of Section 95891(d)(1)(A)

Section 95891(d)(1)(A) was modified to clarify that the allocations would be for the initial allocation for 2013 and 2014 vintage allowances

Rationale for Section 95891(d)(1)(A)

This change was necessary to clarify that these are the initial allocation because we have added a true-up allocation process that will be for 2015 vintage allowances.

Summary of Section 95891(d)(1)(B)

Section 95891(d)(1)(B) is modified to add a true-up allowance amount term for refineries without an EII.

Rationale for Section 95891(d)(1)(B)

Initial allowance allocation relies on historical data and the true up term allows actual output data to be used for the calculation instead of estimated data. The true up is limited to those under the output based methodology unless actual emissions are eighty percent or smaller of baseline emissions. This is consistent with the approach for EII refineries.

Summary of Section 95891(d)(2)(B)

Section 95891(d)(2)(B) is modified to change A to TrueUp so that refineries can use these allowances as TrueUp allowances. Additionally purchases was corrected to sales

Rationale for Sections 95891(d)(2)(B)

This change is necessary to allow refineries to use the TrueUp amount for earlier budget years pursuant to sections 95856(h)(1)(C) and 95856(h)(2)(C). The correction of purchases to sales is to correct for an inadvertent typo in the original Regulation.

Summary of Section 95891(e).

New section 95891(e) is added to provide the methodology for calculating the amount of allowances directly allocated to a university or public service facility.

Rationale for Section 95890(e).

Because university covered entities and public service facilities will be allocated allowances for transition assistance pursuant to section 95870(f), this section was needed to explain the calculation of the amount of allowances allocated to these entities.

Summary of Section 95891(e)(1).

New section 95891(e)(1) is added to provide the formula used for allocating allowances from budget year 2015 to university covered entities and public service facilities and to define the terms in the equation. The 2015 allocation is calculated as the baseline fuel consumed multiplied by the fuel efficiency benchmark less the emissions attributed to electricity sold plus true-up term for 2013 and 2014 calendar years. This section also provides the equation for calculating the amount of true-up allowances to account for changes in allocation not properly accounted for in prior allocations.

Rationale for Section 95891(e)(1).

University covered entities and public service facilities will receive allowances for transition assistance pursuant to section 95870(f) and it is necessary to provide the calculation methodology. Because these entities did not receive allowances in 2013 and 2014, and there will be no remaining allowances of these vintages that could be allocated, it is necessary to allocate their allowances for 2013 and 2014 as well as for 2015 from the budget year 2015. The true-up portion of the allocation allows these entities to use the true-up allowance amount from budget year 2015 for earlier budget years obligations pursuant to sections 95856(h)(1)(C) and 95856(h)(2)(C).

Summary of Section 95891(e)(2).

New section 95891(e)(1) is added to provide the formula used for allocating allowances to university covered entities and public service facilities for budget years 2016 to 2020 and to define the terms in the equation.

Rationale for Section 95890(e)(2).

Because university covered entities and public service facilities will be allocated allowances for transition assistance pursuant to section 95870(f), this section was needed to explain the calculation of the amount of allowances allocated to these entities for the budget years 2016 to 2020.

Summary of Section 95891(e)(3).

New section 95891(e)(3) is added to state the data sources the Executive Officer may use to determine appropriate baseline values for calculating allowances directly allocated to a university or public service facility.

Rationale for Section 95890(e)(3).

This section is needed to indicate what data will be used to establish baseline values for allowance allocation calculations pursuant to section 95890(e).

Summary of Section 95891(e)(4).

New section 95891(e) is added to require universities or public service facilities that are allocated allowances to report, no later than June 30, 2016 and each calendar year thereafter, the disposition of allowance valued received in the prior calendar year, and how the allowance value was used to reduce greenhouse gas emissions and achieve additional environmental and economic benefits for California.

Rationale for Section 95890(e)(4).

University covered entities and public service facilities are allocated allowances for transition assistance and to recognize their leadership in reducing greenhouse gas emissions and achieving additional environmental and economic benefits for California. Many of these entities have committed to ARB that they will use the allowance value to continue to pursue these benefits and emission reductions. Because California Health and Safety Code sections 38570 et seq. require that ARB maximize additional environmental and economic benefits for California in conjunction with implementing a market based compliance program such as this Cap-and-Trade Regulation, it is

necessary that entities that receive allowance value in recognition of their emission reduction activities report on their use of allowance value received. This requirement is consistent with the reporting required of EDUs that receive allowance allocations for the benefit of ratepayers.

Summary of Section 95891(e)(4)(A).

New section 95891(e)(4)(A) is added to require entities subject to this section to report the monetary value of allowances received, and explains that this value shall be calculated based on the average market clearing price of the quarterly auctions held during the calendar year the allowances are allocated.

Rationale for Section 95891(e)(4)(A).

Because university covered entities and public service must report on their use of allowance value pursuant to this section, it is necessary to describe how the allowance value will be calculated and to require that they report the calculated allowance value received in each calendar year.

Summary of Section 95891(e)(4)(B).

New section 95891(e)(4)(B) is added to require each university or public service facility to annually report to the Executive Officer describing the disposition of any allowance value receive in the prior year, and how the allowance value was used to reduce greenhouse gas emissions and achieve additional environmental and economic benefits.

Rationale for Section 95891(e)(4)(B).

Like EDUs, university covered entities and public service entities are allocated allowances for transition assistance. For EDUs the value of allowances must be used to benefit ratepayers, and similarly, the value of allowances will benefit taxpayers that pay the costs of operating university and municipal facilities. Because California Health and Safety Code sections 38570 et seq. require that ARB maximize additional environmental and economic benefits for California in conjunction with implementing a market based compliance program, it is necessary that entities receiving allowance value report on their use of allowance value received.

Summary of Section 95891(f)

New section 95891(f) is added to describe the calculation to adjust the California GHG Allowances directly allocated to a Legacy Contract Counterparty that is receiving industrial allocation pursuant to 95891 (b) through (d).

Rationale for Section 95891(f)

This new section is necessary to reduce the allowance allocation to the legacy contract counterparty. This purpose of allocation under 95891 (b-d) is to minimize leakage associated with GHG costs. In the case of a legacy contract, there is no cost to the counterparty and thus no need for allowance allocation so this section adjusts for the allowances associated with the legacy contract.

Summary of Section 95891(f)(1)

This section provides an adjustment to occur in vintage 2015 allowances.

Rationale of Section 95891(f)(1)

This section is needed to account for the adjustment related to legacy contract emissions for 2013 through 2015.

Summary of Section 95891(f)(2)

This section provides a formula for adjustment to industrial allocations for years after 2015.

Rationale for Section 95891(f)(2)

This section is necessary to account for the adjustment related to legacy contract emissions for years after 2015.

Summary of Section 95891(f)(3)

New Section 95891(f)(3) is added to address situations where the adjustment of the allowance allocation to the Legacy Contract Counterparty is greater than the counterparty's allocation for that year. This section also adds the ability to adjust the allowance allocation of an entity with a direct corporate association with the Legacy Contract Counterparty.

Rationale for Section 95891(f)(3)

The addition of this new section is necessary ensure the Legacy Contract Counterparty, that is an industrial entity, will not have its allowance allocation adjusted any lower than zero and the balance of the calculation pursuant to section 95891(f) will be deducted from the counterparty's direct corporate association. This situation is possible since the 2015 adjustment will include the adjustment from 2013-2015.

Summary of Section 95891(f)(4)

Section 95891(f)(4) is added to cease the adjustment if the legacy contract counterparty renegotiates considering greenhouse gas costs.

Rationale of Section 95891(f)(4)

This change is necessary to allow for the counterparty to renegotiate the contract and not have the adjustment applied to their allocation, which would result in an over-allocation to the counterparty.

Section 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.

Summary of Section 95892(a). Table 9-3

Section 95892(a), Table 9-3, is modified to change the names of and type designations (Publically Owned Utility (POU), Investor Owned Utility (IOU), or electrical cooperative (Coop) for three EDUs. Modifications to the allowance allocation for budget years 2015 to 2020 are made for two EDUs.

Rationale for Section 95892(a). Table 9-3

It is necessary to change the names in Table 9-3 for two EDUs due to change in ownership, and to account for a name change for one EDU. For two of these EDUs It is necessary to change the EDU type designation to account a change in ownership and correct an error. Allowance allocation amounts were made for two EDUs based on new information about the cost burden faced by each EDU's ratepayers. In both cases, new information about the emissions associated with imported electricity requires adjustments in allocation amounts. Adjustments made to allocations for 2015 to 2020 will also account for under- or over-allocation in 2013 and 2014.

In addition, 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. The allocation to Anza Electric Cooperative was increased because

imported electricity serving Anza's ratepayers has higher emissions than previously assumed. The allocation to Surprise Valley Electrical Corporation was reduced because emissions from their electricity imports are significantly lower than what was assumed based on previous information. No change was made to the overall allocation to the electricity sector.

Section 95893. Allocation to Natural Gas Suppliers for Protection of Natural Gas Ratepayers.

Summary of Section 95893(a)

New section 95893(a) is added to provide the formula by which natural gas suppliers will receive allowances on behalf of their ratepayers.

Rationale for Section 95893(a).

The allocation formula for distribution of allowances to natural gas suppliers is for the benefit of rate payers and must further the cap-and-trade emissions reduction objectives, including providing incentives to reduce emissions cost-effectively. This section allocates for every year based on the supplier's 2011 compliance obligation, taking into account the cap decline factor for the year of allocation. This ensures an increasing incentive as the cap declines.

Summary of Section 95893(b).

New section 95893(b) is added to explain that investor-owned utilities (public utility gas corporations) will receive free allocation into a special type of account called a Limited Use Holding Account. Publicly owned natural gas utilities will have the option to have allocations distributed to their limited use Holding Accounts or to their Compliance Accounts.

Rationale for Section 95893(b).

Natural gas suppliers that plan to monetize allowances on behalf of their ratepayers will receive a free allocation into limited use Holding Accounts. An increasing percentage of allowances given to public utility gas corporations are required to be monetized. The publicly owned natural gas utilities have more flexibility.

Summary of Section 95893(c), Monetization Requirement.

New section 95893(c) is added to require that natural gas utilities have an increasing percentage of their freely allocated allowances placed into a Limited Use Holding

Account and consigned to auction in the calendar year corresponding to the budget year from which those allowances was issued.

Rationale for Section 95893(c).

Monetization of allowances through auction is intended to ensure that the amount of value given to distribution utilities is transparent to the public, and that this value is used on behalf of ratepayers.

Summary of Section 95893(d).

New section 95893(d) is added to establish limitations on how a natural gas utility can use proceeds raised from the sale of allowances at auction.

Rationale for Section 95893(d).

These limitations ensure that allowance value given to a natural gas utility will be used on behalf of ratepayers and in ways that are consistent with AB 32 statutory objectives.

Summary of Section 95893(d)(1) and 95892(d)(2).

New sections 95893(d)(1) and 95892(d)(2) are added to clarify that the natural gas utility proceeds from the sale of allowances at auction will be subject to limitations imposed by either the California Public Utilities Commission or by the governing bodies of publicly owned utilities.

Rationale for Section 95893(d)(1) and 95892(d)(2).

Proceeds from sale at allowances at auction will generate a new revenue stream for a natural gas utility. This revenue stream will need to be accounted for along with all other revenues and costs in the ratemaking actions of the CPUC and the governing bodies of the POUs.

Summary of Section 95893(d)(3).

New section 95893(d)(3) is added to clarify that the statutory goals of AB 32 apply to all utility proceeds raised through auctioned allowances and that all proceeds must be used to the benefit of ratepayers rather than for the benefit of shareholders (or any other entities). Further limitations are placed on how rebates directly to customers must function.

Rationale for Section 95893(d)(3).

Limiting the use of proceeds on behalf of ratepayers and for the purposes of AB 32 ensures that natural gas utility adopt programs that support GHG reductions and minimize cost of these programs to their customers.

Limiting customer rebates such that they appear on the fixed portion of customer bills and cannot be based solely on the amount of natural gas consumed in any period after 2014 is intended to create an incentive to use less natural gas and ensure a GHG price signal in retail rates.

Summary of Section 95893 (d)(4)

Section 95893 (d)(4) is added to state that public utility gas corporations must provide equal treatment to procurement and delivery customers and delivery only customers.

Rationale for Section 95892 (d)(4)

This section is necessary to ensure that all customers are treated equitably.

Summary of Section 95893 (d)(5)

New section 95893 (d)(5) is added to clarify what are prohibited uses of allocated allowance value.

Rationale for Section 95893 (d)(5)

This section is necessary to ensure that allowance value is used solely for the benefit of ratepayers in line with the goals of AB 32.

Summary of Section 95893(e), Reporting on the Use of Auction Proceeds.

New section 95893(e) is added to require that natural gas utilities report to ARB on how they use proceeds generated from the sale of allowances at auction.

Rationale for Section 95893(e).

This provision will ensure transparency on how natural gas utilities use allowance value and demonstrate that this value is used for the purposes of AB 32 implementation.

Summary of Section 95893(e) Table 9-4

Section 95893(e) was added to provide the consignment requirements for natural gas suppliers.

Rationale for Section 95893(e) Table 9-4

This change is necessary to direct natural gas suppliers to consign a given percentage of allowances for the corresponding year in the table.

Section 95894. Allocation to Legacy Contract Generators for Transition Assistance.

Summary of Section 95894

New Section 95894 is added to provide allowances to legacy contract generators.

Rationale for section 95894

New Section 95894 is necessary to provide allowances to legacy contract generators for two purposes: (1) to provide transitional assistance or (2) in the case of those with an industrial facility counterparty, to adjust the counter party allocation and provide those allowances to the legacy contract generator.

Summary of Section 95894(a)

New section 95894(a) is added to describe the entity in a legacy contract situation eligible to receive the allocation and how they will transmit the required information.

Rationale for Section 95894(a)

This new section is necessary to direct the primary or alternate account representative representing the operator of the legacy contract generator to demonstrate they have met the criteria, and the date by which they need to submit the information.

Summary of Section 95894(a)(1)

New section 95894(a)(1) is added to describe how to request allowance allocation.

Rationale for 95894(a)(1)

This new section is necessary to start the process of evaluating and determining whether the entity is eligible to receive the allowance allocation.

Summary of Section 95894(a)(2)

New section 95894(a)(2) is added to describe the information the entity must submit regarding the contract with the legacy contract counterparty.

Rationale for Section 95894(a)(2)

This new section is necessary to prove to ARB there is a legacy contract with the counterparty and the effective dates for which there are legacy contract emissions.

Summary of Section95894 (a)(3)

New section 95894(a)(3) is added to require an attestation be submitted to ARB to prove to ARB there is a legacy contract.

Rationale for Section95894 (a)(3)

This new section is necessary to prove the information declared is true and to facilitate ARB legal action against the entity requesting allowance allocation if the information submitted is false information

Summary of Section 95894(a)(3)(A)

New section 95894(a)(3)(A) is added to require the entity to state under penalty of perjury a legacy contract exists with the counterparty.

Rationale for Section 95894(a)(3)(A)

This new section is necessary to have the entity state under penalty of perjury that a contract exists with the counterparty and it doesn't cover the cost of compliance with the Cap-and-Trade Regulation for the purchase of the electricity and or the qualified thermal output. ARB needs to ensure that a contract actually exists, but may not be able to see the contract itself due to confidentiality provisions.

Summary of Section 95894(a)(3)(B)

New section 95894(a)(3)(B) is added to require the entity state under penalty of perjury that the legacy contract was entered into before September 1, 2006, the month Assembly Bill 32 was enacted.

Rationale for Section 95894(a)(3)(B)

This new section is necessary limit the contracts that are eligible to be considered legacy contracts. If the contract was signed after this date, it should have considered the potential costs of GHG emissions in the terms of the agreement.

Summary of Section 95894(a)(3)(C)

New section 95894(a)(3)(D) is added to require the operator to discuss renegotiation of the costs of compliance with this Regulation with the counterparty.

Rationale for Section 95894(a)(3)(C)

This new section is necessary to insure the operator discussed the possibility of allocating these costs with the counterparty and has exhausted all other options to cover the cost of compliance.

Summary of Section 95894(a)(4)

New section 95894(a)(4) is added to require the entity to include in the letter to ARB the data requested in section 95894(d), if it is requested by ARB.

Rationale for Section 95894(a)(4)

This new section is necessary so that, if additional data and information is available to determine the appropriate allowance allocation, the entity must provide the data. This will ensure ARB's allocation is as accurate as possible.

Summary of Section 95894(a)(5)

New section 95894(a)(6) is added to allow the covered entity to update the data and information submitted.

Rationale for Section 95894(a)(5)

New section 95894(a)(6) is necessary to allow for the consideration of the most current, accurate and up-to-date information related to the legacy contract.

Summary of Section 95894(b)

New section 95894(b) is added to allow ARB to review the data and information required to be submitted in section 95894(a).

Rationale for Section 95894(b)

This section is necessary so ARB can determine whether the content submitted meets the requirements for the entity to receive an allowance allocation.

Summary of Section 95894(c)

New section 95894(c) is added to describe the calculation legacy contract generators with a counterparty that receives allowance allocation pursuant to 95891(b-d).

Rationale for Section 95894(c)

New section 95894(c) is necessary to determine the number of allowances to be provided to the legacy contract generator. This amount will also be subtracted from the counterparty or a direct corporate association of the counterparty.

Summary of Section 95894(c)(1)

This new section is added to describe the calculation of allowances to the stand-alone electricity generators.

Rationale for Section 95894(c)(1)

This new section is needed to be able to determine the appropriate number of allowances to allocate to the stand-alone electricity generators.

Summary of Section 95894(c)(2)

This new section is added to describe the calculation of allowances to all other legacy contract generators

Rationale for Section 95894(c)(2)

This new section is needed to be able to determine the appropriate number of allowances to allocate to allocate to all other legacy contract generators, that are not stand-alone electricity generators,

Summary of Section 95894(d)

New section 95894(d) is added to describe the calculation for determining the number of allowances for legacy contract generators for all remaining generators for transitional assistance.

Rationale for Section 95894(d)

New section 95894(d) is necessary to determine the number of allowances to be allocated to the generators for two years of transitional assistance as directed in Board Resolution 12-33, for generators that do not have a contract with an industrial counterparty.

Summary of Section 95894(d)(1)

This new section is needed to describe the calculation of allowances to be provided to the legacy contract generator.

Rationale for Section 95894(d) (1)

This new section is necessary to determine the number of allowances to be allocated to the legacy contract generator that is a stand-alone generator.

Summary of Section 95894(d)(2)

This new section is needed to describe the calculation of allowances to be provided to all remaining generators in this category.

Rationale for Section 95894(d) (2)

This new section is necessary to determine the number of allowances to be allocated to all remaining generators in this category

Summary of Section 95894(e)

New section 95894(e) is added so that ARB can consider the data submitted by the entity pursuant to MRR for the emissions year 2012.

Rationale for Section 95894(e)

New section 95894(e) is necessary for ARB to use the data submitted under MRR in the calculation to determine the number of allowances to allocate to the operator of a legacy contract generator.

Summary of Section 95894(f)

New section 95894(f) is added to cease the allowance allocation.

Rationale for Section 95894(f)

New section 95894(f) is necessary to end the allowance allocation, or pro-rate the allowance allocation if the contract expires or the operator of the legacy contract generator permanently ceases operations of the legacy contract generator.

Section 95895. Allocation to Public Wholesale Water Agencies for Protection of Water Ratepayers.

Summary of Section 95895

Section 95890(b) is added to provide, in Table 9-5, the quantity of allowances to be allocated to a public wholesale water agency from budget years 2015-2020.

Rationale for Section 95895

This section is needed to state the number of allowances to be allocated to a public wholesale water agency from budget years 2015-2020. The number of allowances is the expected compliance obligation for electricity used to convey water for each agency, assuming that it would meet the renewable energy percentages required under California's RPS.

Section 95910. Auction of California GHG Allowances.

Summary of Section 95910(a)(2).

Section 95910(a)(2) is modified to specify that the existing auction scheduling convention only extends through 2014.

Rationale for Section 95910(a)(2).

This change is necessary to provide clarity to market participants about when auctions will be held and when the new proposed schedule would be in effect.

Summary of Section 95910(a)(3).

New section 95910(a)(3) is added to refer readers to the auction schedule in Appendix C.

Rationale for Section 95910(a)(3).

This addition is necessary to provide clarity to market participants about when auctions will be held post-2014.

Summary of Section 95910(b)(1).

Section 95910(b)(1) is modified to specify to which subsections of 95870 the section makes reference.

Rationale for Section 95910(b)(1).

This modification is needed to eliminate imprecision about which subsection of 95870 is being referenced.

Summary of Section 95910(c)(1)(B).

Section 95910(c)(1)(B) is modified to specify that future vintage allowances for sale at an Advance Auction which remain unsold will be sold at a Current Auction when their vintage equals the current year.

Rationale for Section 95910(c)(1)(B).

This change is needed to clarify how unsold future vintage allowances would be treated if they were not sold by the year of their vintage.

Summary of Section 95910(d)(4)(B).

Section 95910(d)(4)(B) is modified to specify that the deadline for consignment is 5 p.m. Pacific time, 75 days before the auction.

Rationale for Section 95910(d)(4)(B).

This amendment is required to ensure that consigning entities complete consignment during working hours when staff is available to assist them, if needed.

Summary of Section 95910(d)(4)(C).

New section 95910(d)(4)(C) is added to specify that consignment must be completed by 5 p.m., 75 days before the auctions, as listed in Appendix C.

Rationale for Section 95910(d)(4)(C).

This amendment is required to ensure that consigning entities complete consignment during working hours when staff is available to assist them, if needed.

Section 95911. Format for Auction of California GHG Allowances.

Summary of Section 95911(c)(4)

Section 95911(c)(4) was modified to clarify that the Executive Officer may delay the opening of the auction bidding window for up to one hour in cases of technical difficulties.

Rationale for Section 95911(c)(4)

This modification is needed to allow for delays for technical reasons, which can be resolved in a timely manner so as not to cause the entire auction to be rescheduled.

Summary of Section 95911(d)(2)

Existing section 95911(d)(2) is modified to refer to the section in which the auction purchase limit is defined.

Rationale for Section 95911(d)(2)

This modification is needed to ensure clarity in the subsection's reference to the auction purchase limit.

Summary of Section 95911(d)(4)(A)

Section 95911(d)(4)(A) is modified to raise the purchase limit for covered entities to 20 per cent during the first compliance period.

Rationale for Section 95911(d)(4)(A)

The change is made to accommodate an entity that has experienced a growth in emissions due to opening a new facility. ARB has set the holding and purchase limits so that covered entities could meet their compliance obligations for the first compliance period through a combination of direct allocation and participation in eight quarterly auctions. ARB is aware that an entity opening a new facility could have been constrained by the purchase limit. The increase in the purchase limit, for the auction to

which it will apply when the Regulation becomes effective, is increased by more than the amount necessary for the entity to purchase allowances at auction to meet its increased compliance needs.

Summary of Section 95911(d)(5)

New Section 95911(d)(5) was added to specify auction purchase limits for the second and third compliance periods. Similar to the existing requirements for the first compliance period, the new requirements still provide larger purchase limits for covered and opt-in entities that voluntarily associated entities.

Rationale for Section 95911(d)(5)

This section is needed to ensure equitable access to allowances at auction for all market participants in the second and third compliance periods.

Summary of Section 95911(d)(6)

This new section is needed to clarify that, from 2015-2020, the auction purchase limit for voluntarily associated entities will be 4 percent of the allowances at auction.

Rationale for Section 95911(d)(6)

This addition is necessary to codify the auction purchase limit for voluntarily associated entities.

Summary of Section 95911(e)(3)(B)

Existing section 95911(e)(3)(B) is modified to eliminate the reference to section 95914.

Rationale for Section 95911(e)(3)(B)

This modification is necessary because section 95914 does not define the holding limit.

Section 95912. Auction Administration and Participant Application.

Summary of Section 95912(b)
Section 95912(b) was modified to fix a grammatical error.

Rational for Section 95912(b)
This modification was needed to clarify the existing text.

Summary of Section 95912(d)(4).

Section 95912(d)(4) is modified to specify that the deadline for auction application is 5 p.m. Pacific time, 30 days before the auction.

Rationale for Section 95912(d)(4).

This amendment is required to ensure that registration is completed during working hours when staff is available to assist them, if needed.

Summary of Sections 95912(d)(4)(C) and (D).

New sections 95912(d)(4)(C) and (D) are added to require a change in the distribution of the purchase limit and holding limit among corporate associates with separate CITSS accounts to be provided with other auction application information. Sections 95912(d)(4)(C) and (D) are renumbered to sections 95912(d)(4)(E) and (F).

Rationale for Section 95912(d)(4)(C) and (D).

The new sections make clear that any change in the distribution of the purchase limit and/or the holding limit among corporate associates must be reported along with other auction application information. The requirement for reporting the allocation of the purchase limit is not new as it was formerly in Section 95914(d)(4).

Summary of Section 95912(d)(4)(E).

Section 95912(d)(4)(E) is modified to require entities to identify an ongoing investigation, including a change in the status of an investigation, of an alleged violation of rules and regulations governing the financial markets, including possible securities, commodities or financial market violations

Rationale for Section 95912(d)(4)(E).

The change to Section 95912(d)(4)(E) is needed to improve ARB's ability to monitor investigations of alleged violations in other financial markets and makes clear that a change in the status of an investigation, if applicable, is information that should be reported along with other auction application information.

Summary of Section 95912(d)(5).

New section 95912(d)(5) is added to explain that changes to the auction application close to the auction will result in denial of the auction application.

Rationale for Section 95912(d)(5).

This change is necessary to ensure correct processing of the auction applications.

Summary of Section 95912(d)(6)

Section 95912(d)(6) was modified to fix a reference to just the Reserve Sale to all auctions.

Rational for Section 95912(d)(6)

This modification was needed to ensure the requirements of the section apply to all ARB auctions and not just the subset of Reserve sale auctions.

Summary of Section 95912(e)(2).

Section 95912(e)(2) is modified to set the deadline for changes to auction application information at 5 p.m., 30 days before the auction.

Rationale for Section 95912(e)(2).

This amendment is required to ensure application changes are completed during working hours when staff is available to assist, if needed.

Summary of Section 95912(f).

New section 95912(f) is added to set a deadline of 30 days before an auction for entities to inform the Auction Administrator of their intent to bid.

Rationale for Section 95912(f).

This addition is necessary to streamline the auction preparation process.

Summary of Section 95912(j).

Section 95912(j) is modified to establish that the deadline for reception of the bid guarantee is 5 p.m. Pacific time, 12 days before the auction.

Rationale for Section 95912(j).

This change is needed to ensure that participants complete the bid guarantee process during working hours when staff is available to assist, if needed.

Summary of Section 95912(j)(1)(A).

Section 95912(j)(1)(A) is modified to continue to allow a cash bid guarantee via a wire transfer but cash in the form of a bank check or cashier's check will not be accepted as a form of a bid guarantee for a quarterly auction.

Rationale for Section 95912(j)(1)(A).

The deletion of bank checks or a cashier's check in Section 95912(j)(1)(A) is needed to ensure timely settlement following an auction.

Summary of Section 95912(j)(1)(D).

New section 95912(j)(1)(D) is added to allow certain surety bonds to be used as a bid guarantee.

Rationale for Section 95912(j)(1)(D).

This addition is needed to expand the bid guarantee options for auction participants.

Summary for Section 95912(j)(3).

New section 95912(j)(3) is added to stipulate that non-cash bid guarantees must be payable within one business day of payment request.

Rationale for Section 95912(j)(3).

This addition is necessary to facilitate timely completion of auction clearance. Various minor and non-substantive clarifications were also made to section 95912 to ensure clarity and consistency in terminology throughout the Regulation.

Summary of Section 95912(j)(5)(C)

This section is added to clarify that if an auction participant submits a single bid guarantee to cover bids in both Current and Advance Auctions then it must cover the combined maximum value of bids to be submitted in both auctions.

Rationale for Section 95912(j)(5)(C)

This section is added for clarification in the submission of bid guarantees.

Summary of Section 95912(j)(5)(D)

This section is added to clarify that submitting a bid guarantee that is less than the maximum value of bids to be submitted is a violation of the regulation.

Rationale for Section 95912(j)(5)(D)
This section is added to clarify the existing regulation and enforcement procedures surrounding the submission of bid guarantees.

Summary of Section 95912(j)(9)

New section 95912(j)(9) is modified to refer to section 95911(j)(1).

Rationale for Section 95912(j)(9)

This change is necessary to ensure that the section reference is correct.

Summary of Section 95912(k)(2)(C-D).

New section 95912(k)(C-D) is added to specify where the proceeds from auctions will be placed.

Rationale for Section 95912(k)(2)(C-D).

This addition is necessary to provide an update on where auction monies are deposited.

Summary of Section 95912(k)(3).

Section 95912(k)(3) is modified to delete the reference to serial numbers of allowances.

Rationale for Section 95912(k)(3).

This modification is necessary to clarify that allowances will be transferred into winning bidder's Holding accounts, rather than transferring serial numbers.

Section 95913. Sale of Allowances from the Allowance Price Containment Reserve.

Summary of Section 95913(b).

New section 95913(b) is an existing section now moved to replace the previous section and states that entities registered in a linked jurisdiction may not purchase allowances from California's Reserve sales.

Rationale for Section 95913(b).

This modification was made to improve readability in this section.

Summary of Section 95913(d).

Section 95913(d) is modified to specify the timing of Reserve sales.

Rationale for Section 95913(d).

These modifications are necessary to provide clarity to potential Reserve sale participants.

Summary of Section 95913(d)(2)

Section 95913(d)(2) was modified to limit the Reserve sales in the first compliance period to the existing schedule in the Regulation.

Rationale for Section 95913(d)(2)

This modification was needed to end the current schedule once the newly proposed schedule was in place.

Summary of Sections 95913(d)(3) and (6)

New sections 95913(d)(3) and (6) were added to include the new schedule in Appendix C for the Reserve sales starting in 2015.

Rationale for Sections 95913(d)(3) and (6)

These sections are needed to provide the exact dates for Reserve sales, the existing schedule did not specify exact dates and made implementation a challenge when the schedule required an auction the day after a holiday.

Summary of Section 95913(e)(1).

New section 95913(e)(1) is added to specify that the deadline to notify the Reserve sale administrator of intent to bid is 20 days.

Rationale for Section 95913(e)(1).

This addition is necessary to establish limits to when an entity can express desire for Reserve sale participation.

Summary of Section 95913(e)(2).

New section 95913(e)(2) is added to require that entities whose auction application information changes 30 days prior to, or 15 days after, a Reserve sale may not participate in that sale.

Rationale for Section 95913(e)(2).

This addition is necessary to streamline the Reserve sale process and ensure there are no issues for settlement because one entity may not meet the auction application requirements due to changes in their registration information.

Summary of Section 95913(f)(1)

Section 95913(f)(1) is modified to clarify the source of allowances that fill the three tiers of the Allowance Price Containment Reserve.

Rationale for Section 95913(f)(1)

This change is necessary given the eligibility of additional allowances for the Reserve sale immediately preceding the compliance obligation on November 1 pursuant to section 95913(f)(5).

Summary of Section 95913(f)(5)

New section 95913(f)(5) is added to outline the sale of additional allowances through the Reserve sale immediately preceding the compliance obligation on November 1 in addition to those in the Allowance Price Containment Reserve.

Rationale for Section 95913(f)(5)

This subsection is necessary to outline changes made to the Reserve sale immediately preceding the compliance obligation on November 1 in order to satisfy Board Resolution 12-51.

Summary of Section 95913(f)(5)(A)

New section 95913(f)(5)(A) is added to specify that additional allowances will be eligible for sale beginning at the Reserve sale immediately preceding the compliance obligation on November 1, 2015.

Rationale for Section 95913(f)(5)(A)

The new subsection is necessary to outline the mechanics of an additional cost containment feature pursuant to Board Resolution 12-51.

Summary of Section 95913(f)(5)(B)

New section 95913(f)(5)(B) is added to outline the filling of accepted bids at the highest price tier of the Reserve sale immediately preceding compliance obligation on November 1 if the number of accepted bids is less than or equal to the quantity of eligible allowances.

Rationale for Section 95913(f)(5)(B)

This subsection is required to outline the purchase process of additional allowances made available through the Reserve sale immediately preceding the compliance obligation on November 1.

Summary of Section 959133(f)(5)(C)

New section 95913(f)(5)(C) is added to outline that the filling of accepted bids at the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 will occur through the procedure outlined in section 95913(h)(5) if the number of accepted bids exceeds the quantity of eligible allowances.

Rationale for Section 95913(f)(5)(C)

This subsection is made to outline the purchase process of additional allowances made available through the Reserve sale immediately preceding the compliance obligation on November 1.

Summary of Section 95913(f)(5)(D)

New section 95913(f)(5) is added to specify that accepted bids for allowances in the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 will first be filled with Allowance Price Containment Reserve allowances as specified in section 95870(a).

Rationale for Section 95913(f)(5)(D)

This subsection is necessary to specify the order in which allowances will fill accepted bids at the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 pursuant to Board Resolution 12-51.

Summary of Section 95913(f)(5)(E)

New section 95913(f)(5)(E) is added to specify that once all allowances outlined in section 95870(a) have been sold at the Reserve sale immediately preceding the compliance obligation on November 1, accepted bids for the highest price tier will be filled beginning with the latest vintage in the Auction Holding Account, moving to more recent vintages until all allowances outlined in section 95870(J)(1) have been sold or all accepted bids are filled.

Rationale for Section 95913(f)(5)(E)

This subsection is necessary to specify the order in which allowances will fill accepted bids at the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 pursuant to Board Resolution 12-51.

Summary of Section 95913(f)(5)(F)

New section 95913(f)(5)(F) is added to specify that all allowances sold in the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 will be retired as Allowance Price Containment Reserve allowances for compliance.

Rationale for Section 95913(f)(5)(F)

This change is necessary to clarify the order in which allowances purchased in the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 will be removed from the compliance accounts of entities.

Summary of Section 95913(g)(2)(A).

Section 95913(g)(2)(A) is modified to continue to allow a cash bid guarantee via a wire transfer but cash in the form of a bank check or cashier's check will not be accepted as a form of a bid guarantee for a Reserve sale.

Rationale for Section 95913(g)(2)(A).

The deletion of bank checks or a cashier's check in Section 95913(g)(2)(A) was needed to ensure timely settlement following a Reserve sale.

Summary of Section 95913(g)(2)(D).

New section 95913(g)(2)(D) is added to allow certain surety bonds to be used as a bid guarantee for Reserve sales.

Rationale for Section 95913(g)(2)(D).

This addition is needed to expand the bid guarantee options for Reserve sale participants.

Summary of Section 95913(g)(3).

New section 95913(g)(3) is added to specify that non-cash bid guarantees for Reserve sales must be payable within one business day.

Rationale for Section 95913(g)(3).

This addition is necessary to facilitate timely completion of Reserve sale clearance.

Summary of Section 95913(g)(7).

New section 95913(g)(7) is added to state that the intent to bid notification requirements and bid guarantee submittal requirements shall be at least four days before bid guarantee submittal dates.

Rationale for Section 95913(g)(7).

This addition is necessary to ensure that staff has enough time to process the requirements.

Summary of Section 95913(h)(1)

Section 95913(h)(1) is modified to differentiate the purchase determinations for all Reserve sales and the Reserve sale immediately preceding the compliance obligation on November 1.

Rationale for Section 95913(h)(1)

This change is necessary to make additional allowances eligible for the highest price tier of the Reserve sale immediately preceding the compliance obligation on November 1 in fulfillment of Board Resolution 12-51.

Summary of Section (h)(1)(A)

New section 95913(h)(1)(A) is added to specify that Reserve sales will continue until all accepted bids are filled or until the Allowances Price Containment Reserve allowances made available through in section 95870(a) have been sold.

Rationale for Section (h)(1)(A)

This change is made to clarify the purchase determination of Reserve sales that are not immediately preceding the compliance obligation on November 1.

Summary of Section 95913(h)(1)(B)

New section 95913(h)(1)(B) is added to outline that the Reserve sale immediately preceding the compliance obligation on November 1 will continue until all accepted bids are filled or all allowances made eligible through section 95870(a) and section 95870(j)(1) have been sold.

Rationale for Section 95913(h)(1)(B)

This change is required to clarify the purchase determination of allowances sold at the Reserve sale immediately preceding the compliance obligation on November 1 pursuant to Board Resolution 12-51.

Summary of Section 95913(h)(3)(B)

Existing section 95913(h)(3)(B) is modified to clarify that the section referred to is 95913(g).

Rationale for Section 95913(h)(3)(B)

This change is necessary so that the Regulation refers to the correct section.

Summary of Section 95913(h)(4)(B)

Existing section 95913(h)(4)(B) is modified to clarify that the section referred to is 95913(h)(4)(A) and that only accepted bids will be fulfilled, not just any bid.

Rationale for Section 95913(h)(4)(B)

This change is necessary to clarify the referenced section and which bids will be fulfilled.

Summary of Section 95913(h)(5)(B)

Existing section 95913(h)(5)(B) is modified to clarify that the section referred to is 95913(h)(5)(A).

Rationale for Section 95913(h)(5)(B)

This change is necessary so that the Regulation refers to the correct section.

Summary of Section 95913(i)(3)

Section 95913(h)(3) was modified change the reference to the Air Pollution Control Fund to the Greenhouse Gas Reduction Fund.

Rationale for Section 95913(i)(3)

This modification is necessary to update to the new fund into which auction monies are placed due to recent statutes enacted by the legislature.

Section 95914. Auction Participation and Limitations.

Summary of Section 95914(a)(2)

Section 95914(a)(2) was modified to clarify which information must be accurate and complete.

Rationale for Section 95914(a)(2)

This modification is necessary to ensure clarity on which items could impact auction participation.

Summary of Section 95914(c)

The titles for section 95914(c) are modified, dropping a reference to auction participants.

Rationale for Section 95914(c)

The change is needed to clarify that the information release restrictions apply to entities beyond those that are directly participating in the auction.

Summary of Section 95914(c)(1)

Section 95914(c)(1) is modified to remove the existing text that creates exceptions from the auction information disclosure prohibitions.

Rationale for Section 95914(c)(1)

The change is needed because the existing exceptions will be placed in a longer list of exceptions contained in new sections 95914(c)(1)(A) through (D).

Summary of Section 95914(c)(1)(A)

Section 95914(c) is modified to clarify the information that must not be disclosed by auction participants. Section 95914(c)(1)(A) expands the information on qualification status to include the intent to participate at auction, auction approval status, and maintenance of continued auction approval.

Rationale for Section 95914(c)(1)(A)

The change expands the current provision, which prohibits disclosure of auction qualification status to include disclosures of whether an entity would participate in an auction, not just qualify. The change is needed to prohibit disclosures of intent to bid in an auction by entities qualified for auction participation. Prohibiting this disclosure would help prevent entities from coordinating their activities at an auction or trying to evade the purchase limits.

Summary of Sections 95914(c)(1)(C) and (D)

Sections 95914(c)(1)(C) and (D) are modified to reflect a change in the number of subsections within 95914(c)(1).

Rationale for Sections 95914(c)(1)(C) and (D)

The change is needed to reflect the renumbering of the section.

Summary of Section 95914(c)(1)(E)

Section 95914(c)(1)(E) is removed because ARB will not rely on the auction administrator to inform auction participants on which information is confidential. That is ARB's role.

Rationale for Section 95914(c)(1)(E)

The change is needed to remove a function that ARB has not assigned to the auction administrator and will instead be included in regulation.

Summary of Section 95914(c)(2)

Section 95914(c)(2) is renumbered to 95914(c)(3). New section 95914(c)(2) is added to specify specific circumstances in which the information in section 95914(c)(1) may be released.

Rationale for Section 95914(c)(2)

Disclosures to members of a direct corporate association or to auction bid advisors already disclosed to ARB are already listed as exceptions in the existing Regulation. The change is needed to add two new exceptions and place the existing exceptions into a combined list.

Summary of Section 95914(c)(2)(A)

New section 95914(c)(2)(A) is added to include a reference to the existing Regulation section 95914(c)(1).

Rationale for Section 95914(c)(2)(A)

The change is needed to clarify disclosure exemptions by placing the existing text in a new list of exceptions.

Summary of Section 95914(c)(2)(B)

New section 95914(c)(2)(B) is added to include a reference to the existing Rrgulation section 95914(c)(1).

Rationale for Section 95914(c)(2)(B)

The change is needed to clarify disclosure exemptions by placing the existing text in a new list of exceptions.

Summary of Section 95914(c)(2)(C)

New section 95914(c)(2)(C) is added to allow publicly-owned utilities to release some information on auction participation related to their participation in generation projects operated by a Joint Powers Authority or with other publicly-owned utilities, when the release is required by public accountability rules or rules governing projects operated by a Joint Powers Authority or with other publicly-owned utilities.

Rationale for Section 95914(c)(2)(C)

The changes are needed to remove a potential conflict between the Regulation and the other legal and regulatory requirements that publicly-owned utilities may face. Section 95833(c) was originally included to deal with this issue and related issues. However, extensive discussions with stakeholders indicated that a more specific exception is needed.

Summary of Section 95914(c)(2)(D)

New section 95914(c)(2)(D) is added to allow electric distribution utilities to release some information when the release is required by the California Public Utilities Commission.

Rationale for Section 95914(c)(2)(D)

The changes are needed to remove a potential conflict between the Regulation and the other legal and regulatory requirements that electric distribution utilities may face. Section 95833(c) was originally included to deal with this issue and related issues. However, extensive discussions with stakeholders indicated that a more specific exception is needed. There is still a requirement to limit any release of auction related information to the minimum amount needed to comply with CPUC requirements.

Summary of Section 95914(c)(3)(C)

Section 95914(c)(3)(C) is modified and expanded to include the specific disclosures and an attestation that bid advisors and their clients must make to ARB.

Rationale for Section 95914(c)(3)(C)

The change is needed to allow ARB to collect specific information about the identity and contact information of the bid advisors and the entities they serve. The existing text does not specify the information needed for the disclosure or include the attestation by the officer of the registered entity that the entity understands the regulatory requirements to protect confidential information.

The information on bid advisors will enable staff to understand which auction participants are using the same bid advisors. ARB would use this information to evaluate whether registered entities are coordinating their compliance instrument acquisition and trading strategies.

Summary of Section 95914(c)(3)(D)

New section 95914(c)(3)(D) is added to specify information that auction advisors must disclose with regards to services performed for auction participants.

Rationale for Section 95914(c)(3)(D)

This provision is necessary to provide ARB with greater oversight of advisors and specifies the information to be disclosed by auction advisors.

Summary for Section 95914(d)(2)

Section 95914(d)(2) was modified to reiterate there must be a sharing of purchase limits as part of registration.

Rationale for Section 95914(d)(2)

This modification is necessary to ensure all auction participants have provided essential information to be eligible for auction participation during registration for the tracking system.

Summary of Section 95914(d)(4), (5) and (6).

Sections 95914(d)(4), (5) and (6) were deleted.

Rationale for Section 95914(d)(4), (5) and (6).

Section 95914(d)(4) requiring entities to report a purchase limit allocation among corporate associates is now covered in Section 95912(d)(4)(c). Since members of a corporate association must report a purchase limit allocation, when applicable, the procedure for determining acceptable bids in the absence of a purchase limit allocation described in Section 95914(d)(5) and (6) is not needed.

Section 95920. Trading.

Summary of Section 95920(b)(5)(C).

New section 95920(b)(5)(C) is added to specify, when an entity has a violation of the holding limit and fails to cure the problem within 5 business days, that the Executive Officer's transfer of allowances to the Auction Holding Account for sale on behalf of the entity will be from the entity's Holding Account and if needed, from the entity's Compliance Account.

Rationale for Section 95920(b)(5)(C).

This change is needed to specify the order in which an entity's accounts will be accessed if the entity fails to cure a holding limit violation in a timely manner.

Summary of Section 95920(d)(2)

Section 95920(d)(2) is modified to remove all operative language from the section, which is changed to a title. The limited exemption definition is now contained in section 95920(d)(2)(A).

Rationale for Section 95920(d)(2)

The change is needed to clarify the definition and calculation of the limited exemption.

Summary of Section 95920(d)(2)(A)

Section 95920(d)(2)(A) is modified to give a clearer definition of the limited exemption and that allowances must be placed in the compliance account to qualify for inclusion within the limited exemption.

Rationale for Section 95920(d)(2)(A)

The change is needed for clarity.

Summary of Section 95920(d)(2)(B)

Section 95920(d)(2)(B) is deleted and replaced with a definition of the calculation of the limited exemption that takes effect on January 1, 2015. On that date, the limited exemption will equal the sum of the annual emissions reports received in 2012, 2013, and 2014 that have received positive or qualified positive emissions data verification statements for emissions counted towards the compliance obligation defined for the first compliance period in section 95851(a). In addition, the limited exemption will include 2014 emissions that are included in section 95851(b).

Rationale for Section 95920(d)(2)(B)

The text is updated to remove the expired date on which the limited exemption is created. The text also replaces text from section 95920(d)(2)(C), (F) and (G) which contained the original schedule for increasing the limited exemption.

Summary of Section 95920(d)(2)(C)

Section 95920(d)(2)(C) is modified to remove existing text increasing the limited exemption on October 1 of each year. Text is added that increases the limited exemption beginning in 2015 on November 1 of each year. The increase is the amount of emissions included in the most recent emissions data report that has received a positive or qualified positive emissions data verification statement for emissions that generate a compliance obligation pursuant to sections 95851(a) and (b).

Rationale for Section 95920(d)(2)(C)

The change is needed to clarify that the increases in the limited exemption beginning in 2015 will include the "full scope" emissions.

Summary of Section 95920(d)(2)(D)

Section 95920(d)(2)(D) is modified to include minor changes to clarify the existing process for calculating the limited exemption and no substantive changes are made.

Rationale for Section 95920(d)(2)(D)

The change is needed to clarify the calculation of the limited exemption.

Summary of Section 95920(d)(2)(E)

Section 95920(d)(2)(E) is eliminated and replaced with renumbered existing section 95920(d)(2)(I).

Rationale for Section 95920(d)(2)(E)

The section is no longer needed because modified section 95920(d)(2)(B) now includes the provisions governing calculation of the limited exemption using emissions reports from the first compliance period.

Summary of Section 95920(d)(2)(F)

Section 95920(d)(2)(F) is eliminated and replaced with the requirement that the limited exemption will be zero throughout the first compliance period for opt-in covered entities that have only emissions specified in section 95851(b) in the first compliance period.

Rationale for Section 95920(d)(2)(F)

The existing text is no longer needed because modified section 95920(d)(2)(C) now includes the provisions governing the annual updating of the limited exemption.

Summary of Section 95920(d)(2)(G)

Section 95920(d)(2)(G) is eliminated and replaced with the requirement that allowances allocated to entities pursuant to section 95870(d) and (e) do not count against the holding limit until January 1 of their vintage year.

Rationale for Section 95920(d)(2)(G)

The existing text is no longer needed because modified section 95920(d)(2)(B) now includes the provisions governing calculation of the limited exemption through January 1, 2015.

Section 95921. Conduct of Trade.

Summary of Section 95921(a)(3)(B)

The existing text is modified to require that the transfer request process be completed within three days after the execution date or termination date set in the transaction agreement.

Rationale for Section 95921(a)(3)(B)

The change was needed to clarify the deadline for completing the transfer request. The existing text sets the deadline three days after the "settlement date" of the transaction agreement. However, some transaction agreements involve multiple transfers, terms requiring actions other than the transfer of allowances, or have completion of the

transfer request process as the last step for settling the agreement. For these agreements the term settlement date was unclear.

The new terms should clarify the deadline. The term "execution date" refers to the date the transaction agreement requires the parties to take some action, such as the transfer of allowances. If there are multiple transfers scheduled in the agreement then there will be an execution date associated with each. This provision is needed to ensure the transfer request is completed soon after an agreement requires a transfer. The term "termination date" refers to the date the agreement ends. This would apply to agreements that have the completion of the transfer process as the final step.

Summary of Section 95921(a)(3)(C)

New section 95921(a)(3)(C) adds a requirement that the transfer request process must be completed within three days of the transfer of "consideration" from the purchaser to the seller. That is, the transfer process must be completed once payment by the purchaser gives it a financial interest in the allowances held by the seller.

Rationale for Section 95921(a)(3)(C)

The change is needed to ensure that payments by the purchaser are immediately followed by the transfer of the compliance instruments. Otherwise, the payments would create the type of "holding on behalf" that is prohibited under section 95921(f)(1).

Summary of Section 95921(a)(3)(D)

New section 95921(a)(3)(D) adds a requirement that the transfer request process must be completed within three days of the execution of the underlying trade on an exchange or other trading platform. That is, the transfer process must be completed once payment through the exchange settlement process gives the purchaser a financial interest in the allowances held by the seller.

Rationale for Section 95921(a)(3)(D)

The change is needed to ensure that payments by the purchaser are immediately followed by the transfer of the compliance instruments. Otherwise, the payments would create the type of "holding on behalf" that is prohibited under section 95921(f)(1).

Summary of Section 95921(a)(4)

New section 95921(a)(4) prohibits entities from submitting a transfer request in the absence of a transaction agreement with the entity listed as the destination account in the transfer request.

Rationale for Section 95921(a)(4)

Stakeholders have raised concerns that the process for remedying deficient transfer requests could be used to determine another entity's account balances. The main concern is that a large transfer request could place the destination account over the holding limit, which would be revealed to the submitting entity when the transfer is deemed deficient. This could conceivably allow the submitting entity to calculate the destination account's current balance. The provision would make the ploy a violation.

Summary of Section 95921(b)

An existing requirement in section 95921(b) is modified to clarify that the Executive Officer may request documentation on the transaction agreement for which a transfer request is submitted.

Rationale for Section 95921(b)

The change is needed to clarify an existing requirement.

Summary of Section 95921(b)(1)

New section 95921(b)(1) introduces a list of three fields that must be completed for all transfer requests.

These include the holding account number and identification of two account representatives for the entity submitting the transfer request, and the account number and account representative for the destination account. These fields are required under the existing Regulation. The account representative for the destination account is only needed if the transfer requires confirmation.

The transfer request will also require the vintage and type (allowance versus offset) of the compliance instrument. These two fields are required because the account representatives cannot designate serial numbers of the instruments they wish to transfer.

The existing text is deleted.

Rationale for Section 95921(b)(1)

The change is needed because the original list of information required to complete a transfer request, contained in section 95921(b)(1) through (7) is being replaced in its entirety.

Summary of Section 95921(b)(1)(A)

This section contains the text originally contained in section 95921(b)(1), which is deleted.

Rationale for Section 95921(b)(1)(A)

The change is needed to reflect the reorganization of the section and is not a substantive change.

Summary of Section 95921(b)(1)(B)

This section contains a modification of text contained in existing section 95921(b)(2), which is deleted. The section is modified to require identification of account representatives for the destination account only if the type of transfer requires confirmation. It is also changed to reflect the fact that transfers may be to accounts other than holding accounts.

Rationale for Section 95921(b)(1)(B)

The movement of this text is required in part to reflect the reorganization of section 95921(b). The modifications to the text are made to clarify when the requirement applies, based on section 95921(a).

Summary of Section 95921(b)(1)(C)

This section contains a new requirement that the transfer request specify the type, vintage and number of compliance instruments. This requirement replaces the requirements of section 95921(b)(3), which is deleted.

Rationale for Section 95921(b)(1)(C)

The change is needed to reflect the decision to structure the tracking system so that account holders do not see serial numbers. The existing text used the serial numbers to allow account holders to designate which compliance instruments should be part of a transfer request. Without serial numbers, account holders will designate instruments to be transferred by designating the type and vintage along with the number to be transferred.

Summary of Section 95921(b)(2)

New section 95921(b)(2) requires the identification of the type of transaction agreement for which the transfer request is submitted. Entities submitting a transfer request will have to select one of three agreement types to match the underlying agreement for which they are submitting the transfer request.

Existing section 95912(b)(2) is deleted, with the requirement it contained modified and renumbered as section 95912(b)(1)(A).

Rationale for Section 95921(b)(2)

The existing Regulation included a single list of information requirements that applied to all transfer requests regardless of the type of transaction agreement for which the transfer requests are submitted. Stakeholders and account holders commented to ARB that the requirements didn't capture the variety of provisions contained in the transaction agreements that they use or were developing. Based on these comments, ARB decided to replace the "one-size-fits-all" approach with one that captures the types of agreements in use or may soo0n be developed.

The new text of this section constitutes the first step of the new process, in which the account representative identifies the type of transaction agreement involved. In the next step, the account representative would be presented with a list of information requirements that matches that agreement type.

ARB chose this process based on its evaluation of the transfer requests processed in CITSS to date. As part of this evaluation, ARB has reviewed a number of transactions agreements requested from CITSS account holders to ensure that the new process captures the types of agreements currently in use. ARB has also had discussions with account representatives who are developing new contract products. Finally, ARB has had discussions with the staff of the Intercontinental Exchange (ICE) to determine what information is available to the representatives from the exchange.

Summary of Section 95921(b)(2)(A)

This new section contains text that defines the first of three transaction agreement types. The first type covers over the counter agreements for which delivery will take place no more than three days from the date the parties enter into the transaction agreement.

Rationale for Section 95921(b)(2)(A)

The change is needed to define the first type of transaction agreement that account representatives may select when submitting a transfer request. This type will include the simplest bilateral transfers.

Summary of Section 95921(b)(2)(B)

This new section contains text that defines the second of the three transaction agreement types. The second type covers 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.

Rationale for Section 95921(b)(2)(B)

The change is needed to define the second type of transaction agreement that account representatives may select when submitting a transfer request. This type will include the most complex bilateral transfers. Consequently, it will have the most involved information requirements.

Summary of Section 95921(b)(2)(C)

This new section contains text that defines the third of the three transaction agreement types. The third type includes exchange-based agreements for the sale of compliance instruments through an Exchange or Board of Trade.

Rationale for Section 95921(b)(2)(C)

The change is needed to define the third type of transaction agreement that account representatives may select when submitting a transfer request. This type will include any exchange-based trade.

Summary of Section 95921(b)(3)

New section 95921(b)(3) introduces the list of information that must be submitted for transfer requests resulting from over-the-counter transaction agreements for sale of compliance instruments that have a delivery date no more than three days after the parties enter into the agreement.

The date of settlement of the agreement is required, as in the current Regulation. However, the new text provides two conditions that determine how the entity enters the date. If completion of the transfer request is the last step of the agreement, the entity should enter the submission date of the transfer request as the settlement date. If there are terms that must be fulfilled after submissions of the transfer request, then the date those terms are expected to be completed should be entered.
Existing section 95912(b)(3) is deleted.

Rationale for Section 95921(b)(3)

The change is needed to define the types of agreements covered and to introduce the list of information that must be submitted for this type of transaction agreement.

The existing text is deleted. Since CITSS no longer displays serial numbers of the compliance instruments in an account the requirement to specify serial numbers is not needed. Instead, the new text of section 95921(b)(1)(C) has the account number enter the number of compliance instruments to be transferred, along with type and vintage.

Summary of Section 95921(b)(3)(A)

This section requires the account representative to enter the date the entity entered into the transaction agreement. This requirement is a modification of the existing text in section 95921(b)(4), which is deleted.

Rationale for Section 95921(b)(3)(A)

The text is modified for clarity and to reflect the reorganization of the section.

Summary of Section 95921(b)(3)(B)

This section requires the account representative to enter the date of settlement of the transaction agreement. If completion of the transfer request process is the last step of the agreement, the date the transfer request is submitted is entered as the settlement date. If there are other terms to be settled after the transfer request is approved, the date those terms are to be settled is entered as the settlement date. This requirement is a modification of the existing text in section 95921(b)(5), which is deleted.

Rationale for Section 95921(b)(3)(B)

The text is modified for clarity and to reflect the reorganization of the section.

Summary of Section 95921(b)(3)(C)

This section requires the account representative to enter the price of the instrument in U.S. or Canadian dollars. This requirement is a modification of the existing text in section 95921(b)(4), which is deleted.

Rationale for Section 95921(b)(3)(C)

The text is modified for clarity and to reflect the reorganization of the section.

Summary of Section 95921(b)(4)

New section 95921(b)(4) introduces the list of the information that must be submitted for transfer requests resulting from over-the-counter transaction agreements for sales that have delivery a date of no less than four days after the parties enter into the agreement, or involve multiple transfers or products under the same agreement.

Existing text for the section is deleted.

Rationale for Section 95921(b)(4)

The change is needed to define the types of agreements covered and to introduce the list of information that must be submitted for this type of transaction agreement.

Summary of Section 95921(b)(4)(A)

This section requires the account representative to enter the date the entity entered into the transaction agreement. This requirement is a modification of the existing text in section 95921(b)(4), which is deleted.

Rationale for Section 95921(b)(4)(A)

The date of the agreement is needed to enable ARB to interpret the price entered for the transfer agreement and to understand how far in advance of a transfer the parties entered into the commitment. For example, if the agreement is a forward contract with a fixed price, than ARB would understand that the price would reflect the market conditions at the time of the agreement, which may be different than market conditions when the transfer actually occurs. Absent information on when the agreement was created, the price may seem anomalous to market monitoring staff.

The text is modified for clarity and to reflect the reorganization of the section.

Summary of Section 95921(b)(4)(B)

This section requires the account representative to enter the date the transaction agreement expires. This requirement is a modification of the existing text in section 95921(b)(5), which is deleted.

Rationale for Section 95921(b)(4)(B)

The expiration date is needed because the submission of a transfer request may not be the last term to be settled under the agreement. If there are to be multiple transfers or payments, or if there are to be transfers of other products, entering an expiration date that is after the transfer submission date will indicate to ARB that the price may reflect other contract terms or that ARB analyses should consider that some transfers will be repeated in the future.

Summary of Section 95921(b)(4)(C)

This section requires the account representative to enter whether the agreement provides for further transfers of compliance instruments and if it does, to specify the frequency of the future transfers.

Rationale for Section 95921(b)(4)(C)

The provision is needed to allow ARB to interpret the price entered for the transfer request as part of market monitoring.

Summary of Section 95921(b)(4)(D)

This section requires the account representative to identify other products that are to be traded along with compliance instruments in a bundled agreement.

Rationale for Section 95921(b)(4)(D)

This information is needed to determine whether the transfer request qualifies for one of the exemptions from entering the price that are contained in section 95921(b)(6).

Summary of Section 95921(b)(4)(E)

This section requires the account representative to enter the price in U.S. or Canadian dollars if the price is fixed in the transaction agreement.

Rationale for Section 95921(b)(4)(E)

This section contains the existing requirement to provide a price originally contained in section 95921(b)(6).

Summary of Section 95921(b)(4)(F)

If the transaction agreement sets the price as a cost base plus a margin, this section requires the account representative to enter the cost base and the margin.

Rationale for Section 95921(b)(4)(F)

This section contains a modification of the existing requirement to provide a price originally contained in section 95921(b)(6). The provision is needed to enable ARB market monitoring staff to understand the basis for pricing carbon instruments.

Summary of Section 95921(b)(4)(G)

If the transaction agreement does not specify a price using either of the two other formats, the account representative should provide a brief description of the pricing method for the carbon component.

Rationale for Section 95921(b)(4)(G)

This information is needed to determine whether the transfer request qualifies for one of the exemptions from entering the price that are contained in section 95921(b)(6).

Summary of Section 95921(b)(5)

New section 95921(b)(5) defines the third type of transaction agreement and introduces the list of information that must be submitted for transfer requests resulting from exchange-based contracts.

Rationale for Section 95921(b)(5)

The change is needed to define the types of agreements covered and to introduce the list of information that must be submitted for this type of transaction agreement.

Summary of Section 95921(b)(5)(A)

New section 95921(b)(5)(A) requires the account representative to identify the exchange where the transaction is conducted.

Rationale for Section 95921(b)(5)(A)

The provision is needed to ensure correct information, to ensure that the transfer request is submitted for an exchange-based transaction. Knowledge of the exchange will enable ARB staff to assess the transfer based on analysis of data from the exchange.

Summary of Section 95921(b)(5)(B)

New section 95921(b)(5)(A) requires the account representative to identify the exchange where the transaction is conducted.

Rationale for Section 95921(b)(5)(B)

The provision is needed to allow ARB to automate analysis of transfer request data, especially as newer exchange-based products are developed.

Summary of Section 95921(b)(5)(C)

New section 95921(b)(5)(A) requires the account representative to identify the transaction agreement as spot or futures.

Rationale for Section 95921(b)(5)(C)

The provision is needed to allow ARB to automate analysis of transfer request data, especially as newer exchange-based products are developed.

Summary of Section 95921(b)(5)(D)

New section 95921(b)(5)(A) requires the account representative to provide the date of close of trading for the contract.

Rationale for Section 95921(b)(5)(D)

The provision is needed to allow ARB to automate analysis of transfer request data, as exchanges differentiate their contracts by closing date, and provide their data on the basis of closing date.

Summary of Section 95921(b)(5)(E)

New section 95921(b)(5)(A) requires the account representative to provide the price at close of trading for the contract.

Rationale for Section 95921(b)(5)(E)

This section contains a modification of the existing requirement to provide a price originally contained in section 95921(b)(6).

Summary of Section 95921(b)(6)

New section 95921(b)(6) introduces a list of instances in which entities will not be required to enter a price, but may enter a price of zero. The entities will have to indicate why they qualify for the exemption by selecting one of the instances listed.

Rationale for Section 95921(b)(6)

The section is needed to create an expansion of the list of exemptions contained in existing section 95921(b)(6), which is deleted.

Summary of Section 95921(b)(6)(A)

New section 95921(b)(6)(A) contains an exemption from entering a price for transfers between entities with a direct corporate association. The provision is a modification of the existing requirement contained in section 95921(b)(6), which is deleted.

Rationale for Section 95921(b)(6)(A)

The provision is needed for clarity by placing an existing exemption in a list with the newly-added exemptions from entering a price in transfer requests.

Summary of Section 95921(b)(6)(B)

New section 95921(b)(6)(B) contains an exemption from entering a price for transfers between entities with a direct corporate association. The provision is a modification of the existing requirement contained in section 95921(b)(6), which is deleted.

Rationale for Section 95921(b)(6)(B)

The provision is needed for clarity by placing an existing exemption in a list with the newly-added exemptions from entering a price in transfer requests.

Summary of Section 95921(b)(6)(C)

New section 95921(b)(6)(C) contains an exemption from entering a price for transfers from a publicly-owned utility (POU) to an entity or Joint Powers Authority operating a generation facility as a joint venture with the utility.

Rationale for Section 95921(b)(6)(C)

The change is needed to avoid interfering with the ability of publicly-owned utilities to comply with the rules to which they are subject when they participate in joint ventures with other public entities. These arrangements set the responsibility of publicly-owned utilities to supply compliance instruments to cover the emissions resulting from their share of a project's generation, and generally do not include a price.

Summary of Section 95921(b)(6)(D)

New section 95921(b)(6) contains an exemption from entering a price for transfers from a publicly-owned utility to a federal power authority to cover emissions associated with imported power.

Rationale for Section 95921(b)(6)(D)

The change is needed to avoid interfering with the ability of publicly-owned utilities to comply with the rules to which they are subject when they purchase electricity from federal power authorities. These arrangements set the responsibility of publicly-owned utilities to supply compliance instruments to cover the emissions resulting from their share of a project's generation, and generally do not include a price.

Summary of Section 95921(b)(6)(E)

New section 95921(b)(6) contains an exemption from entering a price for transfers from an electric distribution utility to an entity operating a generation facility under a tolling agreement or other long-term power purchase agreement that does not specify a price or cost basis for the sale of the compliance instruments alone.

Rationale for Section 95921(b)(6)(E)

The change is needed to avoid interfering with the ability of electric distribution utilities to purchase power from generators under contracts which may allow the utilities to supply the compliance instruments needed to cover the generation they purchase. The utilities would have to supply a price if the agreements specify one.

Summary of Section 95921(b)(6)(F)

New section 95921(b)(6) contains an exemption from entering a price for transfers resulting from a transaction agreement that bundles compliance instruments with other products and does not specify a price or cost basis for the sale of the compliance instruments alone.

Rationale for Section 95921(b)(6)(F)

The change is needed to deal with transaction agreements that involve the transfer of other products along with compliance instruments

Summary of Section 95921(b)(7)

This existing section is deleted.

Rationale for Section 95921(b)(7)

The provision is no longer needed since a regulation linking the California and Québec Cap-and-Trade programs has come into effect.

Summary of Section 95921(c)(1)(A)

Existing text is modified so that the entities submitting a deficient transfer request are only notified that the transfer request is deficient.

Rationale for Section 95921(c)(1)(A)

The changes address stakeholder concerns that account representatives could find out an entity's account balances by sending spurious transfer requests. Under the existing Regulation, account representatives of both accounts would be informed of the deficiency. Staff is proposing a process that would prevent the account representative submitting a transfer request from gaining information about the receiving entity's account. In addition, the new text of section 95921(a)(4) will make filing a transfer request in the absence of an underlying transaction agreement a violation.

Summary of Section 95921(c)(1)(B)

New section 95921(c)(1)(B) requires the Executive Officer to inform only the party responsible for the deficient transfer request of the exact nature of the deficiency.

Rationale for Section 95921(c)(1)(B)

Staff is proposing a process that would prevent the account representative submitting a transfer request from gaining information about the receiving entity's account.

Summary of Section 95921(c)(1)(C)

The existing text is renumbered from 95921(c)(1)(B) to 95921(c)(1)(C).

Rationale for Section 95921(c)(1)(C)

The change is needed to reflect reorganization of the section.

Summary of Section 95921(c)(1)(D)

The existing text is renumbered from 95921(c)(1)(C) to 95921(c)(1)(D).

Rationale for Section 95921(c)(1)(D)

The change is needed to reflect reorganization of the section.

Summary of Section 95921(c)(2)(A)

Existing text is modified to require the accounts administrator to inform the parties and the Executive Officer that the transfer is deficient.

Rationale for Section 95921(c)(2)(A)

The changes address stakeholder concerns that account representatives could find out an entity's account balances by sending spurious transfer requests. Under the existing Regulation, account representatives of both accounts would be informed of the deficiency. Staff is proposing a process that would prevent the account representative submitting a transfer request from gaining information about the receiving entity's account. In addition, the new text of section 95921(a)(4) will make filing a transfer request in the absence of an underlying transaction agreement a violation.

The change is also needed to give clear instruction to the accounts administrator.

Summary of Section 95921(c)(2)(B)

This new section requires the Executive Officer to inform the party submitting the transfer request that the transfer is deficient, if the deficiency arises from the information in the transfer request.

Rationale for Section 95921(c)(2)(B)

The change is needed so that the party responsible for the deficiency is notified of the problem to be corrected.

Summary of Section 95921(c)(2)(C)

If completion of a transfer request would lead to a violation of the holding limit, this new section requires the Executive Officer to inform the primary account representative for the account listed as the destination on a transfer request of the deficiency.

Rationale for Section 95921(c)(2)(C)

The change is needed so that the party responsible for the holding limit violation is notified of the problem to be corrected, without informing the other party to the transfer.

Summary of Section 95921(c)(2)(D)

The text in existing section 95921(c)(2)(B) is renumbered to 95921(c)(2)(D).

Rationale for Section 95921(c)(2)(D)

The change is needed to reflect the reorganization of the section.

Summary of Section 95921(e)(4)

This section was modified to remove reference to serial numbers.

Rationale for Section 95921(e)(4)

This modification was needed because serial numbers of instruments will not be made public.

Summary of Section 95921(f)(1)(A)

New section 95921(f)(1)(A) prohibits an entity from having an ownership or financial interest in the compliance instruments held by a second entity.

Rationale for Section 95921(f)(1)(A)

The change is needed to clarify the prohibition on "holding on behalf". The new text explains two conditions that could create this situation. An ownership or financial interest by one entity in the compliance instruments held by a second entity could give the first entity some control over the disposition of the compliance instruments. ARB would be unable to detect market manipulations if ARB could not observe who actually had control over the disposition of compliance instruments.

Summary of Section 95921(f)(1)(B)

New section 95921(f)(1)(B) prohibits an entity from establishing an agreement with a second entity that gives the second entity control over the holding or disposition of compliance instruments in the first entity's account. This section adds a clarification that the prohibition does not apply to forward contracts that do not contain terms applying to the compliance instruments in the first entity's account.

Rationale for Section 95921(f)(1)(B)

The change is needed to prohibit transaction agreements from containing provisions that have the effect of creating a "beholding on behalf" of situation. Again, ARB would be unable to detect market manipulations if ARB could not observe who actually had control over the disposition of compliance instruments. The change is also needed to explain that forward contracts that do not have such terms would not violate the prohibition. Stakeholders have asked for clarification on this point.

Summary of Section 95921(f)(1)(C)

New section 95921(f)(1)(C) permits an entity to purchase and hold compliance instruments for later transfer to entities with which it has a direct corporate association.

Rationale for Section 95921(f)(1)(C)

The change is needed to clarify that the prohibition on "holding on behalf of" does not apply to holdings for later transfer within a direct corporate association. ARB assumes that members of a direct corporate association must coordinate their activities to some degree. That is the reason that holding and purchase limits apply jointly to direct corporate associates. ARB believes its rule on direct corporate associates allow it to monitor the association's activities and that applying the "holding on behalf of" provisions to holdings for transfer within a corporate association would be unnecessarily burdensome.

Section 95922. Banking, Expiration, and Voluntary Retirement.

Summary of Section 95922(d)(2)

This section was modified to remove reference to serial numbers.

Rationale for Section 95922(d)(2)

This modification was needed because serial numbers of instruments will not be made public in the tracking system.

Section 95923. Disclosure of Cap-and-Trade Consultant or Advisor.

Summary of Section 95923(a)

New section 95923(a) is added to define a Cap-and-Trade Consultant or Advisor as a person or entity that is not an employee of an entity registered in the cap-and-trade program, but that is paid by that entity for specific advice to that entity.

Rationale for Section 95923(a)

This provision is necessary 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.

Summary of Section 95923(b).

New section 95923(b) is added to specify that entities receiving consulting or advisory services must disclose specific information for each consultant or advisor.

Rationale for Section 95923(b).

This addition is necessary to provide ARB with greater oversight over entities that have access to information from multiple entities participating in the Cap-and-Trade Program.

Summary of Section 95923(b)(1)

New section 95923(b)(1) is added to specify the information disclosure requirements for all entities employing Cap-and-Trade Consultants or Advisors.

Rationale for Section 95923(b)(1)

This provision is necessary to provide ARB with greater oversight over entities that have access to information from multiple entities participating in the cap-and-trade program.

Summary for Section 95923(b)(2)

New section 95923(b)(2) is added to specify the additional information disclosure requirements for entities employing Cap-and-Trade Consultants or Advisors, where additional information disclosure does not violate rules that must be observed by Consultants or Advisors.

Rationale for Section 95923(b)(2)

This provision is necessary to provide ARB with additional information about consultants and advisors, while also recognizing information disclosure limitations.

Summary for Section 95923(c)

New section 95923(c) is added to specify that information disclosure must occur at registration, when a contractual agreement is created, and within 30 days of a change to the information.

Rationale for Section 95923(c)

This provision is necessary to establish when program participants must disclose information about consultants or advisors.

Section 95942. Interchange of Compliance Instruments with Linked External Greenhouse Gas Emissions Trading Systems.

Summary of Sections 95942(f) and (g)

Sections 95942(f) and (g) were modified to include the disclosure of serial numbers for compliance instruments that are used for compliance across linked jurisdictions.

Rationale for Sections 95942(f) and (g)

These modifications were necessary to ensure that sharing of critical information such as the serial numbers of compliance instruments would prevent any opportunity for double counting of compliance instruments and help track their movement from accounts in one jurisdiction's entity accounts to another jurisdiction's entity accounts.

Subarticle 13. ARB Offset Credits and Registry Offset Credits.

Section 95970. General Requirements for ARB Offset Credits.

Summary of Section 95970.

The title of section 95970 is changed to General Requirements for ARB Offset Credits and Registry Offset Credits.

Rationale for Section 95970.

This change is necessary to reflect the content of the section. The section addresses general requirements for both ARB offset credits and registry offset credits.

Section 95971. Procedures for Approval of Compliance Offset Protocols.

Summary of Section 95971(b).

Section 95971(b) is changed to correct punctuation.

Rationale for Section 95971(b).

This change is necessary to improve the readability of the section.

Section 95972. Requirements for Compliance Offset Protocols.

Summary of Section 95972(c).

Existing section 95972(c) is changed to clarify that Compliance Offset Protocols (COP) may be applicable in the United States and its Territories, as well as Canada and Mexico.

Rationale for Section 95972(c).

This change is necessary to clarify that U.S. Territories are included in the geographical scope for offset projects.

Section 95973. Requirements for Offset Projects Using ARB Compliance Offset Protocols.

Summary of Section 95973(a)(2)(C)(3.).

Existing section 95973(a)(2)(C)(3.) is modified to support the addition of a potential Compliance Offset Protocol to this list.

Rationale for Section 95973(a)(2)(C)(3.).

This change is non-substantive and needed to support the inclusion of an additional potential Compliance Offset Protocol in this section.

Summary of Section 95973(a)(2)(C)(4.).

Existing section 95973(a)(2)(C)(4.) is modified to support the addition of a potential Compliance Offset Protocol to this list

Rationale for Section 95973(a)(2)(C)(4.).

This change is non-substantive and needed to support the inclusion of an additional potential Compliance Offset Protocol in this section.

Summary of Section 95973(a)(2)(C)(5.).

New section 95973(a)(2)(C)(5.) is added to include the Mine Methane Capture Projects Compliance Offset Protocol that staff is proposing to be adopted by the Board.

Rationale for Section 95973(a)(2)(C)(5.).

This change is necessary to support the potential adoption of a new Compliance Offset Protocol by the Board.

Summary of Section 95973(a)(3).

Existing section 95973(a)(3) is changed to clarify that offset projects may be located in the United States and its Territories, as well as Canada and Mexico.

Rationale for Section 95973(a)(3).

This change is necessary to clarify that U.S. Territories are included in the geographical scope for offset projects.

Summary of Section 95973(b).

Existing section 95973(b) is modified to include the requirement for regulatory compliance with all national, state, and local environmental and health and safety laws and regulations, and to define the scope of the regulatory requirements.

Rationale for Section 95973(b).

This change is necessary to clarify that the requirements for regulatory conformance do not only apply to environmental impact assessments, but also to all other environmental and health and safety laws and regulations. This is not a new requirement as each

Compliance Offset Protocol already includes this requirement. This change is needed to clarify the boundaries for evaluating regulatory compliance, including: the boundary is the project activity, the project activity must be subject to enforcement action by a regulatory body, and the timeframe for assessing regulatory compliance is the Reporting Period. This change is also needed to clarify that nonconformance with this subsection would result in ineligibly for crediting during the entire Reporting Period.

Section 95974. Authorized Project Designee.

Summary of Section 95974(a).

Existing section 95974(a) is modified to clarify that the Offset Project Operator (OPO) may not specify which rights and responsibilities they are assigning to the Authorized Project Designee (APD).

Rationale for Section 95974(a).

This change is necessary because if an OPO designates an APD, the APD will be responsible for implementing all of the administrative responsibilities for the offset project. This will ease the implementation of the program for ARB and the Offset Project Registries.

Summary of Section 95974(a)(1).

Existing section 95974(a)(1) is modified to clarify the timing at which an OPO may assign offset credits ownership rights to other parties.

Rationale for Section 95974(a)(1).

This change is necessary to streamline the implementation process. At the time of offset credit issuance, the OPO or APD submits a request for issuance, which includes information that is needed to assign ownership rights of the offset credits. This must be done each time offset credits are issued.

Summary of Section 95974(a)(2).

Existing section 95974(a)(2) is modified to include section references that were inadvertently left out of this section. In addition, this section is modified to require that the APD perform all administrative functions for the OPO. This section is also modified to clarify which requirements of sections 95983, 95985, and 95990 must be performed by the APD.

Rationale for Section 95974(a)(2).

These changes are necessary to ensure all references are correct and consistent throughout the Regulation. These changes will ease the implementation of the compliance offset program by providing ARB and the Offset Project Registry with a single point of contact for all administrative functions associated with the offset project. For sections 95983, 95985, and 95990, the intent of the clarification is to make it clear that the APD is only responsible for meeting those specific requirements that include reference to the APD.

Summary of Section 95974(a)(2)(A).

New section 95974(a)(2)(A) is added to require that a representative of the APD perform all administrative functions for the OPO and to make explicit that the APD is the main point of contact regarding the offset project. In addition, this section makes explicit that even though there is an APD, the OPO is still responsible for ensuring compliance of the project with the Regulation and COP.

Rationale for Section 95974(a)(2)(A).

This change is necessary because if an OPO designates an APD, the APD will be responsible for implementing all of the administrative responsibilities for the offset project and be the main point of contact. This will ease the implementation of the program for ARB and the Offset Project Registries.

Summary of Section 95974(a)(2)(B).

New section 95974(a)(2)(B) is added to require that any APD be designated as a Primary Account Representative (PAR) or Alternate Account Representative (AAR) on the OPO's CITSS account.

Rationale for Section 95974(a)(2)(B).

This change is necessary for oversight and enforcement of the Cap-and-Trade Program. In addition, ARB is requiring that any party associated with compliance instrument issuance or transfers be associated with the relevant CITSS account for the offset project.

Section 95975. Listing of Offset Projects Using ARB Compliance Offset Protocols.

Summary of Section 95975(a).

Existing section 95975(a) is modified to remove the ability of another third party to meet the requirements of this section.

Rationale for Section 95975(a).

This change is necessary to align the timing requirements with other provisions in the Regulation. At the time of offset credit issuance, the OPO or APD submits a request for issuance, which includes information that is needed to assign ownership rights of the offset credits to any other third party. This must be done each time offset credits are issued, and not before listing the offset project.

Summary of Section 95975(c)(1).

Existing section 95975(c)(1) is modified to correct punctuation.

Rationale for Section 95975(c)(1).

This change is non-substantive and needed to ensure correct punctuation in the Regulation.

Summary of Section 95975(c)(3).

Existing section 95975(c)(3) is modified to clarify that the project must be in compliance with all laws as well as regulations.

Rationale for Section 95975(c)(3).

This change is necessary to ensure consistent language throughout the Regulation and Compliance Offset Protocols.

Summary of Section 95975(d).

Existing section 95975(d) is modified to clarify that the attestations associated with listing an offset project must be submitted to ARB and/or the OPR at the time of listing.

Rationale for Section 95975(d).

This change is necessary to streamline OPR and ARB procedures when processing information related to an offset project.

Summary of Section 95975(e)(3).

Existing section 95975(e)(3) is modified to support the addition of a Compliance Offset Protocol to section 95975(e).

Rationale for Section .95975(e)(3)

This change is non-substantive and needed to support the inclusion of an additional Compliance Offset Protocol in this section.

Summary of Section 95975(e)(4).

Existing section 95975(e)(4) is modified to support the addition of a Compliance Offset Protocol to section 95975(e).

Rationale for Section 95975(e)(4).

This change is non-substantive and needed to support the inclusion of an additional Compliance Offset Protocol in this section.

Summary of Section 95975(e)(5).

New section 95975(e)(5) is added to include the potential Mine Methane Capture Projects Compliance Offset Protocol which staff is proposing for Board adoption.

Rationale for Section 95975(e)(5).

This change is necessary to support the potential adoption of a new Compliance Offset protocol by the Board.

Summary of Section 95975(f).

Existing section 95975(f) was renumbered to section 95975(g).

New section 95975(f) is added to clarify that ARB or the OPR must review the listing information for completeness.

Rationale for Section 95975(f).

This change is required to accommodate additional requirements and support a new numbering structure.

The new text is necessary for implementation purposes and to provide consistent requirements for all OPRs for this review process.

Summary of Section 95975(g).

Existing section 95975(f) was renumbered to section 95975(g). Existing section 95975(f), now section 95975(g), is modified to clarify the process for how ARB and OPRs process listing applications.

Rationale for Section 95975(g).

This change is required to accommodate additional requirements and support a new numbering structure.

The new text is needed to clarify the process that ARB and the OPRs use to approve and deny listing applications, and how the OPO and APDs are notified of ARB and the OPRs determinations.

Summary of Section 95975(h).

Existing section 95975(g) was renumbered to section 95975(h). Existing section 95975(g), now section 95975(h), is modified to require that projects list within one year of the Offset Project Commencement date or within one year of meeting the requirements of section 95975(l).

Rationale for Section 95975(h).

This change is required to accommodate additional requirements and support a new numbering structure.

The new text is needed to limit the timeframe between project commencement and listing adds another feature to the program to ensure offset projects are developed for purposes of reducing GHG's in a conservative business-as-usual scenario.

Summary of Section 95975(i).

Existing section 95975(h) was renumbered to section 95975(i). Existing section 95975(h), now section 95975(i), is modified to clarify the scope of an OPR's review of the listing information in an initial crediting period.

Rationale for Section 95975(i).

This change is required to accommodate additional requirements and support a new numbering structure.

The new text is needed to clarify the scope of listing review. Offset Project Registries do not assess whether offset projects meet the additionality requirements of the Regulation and the applicable COP. The scope of Offset Project Registry review is

limited to assessing the listing for completeness. Verification bodies will assess whether the project meets the additionality criteria during the first offset verification of the offset project under a COP.

Summary of Section 95975(j).

Existing section 95975(i) was renumbered to section 95975(j).

Rationale for Section 95975(j).

This change is required to accommodate additional requirements in this section and support a new numbering structure.

Summary of Section 95975(k).

Existing section 95975(j) was renumbered to section 95975(k). Existing section 95975(j), now section 95975(k), is modified to clarify the scope of an OPR's review of the listing information in renewed crediting period.

Rationale for Section 95975(k).

This change is required to accommodate additional requirements in this section and support a new numbering structure.

The new text is needed to clarify the scope of listing review. Offset Project Registries do not assess whether offset projects meet the additionality requirements of the Regulation and the applicable COP. The scope of Offset Project Registry review is limited to assessing the listing for completeness. Verification bodies will assess whether the project meets the additionality criteria during the first offset verification of the offset project under a COP.

Summary of Section 95975(l)(1).

Existing section 95975(l)(1) is modified to specify that a Tribe, in addition to meeting the other offset project listing requirements, must also enter into a limited waiver of sovereign immunity with ARB related to the Tribe's participation in the Cap-and-Trade Program prior to the listing of any offset project being developed on lands related to the Tribe as specified in section 95973(d).

Rationale for Section 95975(l)(1).

This change is needed to ensure ARB's ability to pursue judicial remedies, if necessary, regarding these offset projects when enforcing the requirements of the compliance offset protocols and the Regulation. The proposed amendment to section 95975(l)(1) clarifies that Tribal governments, as sovereign public entities, will be treated the same

as other public entities under California law. This amendment is made pursuant to Board direction and to clarify ARB's intent for purposes of relief under a limited waiver of sovereign immunity.

Summary of Section 95975(m).

New section 95975(m) is added to prohibit changes to the listing information once it is approved.

Rationale for Section 96975(m).

This section is added to ensure that the OPO or APD does not change the listing information after the listing is approved because the listing is an enforceable document that may only be changed under limited circumstances. If an OPO changes during the crediting period it is necessary that they update the listing information so the identity of the OPO is publicly available.

Summary of Section 95975(m)(1).

New section 95975(m)(1) is added to only allow a new OPO to make changes to the listing information if the OPO changes during a crediting period.

Rationale for Section 96975(m)(1).

This section is added to require new OPOs to submit updated information about themselves, if the OPO changes during the crediting period. Changes to the OPO are the only information that is allowed to be updated after the listing information is submitted. The project information must remain the same to ensure the project is still eligible for the compliance offset program.

Summary of Section 95975(m)(2).

New section 95975(m)(2) is added to require a new OPO to resubmit the listing attestations if the OPO changes during a crediting period.

Rationale for Section 96975(m)(2).

This section is added to require new OPOs to submit the attestations required for listing to ensure that ARB has enforcement authority over the new OPO.

Summary of Section 95975(n).

Existing section 95975(k) was renumbered to section 95975(n). Existing section 95975(k), now section 95975(n), is modified to fix a section reference and to add a reference to the applicable COP.

Rationale for Section 95975(n).

This change is required to accommodate additional requirements and support a new numbering structure.

The new text is needed to ensure that the references in the Regulation are correct. The applicable COP is referenced because each COP has requirements for crediting period renewal that must be met, in addition to those requirements in the Regulation.

Summary of Section 95975(o).

New section 95975(o) is added to include a process and requirements for transferring offset projects between OPRs.

Rationale for Section 95975(o).

This section is needed to provide a uniform process and associated requirements for transferring offset projects between OPRs. The existing Regulation lacked requirements for transferring offset projects between OPRs.

Summary of Section 95975(o)(1).

New section 95975(o)(1) is added to provide the project status that must be reflected on the OPRs public webpage when offset projects transfer between OPRs.

Rationale for Section 95975(o)(1).

This section is needed to indicate what the offset project's status is on the OPR's public webpage to provide transparency. This status allows the public to know that the offset project has been transferred to another OPR, but is still an active project.

Summary of Section 95975(o)(1)(A).

New section 95975(o)(1)(A) is added to specify that if only the listing documents are submitted before the offset project is transferred to another OPR, the original OPR must maintain the listing documents on its public website for a period of one year..

Rationale for Section 95975(o)(1)(A).

This section is needed to specify the timeframe that listing information must be made public after an offset project transitions to another OPR. This provides the public with transparency regarding the offset project transfer.

Summary of Section 95975(o)(1)(B).

New section 95975(o)(1)(B) is added to specify that if a Offset Verification Statement is submitted before the offset project is transferred to another OPR, the original OPR must maintain all project documents on its website for the duration of the project lifetime.

Rationale for Section 95975(o)(1)(B).

This section is needed to specify the timeframe all documents must be made public after a transfer. If offset verification services have occurred or any offset credits have been issued to the offset project that information must remain on the public webpage of the original OPR that approved the offset verification and issuance of offset credits. This provides the public with information related to verification and issuances for previous Reporting Periods before the offset project switched OPRs.

Summary of Section 95975(o)(1)(C).

New section 95975(o)(1)(C) is added to require that the new OPR retain the original listing information for the offset project when the offset project transfers between OPRs. Also, the new text stipulates that the offset project commencement date may change if the offset project has not yet undergone initial offset verification services.

Rationale for Section 95975(o)(1)(C).

This section is needed to ensure that the OPO or APD do not change the listing information when transferring an offset project. This prohibition will prevent OPOs and APDs from transferring the offset project to another OPR just to change the listing information for the project. In some cases during initial offset verification activities, the offset verification team will find that the Offset Project Commencement date was reported incorrectly by the OPO or APD. In this case, this provision would allow the Offset Project Commencement date to be updated in the Offset Project Data Report based on the offset verification team's findings.

Summary of Section 95975(o)(2).

New section 95975(o)(2) is added to specify the OPO or APD must provide the original listing information to the new OPR for listing. This provision only allows the OPO or APD to make changes to the listing documentation if the OPO has changed as specified in section 95975(m).

Rationale for Section 95975(o)(2).

This section is needed to specify that the OPO or APD must provide the original listing documentation to the new OPR when the offset project is transferred between OPRs.

This will ensure that the new OPR has the originally approved documentation because the listing is an enforceable document that may only be changed under limited circumstances. If an OPO changes during the crediting period it is necessary they update the listing information so the identity of the OPO is publicly available.

Summary of Section 95975(o)(3).

New section 95975(o)(3) is added to prohibit the OPO or APD from transferring an offset project to another OPR during offset verification services.

Rationale for Section 95975(o)(3).

This section is needed to ensure that ARB and the OPR are able to plan audits of offset verification services. If an OPO or APD transfers an offset project during a period where offset verification services are already being conducted, the new OPR will not be able to audit the offset project from the beginning of the offset verification process.

Section 95976. Monitoring, Reporting, and Record Retention Requirements for Offset Projects.

Summary of Section 95976(c)(3).

Existing section 95976(c)(3) is modified to support the addition of a Compliance Offset Protocol to section 95976(c).

Rationale for Section 95976(c)(3).

This change is non-substantive and needed to support the inclusion of an additional Compliance Offset Protocol in this section.

Summary of Section 95976(c)(4).

Existing section 95976(c)(3) is modified to support the addition of a Compliance Offset Protocol to section 95976(c)..

Rationale for Section 95976(c)(4).

This change is non-substantive and needed to support the inclusion of an additional Compliance Offset Protocol in this section.

Summary of Section 95976(c)(5).

New section 95976(c)(5) is added to include the potential Mine Methane Capture Projects Compliance Offset Protocol which staff is proposing for Board adoption.

Rationale for Section 95976(c)(5).

This change is necessary to support the potential adoption of a new Compliance Offset protocol by the Board.

Summary of Section 95976(d).

Existing section 95976(d) is modified to clarify the timing for submitting Offset Project Data Reports. In addition, this section is modified to clarify the requirements for submitting Offset Project Data Reports for ozone depleting substances (ODS) projects.

Rationale for Section 95976(d).

This change is needed to clarify that an Offset Project Data Report must be submitted once for each Reporting Period instead of annually. This clarification is necessary to provide consistent terminology throughout the Regulation. This section is also modified to clarify that only one Offset Project Data Report may be submitted for ODS projects and that the data report may only cover up to 12 months of data. The requirements for reporting for ODS projects in this section are aligned with the intent of the language in the Ozone Depleting Substances Compliance Offset Protocol.

Summary of Section 95976(d)(3).

Existing section 95976(d)(3) is modified to support the addition of a Compliance Offset Protocol to section 95976(d).

Rationale for Section 95976(d)(3).

This change is non-substantive and needed to support the inclusion of an additional Compliance Offset Protocol in this section.

Summary of Section 95976(d)(4).

Existing section 95976(d)(3) is modified to support the addition of a Compliance Offset Protocol to section 95976(d).

Rationale for Section 95976(d)(4).

This change is non-substantive and needed to support the inclusion of an additional Compliance Offset Protocol in this section.

Summary of Section 95976(d)(5).

New section 95976(d)(5) is added to include the potential Mine Methane Capture Projects Compliance Offset Protocol which staff is proposing for Board adoption.

Rationale for Section 95976(d)(5).

This change is necessary to support the potential adoption of a new Compliance Offset Protocol by the Board.

Summary of Section 95976(d)(6).

Existing section 95976(d)(5) was renumbered to section 95976(d)(6). Existing section 95976(d)(5), now section 95976(d)(6), is modified to use consistent terminology throughout the Regulation and to require the attestations associated with reporting be submitted to ARB and/or the OPR at the time the Offset Project Data Report is submitted.

Rationale for Section 95976(d)(6).

This change is required to accommodate additional requirements and support a new numbering structure.

The new text is necessary to ensure that consistent terminology is used throughout out the Regulation and to streamline OPR and ARB procedures when processing information related to an offset project.

Summary of Section 95976(d)(7).

Existing section 95976(d)(6) was renumbered to section 95976(d)(7).

Rationale for Section 95976(d)(7).

This change is required to accommodate additional requirements and support a new numbering structure.

Summary of Section 95976(d)(8).

Existing section 95976(d)(7) was renumbered to section 95976(d)(8).

Rationale for Section 95976(d)(8).

This change is required to accommodate additional requirements and support a new numbering structure.

Section 95977. Verification of GHG Emission Reductions and GHG Removal Enhancements from Offset Projects.

Summary of Section 95977(b).

Existing section 95977(b) is modified to clarify the timing requirements for verification of non-sequestration offset projects. In addition, this section is also modified to allow for the deferment of verification for projects that produce an Offset Project Data Report with zero emission reductions, until a report is submitted with greater than zero emission reductions.

Rationale for Section 95977(b).

This change is necessary to clarify when small non-sequestration projects with less than 25,000 metric tons CO2e of reductions in a single Reporting Period would require verification.

This change is also necessary to allow an OPO or APD to defer verification of a non-sequestration offset project in years where no reductions are achieved. This will allow OPOs and APDs to not have to contract for verification services in years where there are no reductions to be verified and no offset credits to be issued.

Summary of Section 95977(c).

Existing section 95977(c) is modified to clarify that all sequestration offset projects must be verified after the first Reporting Period. In addition, this section is modified to allow urban forest offset projects to defer the second verification for twelve years, similar to a reforestation project.

Rationale for Section 95977(c).

This change is needed to clarify that for all sequestration projects an initial verification is required after the first Reporting Period. Thereafter, the OPO or APD may defer offset verification for up to six years. This change aligns with the requirements in section 95977.1(b)(3)(D).

An additional change in needed to allow urban forest offset projects that successfully complete the first verification, to defer the second verification for up to 12 years. Since urban forest offset projects will have minimal sequestration in the early years, similar to reforestations projects, this provision will allow OPOs and APDs to not contract for verification services in those years.

Summary of Section 95977(d).

Existing section 95977(d) is modified to clarify that for each Offset Project Data Report one Offset Verification Statement and one detailed verification report must be submitted by the verification body. This section is also modified to expand the verification timeframe for 9 to 11 months.

Rationale for Section 95977(d).

This change is needed to ensure that ARB and the OPR have a verification report detailing the verification body's findings for each Offset Project Data Report that the OPO or APD submits. This will allow ARB to have a third-party verification body's opinion and detailed findings for each period of reporting.

The additional modification is needed to change the length of time allowed for offset verification services from 9 to 11 months to allow more flexibility for complex offset projects, such as U.S. forestry projects, to meet the verification deadline.

Section 95977.1. Requirements for Offset Verification Services.

Summary of Section 95977.1(a).

Existing section 95977.1(a) is modified to clarify the requirements for the rotation of verification bodies and to include consistent terminology within the Regulation. In addition, this section is modified to apply the rotation requirements between both the OPO and APD, if there is a designated APD, and both the verification body and individual offset verifiers.

Rationale for Section 95977.1(a).

This change is needed to use the consistent terminology of Reporting Period throughout the Regulation. Reporting Period is referred to as many different terms throughout the Regulation. This change is also needed to add in additional references to sections 95977.1(a)(1) and (a)(2), which include specific requirements for rotation of verification bodies as they apply to ODS projects and reforestation and urban forest offset projects.

In addition, this change in necessary to clarify that the rotation is applied to the APD and to individual offset verifiers to minimize any biases and avoid familiarity or complacency between those working on offset projects and individual verifiers.

Summary of Section 95977.1(a)(1).

New section 95977.1(a)(1) is added to include requirements for rotation of verification bodies and offset verifiers that can be specifically applied to ODS projects.

Rationale for Section 95977.1(a)(1).

This section is needed to differentiate the rotation of verification body and offset verifier requirements between other project types and ODS projects. ODS projects are very short in duration and each Offset Project Data Report submitted is considered one project. The original rotation requirements in the Regulation did not apply to ODS projects because they are not continuous projects with multiple Reporting Periods.

Summary of Section 95977.1(a)(2).

New section 95977.1(a)(2) is added to allow verification bodies and offset verifiers for reforestation and urban forest offset projects to verifier up to13 Offset Project Data Reports if the second verification has been deferred for up to 12 years.

Rationale for Section 95977.1(a)(2).

This section is needed because reforestation and urban forest offset projects may defer the second offset verification services for up to 12 years and the original six year rotation requirements did not cover this scenario.

Summary of Section 95977.1(b)(1).

Existing section 95977.1(b)(1) is modified to specify which services are considered offset verification services and to require submittal of the Notice of Offset Verification Services (NOVS) to ARB and an Offset Project Registry within 30 days prior to beginning offset verification services.

Rationale for Section 95977.1(b)(1).

This change is needed to clarify which services may not be conducted prior to the submittal of a NOVS. This change is also needed so that ARB and the OPR have more time to plan their audit activities.

Summary of Section 95977.1(b)(2).

Existing section 95977.1(b)(2) is modified to clarify a typographical error. In addition, the timing for the requirements in this section are clarified and staff added new text that requires verification bodies to respond within 10 calendar days to requests from ARB and an OPR.

Rationale for Section 95977.1(b)(2).

This change is needed to fix a typographical error to clarify that this section refers to the NOVS and not the conflict of interest self-evaluation. In addition, this change is needed

to ensure that verification bodies respond to requests by ARB and the OPR in a timely manner when revisions are requested.

Summary of Section 95977.1(b)(3)(A).

Existing section 95977.1(b)(3)(A) is modified to specify that the OPO or APD must submit the information necessary to develop the Offset Verification Plan to the verification body.

Rationale for Section 95977.1(b)(3)(A).

This change is needed to clarify that the OPO or APD submits the information necessary to develop the Offset Verification Plan to the offset verification team and not ARB or the OPR.

Summary of Section 95977.1(b)(3)(B).

Existing section 95977.1(b)(3)(B) is modified to clarify that the requirements listed in this section are related to the Offset Verification Plan.

Rationale for Section 95977.1(b)(3)(B).

This change is needed to clarify that the requirements listed in this section must be included in the Offset Verification Plan by the verification body.

Summary of Section 95977.1(b)(3)(C).

Existing section 95977.1(b)(3)(C) is modified to clarify that activities associated with contracting and bidding are not considered part of offset verification services.

Rationale for Section 95977.1(b)(3)(C).

This change is also necessary to clarify that activities to secure a contract for offset verification are not part of offset verification services, and can therefore be conducted before submitting an NOVS.

Summary of Section 95977.1(b)(3)(D).

Existing section 95977.1(b)(3)(D) is modified to use consistent technology throughout the Regulation. The new text is added to clarify the timing requirements for conducting site visits and to require that a site visit is required after the first Reporting Period in each crediting period.

Rationale for Section 95977.1(b)(3)(D).

This change is needed to use the consistent terminology of Reporting Period throughout the Regulation. Reporting Period is referred to as many different terms throughout the Regulation. This change is also needed to clarify that a site visit must be conducted after the Offset Project Data Report is submitted. This is important because the purpose of offset verification services and the site visit is for the offset verification team to verify accuracy and conformance of the OPO or APD's Offset Project Data Report. Additionally, this change is needed to require a site visit after the first Reporting Period of each crediting period. This is necessary to validate that the offset project meets the eligibility criteria in the Regulation and the applicable COP.

Summary of Section 95977.1(b)(3)(D)(1.).

Existing section 95977.1(b)(3)(D)(1.) is modified to clarify that the initial site visit occurs after the first Reporting Period.

Rationale for Section 95977.1(b)(3)(D)(1.).

This change is needed to be consistent with the changes made to section 95977.1(b)(3)(D), which requires a site visit after the first Reporting Period of each crediting period. This site visit will help the offset verification team validate that the offset project meets the eligibility criteria in the Regulation and the applicable COP.

Summary of Section 95977.1(b)(3)(D)(1.)(a.).

Existing section 95977.1(b)(3)(D)(1.)(a.) is modified to clarify the offset project must meet the requirements of the Regulation and the relevant COP.

Rationale for Section 95977.1(b)(3)(D)(1.)(a.).

This change is needed to clarify that the offset verification team must assess that the offset project meets the requirements for additionality as required under the applicable COP. The intent of this provision is unchanged.

Summary of Section 95977.1(b)(3)(D)(1.)(f.).

Existing section 95977.1(b)(3)(D)(1.)(f.) is modified to include chain of custody to the list of criteria that must be assessed for validating an offset project during the initial verification.

Rationale for Section 95977.1(b)(3)(C)(1.)(f.).

This change is needed to ensure that the offset verification team reviews the chain of custody information as part of the validation step during the first full verification. Chain

of custody requirements were moved to section 95977.1(b)(3)(D)(1.)(f.) from 95977.1(b)(3)(G)(3.)(f.) because it is an eligibility requirement that must be met and may not be sampled.

Summary of Section 95977.1(b)(3)(D)(1.)(g.).

New section 95977.1(b)(3)(D)(1.)(g.) is added to require offset verification teams to issue an Adverse Offset Verification Statement if any of the eligibility criteria cannot be met.

Rationale for Section 95977.1(b)(3)(D)(1.)(g.).

This section is needed to make explicit that there is a validation step associated with the first full offset verification for an offset project. The offset verification team must ensure that the all of the requirements for eligibility are met before the project is eligible to be issued registry and ARB offset credits. Because all eligibility criteria must be met, they may not be sampled by the offset verification team.

Summary of Section 95977.1(b)(3)(D)(2.).

Existing section 95977.1(b)(3)(D)(2) is modified to clarify that the initial site visit must be conducted after the first Reporting Period.

Rationale for Section 95977.1(b)(3)(D)(2.).

This change is needed to clarify that the initial site visit follows the first Reporting Period of each crediting period.

Summary of Section 95977.1(b)(3)(F).

Existing section 95977.1(b)(3)(F) is modified to fix a typographical error.

Rationale for Section 95977.1(b)(3)(F).

This change is needed to fix a typographical error and to clarify that the OPO and APD must make the project GHG emissions documentation available, not the annual GHG emissions.

Summary of Section 95977.1(b)(3)(G)(3.)(e.).

Existing section 95977.1(b)(3)(G)(3.)(e.) is modified to support removing chain of custody from the uncertainty risk narrative.

Rationale for Section 95977.1(b)(3)(G)(3.)(e.).

This change is needed to remove chain of custody from the qualitative narrative of uncertainty risk assessment.

Summary of Section 95977.1(b)(3)(G)(3.)(f.).

Existing section 95977.1(b)(3)(G)(3.)(f.) is moved to section 95977.1(b)(3)(C)(1.)(f.).

Rationale for Section 95977.1(b)(3)(G)(3.)(f.).

This change is needed because the chain of custody requirements must be verified as part of evaluating the eligibility criteria and may not be sampled.

Summary of Section 95977.1(b)(3)(G)(3.)(g.).

Existing section 95977.1(b)(3)(G)(3.)(g.) is renumbered to section 95977.1(b)(3)(G)(3.)(f.).

Rationale for Section 95977.1(b)(3)(G)(3.)(g.).

This change is necessary because the numbering structure of this section changed due to the deletion of existing section 95977.1(b)(3)(G)(3.)(f.).

Summary of Section 95977.1(b)(3)(K).

Existing section 95977.1(b)(3)(K) is modified to clarify the timing for when the sampling plan must be made available to ARB or the OPR. In addition, this section is modified to clarify that documentation related to the verification must be retained by the verification body for 15 years.

Rationale for Section 95977.1(b)(3)(K).

This change is needed to clarify that verification bodies have 10 calendar days to submit the sampling plan. There was confusion as to whether the 10 days were calendar or working days. In addition, this change is needed to ensure that all verification-related information is retained to enable ARB audits, and that there is clear, documented evidence upon which a verification body made its findings when it issued a detailed verification report.

Summary of Section 95977.1(b)(3)(L)(4.).

Existing section 95977.1(b)(3)(L)(4.) is modified to clarify that the calculations submitted by the OPO or APD must be compared by the offset verification team, and the data check narrative must contain an explanation of how the data checks were calculated.

Rationale for Section 95977.1(b)(3)(L)(4.).

This change is needed to clarify that verification bodies must compare the calculations they get for the data checks to the calculations conducted by the OPO for those same data points. This is changed in response to stakeholder comments that the provision was not clear. In addition, this change is needed to require the verification body to submit a narrative in the detailed verification report of how the data checks were calculated. This will allow ARB and the OPR to better understand the verification process and how the data checks were conducted.

Summary of Section 95977.1(b)(3)(M).

Existing section 95977.1(b)(3)(M) is modified to require the OPO or APD to make all possible improvements or corrections identified by the verification body.

Rationale for Section 95977.1(b)(3)(M).

This change is needed to prevent the intentional overstatement of GHG emission reduction or removal enhancements. OPOs and APDs must make all possible corrections before offset verification services may be finalized to ensure that the best and most accurate offset project data is used for calculating the GHG reductions and GHG removal enhancements that may ultimately be issued offset credits. If the OPO or APD does not make all possible improvements or corrections the verification body must issue and Adverse Offset Verification Statement.

Summary of Section 95977.1(b)(3)(N).

Existing section 95977.1(b)(3)(N) is modified to clarify the requirements for data checks as they relate to determining offset material misstatement.

Rationale for Section 95977.1(b)(3)(N).

This change is needed to clarify that the offset verification must use its calculation comparisons derived as part of the data checks to assess offset material misstatement, and not the calculation of total GHG reductions or GHG removal enhancements. This has been a point of confusion for offset verifiers.

Summary of Section 95977.1(b)(3)(P).

Existing section 95977.1(b)(3)(P) is modified to clarify the timeframe for which offset material misstatement is applied.

Rationale for Section 95977.1(b)(3)(P).

This change is needed to clarify that offset material misstatement is applied to net GHG reductions and GHG removal enhancements achieved for each Reporting Period.

Summary of Section 95977.1(b)(3)(Q).

Existing section 95977.1(b)(3)(Q) is modified to update the offset material misstatement calculation as it relates to offset projects. The clarifications make the equation and terms clearer to ensure that verification bodies are calculating offset material misstatement correctly. When calculating the numerator of the equation the verification body must include the positive or negative impact that the discrepancy, omission, or misreporting will have on the total GHG reductions and GHG removal enhancements. Whether it is a positive or a negative impact will be determined based on the type of offset project (non-sequestration or sequestration) and whether the value is derived from the project emissions or project baseline emissions.

Rationale for Section 95977.1(b)(3)(Q).

This change is needed to clarify the inputs into the equation and to fix technical errors in the equation. The definition for "total reported emissions" was modified to clarify that the denominator of the equation includes the total GHG reductions and GHG removal enhancements reported by the OPO or APD.

Summary of Section 95977.1(b)(3)(R)(1.).

Existing section 95977.1(b)(3)(R)(1.) is modified to clarify the requirements for issuing Offset Verification Statements.

Rationale for Section 95977.1(b)(3)(R)(1.).

This change is needed to clarify that the verification body must issue an Offset Verification Statement for each Offset Project Data Report.

Summary of Section 95977.1(b)(3)(R)(4.)(a.).

Existing section 95977.1(b)(3)(R)(4.)(a.) is modified to clarify the requirements for issuing detailed verification reports. In addition, this section is modified to clarify the requirements for data checks and offset material misstatement as they relate to the detailed verification report.

Rationale for Section 95977.1(b)(3)(R)(4.)(a.).

This change is needed to clarify that the verification body must issue a detailed verification report for each Offset Project Data Report. This change is also needed to

require the verification body to submit a narrative in the detailed verification report of how the data checks were calculated and explain the level of detail required for the offset material misstatement calculation. This will allow ARB and the OPR to better understand the data checks and offset material misstatement calculation conducted.

Summary of Section 95977.1(b)(3)(R)(4.)(c.).

Existing section 95977.1(b)(3)(R)(4.)(c.) is modified to clarify the types of non-conformances that are eligible for issuing a Qualified Positive Offset Verification Statements.

Rationale for Section 95977.1(b)(3)(R)(4.)(c.).

This change is needed to clarify that only non-conformances as specified in the definition of Qualified Positive Offset Verification Statement are allowed for issuing a Qualified Positive Offset Verification Statement. This will ensure that verification bodies do not attempt to issue a Qualified Positive Offset Verification Statement for a non-conformance that is not related to quantification, monitoring, or metering requirements.

Summary of Section 95977.1(b)(3)(R)(4.)(d.).

Existing section 95977.1(b)(3)(R)(4.)(d.) is modified to clarify the timing for the final discussion between the offset verification team and the OPO or APD.

Rationale for Section 95977.1(b)(3)(R)(4.)(d.).

This change is needed to ensure that the offset verification team has a final discussion to resolve any outstanding issues with the OPO or APD before the verification body submits the Offset Verification Statement to ARB or the OPR. This will help resolve any issues that may arise once ARB or the OPR review the documentation.

Summary of Section 95977.1(b)(3)(R)(4.)(f.).

Existing section 95977.1(b)(3)(R)(4.)(f.) is modified to include a reference to the applicable COP.

Rationale for Section 95977.1(b)(3)(R)(4.)(f.).

This change is needed to include a reference to the applicable COP because there may be additional project specific requirements in the applicable COP related to offset verification. The requirements in the applicable COP must also be met.

Section 95978. Offset Verifier and Verification Body Accreditation.

Summary of Section 95978(a).

Existing section 95978 is renumbered to section 95978(a). Existing section 95978, now section 95978(a) is modified to clarify that the verification body and offset verifier accreditation process for the compliance offset program is separate from MRR accreditation.

Rationale for Section 95978(a).

This change is necessary to alleviate confusion that MRR accreditation satisfies the requirements of this Regulation, and to accommodate a new numbering structure. This change is also necessary to ensure verification bodies are accredited and trained in the compliance offset program.

Summary of Section 95978(b).

New section 95978(b) is added to clarify how subcontractor requirements in MRR apply to the offset program.

Rationale for Section 95978(b).

This section is needed to ensure that the requirements in MRR are applied correctly to the offset program because the reference to MRR identifies the reporting entity which does not exist in the offset program.

Summary of Section 95978(c).

New section 95978(c) is added to include requirements related to ARB audits of ARB-accredited verification bodies.

Rationale for Section 95978(c).

This section is needed to ensure that ARB has access to relevant materials during an audit.

Summary of Section 95978(d)
Section 95978(d) is added to clarify that technical experts may perform certain limited tasks as part of an offset verification

Rationale for Section 95978(d)
This section is necessary because ARB accredited offset verifiers require technical expertise beyond their own when performing a verification. These cases require the ARB accredited offset verifiers to engage technical experts, but the technical experts have not been accredited by ARB. This section allows those technical experts to

perform services required to aid the verification services, but requires that unaccredited technical experts be supervised at all times during a verification.

Summary of Section 95978(d)(1)
Section 95978(d)(1) is added to require that any technical experts must be identified on the Notice of Offset Verification Services and be considered when evaluating conflict of interest

Rationale for Section 95978(d)(1)
This section is necessary because conflict of interest must be evaluated against all personnel involved with the offset verification to maintain the integrity of the compliance offset program.

Summary of Section 95978(d)(2)
Section 95978(d)(2) is added to require that technical experts must be under the direct supervision of an ARB accredited offset verifier at all time.

Rationale for Section 95978(d)(2)
This section is necessary because the ARB accredited verifier and verification body are ultimately responsible for the actions of the technical expert. All decisions need to be made by an ARB accredited verifier in consultation with the technical expert. Direct supervision is required to ensure an ARB accredited verifier remains responsible for all verification services.

Summary of Section 95978(d)(3)
Section 95978(d)(3) is added to clarify that technical experts are very limited in the roles they may play on an offset verification.

Rationale for Section 95978(d)(3)
This section is necessary because the ARB accredited verifier and verification body are the ones ultimately responsible for the actions of the technical expert. All decisions need to be made by the ARB accredited verifier in consultation with the technical expert.

Summary of Section 95978(e)
Section 95978(e)) is added to define the term direct supervision.

Rationale for Section 95978(e)
This section is necessary to help define to role of the technical expert in offset verification.

Summary of Section 95978(f)
Section 95978(e)) is added to define the term technical expert.

Rationale for Section 95978(e)
This section is necessary to help define to role of the technical expert in offset verification.

Section 95979. Conflict of Interest Requirements for Verification Bodies for Verification of Offset Project Data Reports.

Summary of Section 95979.

The title of section 95979 is changed to Conflict of Interest Requirements for Verification Bodies and Offset Verifiers for Verification of Offset Project Data Reports.

Rationale for Section 95979.

The title is changed to more accurately reflect the content of the section. The section addresses conflict of interest requirements for both verification bodies and offset verifiers.

Summary of Section 95979(a).

Existing section 95979(a) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable, and any subcontractors working as part of the offset verification team.

Rationale for Section 95979(a).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(1).

Existing section 95979(b)(1) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(1).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2).

Existing section 95979(b)(2) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(F).

Existing section 95979(b)(2)(F) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2)(F).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(G).

Existing section 95979(b)(2)(G) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2)(G).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(J).

Existing section 95979(b)(2)(J) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2)(J).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(L).

Existing section 95979(b)(2)(L) is modified to clarify the name for International Organization for Standardization standard referenced in this section.

Rationale for Section 95979(b)(2)(L).

This change is needed to accurately reflect the name of the International Organization for Standardization standard referenced in this section.

Summary of Section 95979(b)(2)(P).

Existing section 95979(b)(2)(P) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2)(P).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(Q).

Existing section 95979(b)(2)(Q) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2)(Q).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(R).

Existing section 95979(b)(2)(R) is modified to support the regulatory structure for additional provisions in this section.

Rationale for Section 95979(b)(2)(R).

This change is needed to add to the list of areas that result in a high potential conflict of interest.

Summary of Section 95979(b)(2)(S).

Existing section 95979(b)(2)(S) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(2)(S).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(2)(T).

Existing section 95979(b)(2)(T) is modified to include a high level of conflict of interest for work related to verifying TEAP facility requirements.

Rationale for Section 95979(b)(2)(T).

This change is necessary to ensure a verification body is not reviewing work that they previously conducted.

Summary of Section 95979(b)(3).

Existing section 95979(b)(3) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(3).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(b)(4).

Existing section 95979(b)(4) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(b)(4).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(c).

Existing section 95979(c) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(c).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(d).

Existing section 95979(d) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(d).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e).

Existing section 95979(e) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable. This section is also modified to clarify to whom the verification body must submit the conflict of interest self-evaluation. Additionally the section is modified to require the conflict of interest self-evaluation be approved by ARB or the OPR prior to commencing offset verification services.

Rationale for Section 95979(e).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project. This change is also needed to clarify that the conflict of interest self-evaluation must also be submitted to ARB and that offset verification services may not begin until ARB or the OPR approves the conflict of interest self-evaluation. This will ensure that any potential conflicts are evaluated and found before offset verification services begin. If there is a high conflict of interest, the verification body is not allowed to perform the work for the OPO or APD.

Summary of Section 95979(e)(2).

Existing section 95979(e)(2) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(2).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3).

Existing section 95979(e)(3) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(A).

Existing section 95979(e)(3)(A) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(A).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(B).

Existing section 95979(e)(3)(B) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(B).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(B)(1.).

Existing section 95979(e)(3)(B)(1.) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(B)(1.).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(B)(2.).

Existing section 95979(e)(3)(B)(2.) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(B)(2.).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(B)(3.).

Existing section 95979(e)(3)(B)(3.) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable. This section is also modified to change the timeframe that must be assessed for conflict of interest from three years to five years.

Rationale for Section 95979(e)(3)(B)(3.).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project and to make the timeframe for assessing conflict of interest consistent throughout the section.

Summary of Section 95979(e)(3)(B)(4.).

Existing section 95979(e)(3)(B)(4.) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(B)(4.).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(B)(5.).

Existing section 95979(e)(3)(B)(5.) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable. This section is also modified to change the timeframe that must be assessed for conflict of interest from three years to five years.

Rationale for Section 95979(e)(3)(B)(5.).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project and to make the timeframe for assessing conflict of interest consistent throughout the section.

Summary of Section 95979(e)(3)(D).

Existing section 95979(e)(3)(D) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(D).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(e)(3)(E).

Existing section 95979(e)(3)(E) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(e)(3)(E).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(f).

New section 95979(f) is added to include the process and requirements for ARB and OPR approval of conflict of interest self-evaluations.

Rationale for Section 95979(f).

This section is necessary to ensure that there is no conflict of interest before offset verification services begin, and to put a streamlined process is in place for ARB and OPR review of project information.

Summary of Section 95979(f)(1).

New section 95979(f)(1) is added to require ARB or the OPR to review the conflict of interest self-evaluation and to make a determination if it meets the requirements of the Regulation.

Rationale for Section 95979(f)(1).

This section is necessary to ensure that there is a streamlined process is in place for ARB and OPR review of project information. Staff chose 30 calendar days to be consistent with the timeframe for reviewing the NOVS.

Summary of Section 95979(f)(1)(A).

New section 95979(f)(1)(A) is added to require verification bodies to respond within 10 calendar days to requests from ARB and an OPR.

Rationale for Section 95979(f)(1)(A).

This section is needed to ensure that verification bodies respond to requests by ARB and the OPR for revisions to the conflict of interest self-evaluation in a timely manner when revisions are requested.

Summary of Section95979(f)(1)(B) .

New section 95979(f)(1)(B) is added to clarify how ARB and an OPR will treat a high potential conflict of interest.

Rationale for Section 95979(f)(1)(B).

This section is needed to clarify that if ARB or an OPR finds a high potential conflict of interest, the verification body will not be able to provide services for the OPO or APD.

Summary of Section 95979(f)(1)(C).

New section 95979(f)(1)(C) is added to clarify how ARB and an OPR will treat a low potential conflict of interest.

Rationale for Section 95979(f)(1)(C).

This section is needed to clarify that if there is a low potential conflict of interest the verification body may proceed with the offset verification services for the OPO or APD.

Summary of Section 95979(f)(1)(D).

New section 95979(f)(1)(D) is added to clarify how ARB and an OPR will treat a medium potential conflict of interest.

Rationale for Section 95979(f)(1)(D).

This section is needed to clarify that if there is a medium potential conflict of interest ARB or the OPR may allow offset verification services to occur, if based on the mitigation plan and all other factors, an acceptable level of risk exists.

Summary of Section 95979(f)(2).

New section 95979(f)(2) is added to clarify that if the offset project is listed with the OPR, the OPR will make the conflict of interest determination.

Rationale for Section 95979(f)(2).

This section is needed to clarify that even though the conflict of interest self-evaluation is submitted to both ARB and the OPR, the approval or denial of a conflict of interest will

be given by the OPR if the offset project is listed with an OPR. Review of the conflict of interest is one of the administrative functions that ARB has delegated to OPRs.

Summary of Section 95979(g).

Existing section 95979(f) is renumbered to section 95979(g).

Rationale for Section 95979(g).

This change is necessary because the numbering structure of this section changed due to the addition of new section 95979(f).

Summary of Section 95979(g)(1).

Existing section 95979(g)(1) is modified to clarify that the verification body must notify both ARB and the OPR of changes in potential conflict of interest situations.

Rationale for Section 95979(g)(1).

This change is needed to ensure that ARB is also notified of any changes in potential conflict of interest. ARB needs to be aware of all changes to conflict of interest to ensure that offset verification services only occur when there as an acceptable level of risk.

Summary of Section 95979(g)(2).

Existing section 95979(g)(2) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(g)(2).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(g)(3).

Existing section 95979(g)(3) is modified to clarify that the verification body must notify both ARB and the OPR of changes in potential conflict of interest situations.

Rationale for Section 95979(g)(3).

This change is needed to ensure that ARB is also notified of any changes in potential conflict of interest. ARB needs to be aware of all changes to conflict of interest to ensure that verification services only occur when there as an acceptable level of risk.

Summary of Section 95979(g)(3)(A).

Existing section 95979(g)(3)(A) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(g)(3)(A).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(g)(3)(B).

Existing section 95979(g)(3)(B) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(g)(3)(B).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(g)(5).

Existing section 95979(g)(5) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(g)(5).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Summary of Section 95979(h).

Existing section 95979(g) is renumbered to section 95979(h).

Rationale for Section 95979(h).

This change is necessary because the numbering structure of this section changed due to the addition of new section 95979(f).

Summary of Section 95979(h)(2).

Existing section 95979(h)(2) is modified to clarify that the conflict of interest requirements apply to both an Offset Project Operator, and an Authorized Project Designee, if applicable.

Rationale for Section 95979(h)(2).

This change is necessary to ensure that no individuals on the offset verification team have a conflict with any party associated with the offset project.

Section 95979.1 Additional Requirements for Air Quality Management Districts and Air Pollution Control Districts.

Summary of Section 95979.1.

New section 95979.1 is added to include additional requirements for air districts for assessing conflict of interest, including the ability to act as an OPR, OPO, APD, or verification body. However, the air districts may not act in multiple roles for the same offset project.

Rationale for Section 95979.1.

This section is needed to ensure there are no conflict of interests for an air district providing offset verification services and registry services. Given their status as regulatory entities, air districts are unique in comparison to other market participants and may perform multiple roles under the offsets program; but not for the same offset project.

Summary of Section 95979.1(a).

New section 95979.1(a) is added to include additional requirements for air districts for assessing conflict of interest.

Rationale for Section 95979.1(a).

This section is needed to ensure an independent system of review during the issuance of a registry credit resulting from the implementation of an offset project using an ARB Compliance Offset Protocol. .

Summary of Section 95979.1(a)(1).

New section 95979.1(a)(1) is added to include additional requirements for air districts for assessing conflicts of interest.

Rationale for Section 95979.1(a)(1).

This section is needed to ensure an independent system of review during the issuance of a registry credit resulting from the implementation of an offset project using an ARB Compliance Offset Protocol.

Summary of Section 95979.1(a)(1)(A).

New section 95979.1(a)(1)(A) is added to allow air districts to register with ARB's CITSS.

Rationale for Section 95979.1(a)(1)(A).

This section is needed to allow air districts to register in CITSS which is prohibited for all other verification bodies and OPRs that are not government agencies.

Summary of Section 95979.1(a)(1)(B).

New section 95979.1(a)(1)(B) is added to allow air districts to hold compliance instruments.

Rationale for Section 95979.1(a)(1)(B).

This section is needed to allow air districts to hold compliance instruments, which is prohibited for all other verification bodies and OPRs that are not government agencies.

Summary of Section 95979.1(a)(2).

New section 95979.1(a)(2) is added to identify what air districts accredited as offset verifies and/or approved as OPRs may not do.

Rationale for Section 95979.1(a)(2).

This section is needed to ensure an independent system of review during the issuance of a registry credit resulting from the implementation of an offset project using an ARB Compliance Offset Protocol. An independent system of implementation, verification, and project review is consistent with international best practices and existing regulatory and voluntary offset programs.

Summary of Section 95979.1(a)(2)(A).

New section 95979.1(a)(2)(A) is added to prohibit air districts from being an OPO or APD and a verification body for the same offset project.

Rationale for Section 95979.1(a)(2)(A).

This section is needed to ensure an independent system of review during the issuance of a registry credit resulting from the implementation of an offset project using an ARB Compliance Offset Protocol.

Summary of Section 95979.1(a)(2)(B).

New section 95979.1(a)(2)(B) is added to prohibit air districts from being an OPO or APD and an OPR for the same offset project.

Rationale for Section 95979.1(a)(2)(B).

This section is needed to ensure an independent system of review during the issuance of a registry credit resulting from the implementation of an offset project using an ARB Compliance Offset Protocol.

Summary of Section 95979.1(a)(2)(C).

New section 95979.1(a)(2)(C) is added to prohibit air districts from being an OPR and a verification body for the same offset project.

Rationale for Section 95979.1(a)(2)(C).

This section is needed to ensure an independent system of review during the issuance of a registry credit resulting from the implementation of an offset project using an ARB Compliance Offset Protocol.

Section 95980. Issuance of Registry Offset Credits.

Summary of Section 95980(c).

Existing section 95980(c) is modified to clarify that the requirements in the COP would supersede the Regulation for determining the start of the initial crediting period.

Rationale for Section 95980(c).

This change is needed because some COPs have project type specific requirements for the start of the crediting period. If the applicable COP has such requirements, those must be followed and not the more general requirements in this section.

Section 95980.1 Process for Issuance of Registry Offset Credits.

Summary of Section 95980.1(a).

Existing section 95980.1(a) is modified to correct and delete inaccurate references in this section.

Rationale for Section 95980.1(a).

This change is needed to ensure that correct references are used in this provision.

Summary of Section 95980.1(c).

Existing section 95980.1(c) is modified to delete inaccurate references in this section.

Rationale for Section 95980.1(c).

This change is needed to ensure that correct references are used in this provision.

Summary of Section 95980.1(d).

New section 95980.1(d) is added to allow an OPR to request additional information for the issuance of registry offset credits from the OPO, APD, or verification body as needed, before issuing offset credits.

Rationale for Section 95980.1(d).

This section is needed to allow the OPR to request any additional information from those responsible for the offset project, or those that verified the project, which the OPR deems necessary to the issuance of registry offset credits.

Summary of Section 95980.1(d)(1).

New section 95980.1(d)(1) is added to require the OPR to request any additional information within the 45 day review timeframe.

Rationale for Section 95980.1(d)(1).

This section is needed to clarify that the timeframe of 45 calendar days in section 95980(b) is not extended due to information requests by an OPR. This will ensure that the registry offset credit issuance process will conclude in a specified period of time to support timely information for the market on offset supply.

Summary of Section 95980.1(d)(2).

Section 95980.1(d)(2) is added to include provisions for an OPR to deny issuance of registry offset credits if the requirements of the Regulation are not satisfied. In addition, this section adds a dispute resolution process for an OPO or APD when crediting is denied by the OPR.

Rationale for Section 95980.1(d)(2).

This section is needed to allow OPRs to deny issuance of registry offset credits if the GHG reductions and GHG removal enhancements do not meet the requirements of the Regulation. This section is also needed to provide OPOs or APDs with a mechanism to resolve any issues before a final determination regarding crediting is made by an OPR.

Summary of Section 95980.1(d)(3).

New section 95980.1(d)(3) is added to require the OPR to make a final determination on the OPO or APD petition within 30 days. In addition, this section is added to allow the OPR to ask for additional information from the OPO, APD, or verification body.

Rationale for Section 95980.1(d)(3).

This section is needed to give the OPR adequate time to make a final decision on registry offset credit issuance and to give the OPO and APD a maximum timeframe that may be needed for the OPR review. In addition, this section is needed to allow the OPR to request and review any other materials that may be helpful in making a final issuance determination.

Summary of Section 95980.1(d)(4).

New section 95980.1(d)(4) is added to require that an OPR submit a report to ARB with an explanation of its denial of crediting.

Rationale for Section 95980.1(d)(4).

This section is needed to require that OPRs provide ARB with a report that will assist ARB in its dispute resolution review of the offset project information.

Summary of Section 95980.1(d)(5).

New section 95980.1(d)(5) is added to include a dispute resolution process with ARB, if an OPR denies issuance of registry offset credits.

Rationale for Section 95980.1(d)(5).

This section is needed to provide a mechanism for an OPO or APD to have the project data reviewed by ARB before a final determination is made to deny issuance of registry offset credits. If registry offset credits are not issued, ARB offset credits will also not be issued; therefore, ARB must be the final decision maker for issuance.

Summary of Section 95980.1(d)(6).

New section 95980.1(d)(6) is added to require that an OPR issue registry offset credits if ARB determines that the project meets the requirements in the Regulation.

Rationale for Section 95980.1(d)(6).

This section is needed to provide a mechanism for an OPO or APD to have the project data reviewed by ARB before a final determination is made to deny issuance of registry offset credits. If registry offset credits are not issued, ARB offset credits will also not be issued; therefore, ARB must be the final decision maker for issuance.

Summary of Section 95980.1(e).

Existing section 95980.1(d) is renumbered to section 95980.1(e). Existing section 95980.1(d), now section 95980.1(e) is modified to clarify when an OPR must issue serial numbers for the relevant registry offset credits. This section is also modified to correct and delete inaccurate references in this section.

Rationale for Section 95980.1(e).

This change is necessary because the numbering structure of this section changed due to the addition of new section 95980.1(d) and to ensure that correct references are used in this provision. This change is also needed to clarify that an OPR may create serial numbers at the time of issuance of registry offset credits. For most registries the issuance is simultaneous to the creation of serial numbers.

Section 95981. Issuance of ARB Offset Credits.

Summary of Section 95981(a)(3).

Existing section 95981(a)(3) is modified to clarify that registry offset credits must first be issued before ARB offset credit issuance if an offset project is listed with an OPR.

Rationale for Section 95981(a)(3).

This change is needed to clarify that a project is only required to have registry offset credits issued if an offset project is listed with an OPR.

Summary of Section 95981(b)(3).

Existing section 95981(b)(3) is modified to clarify that both the original and final Offset Project Data Report must be submitted to ARB for issuance of ARB offset credits. This section is also modified to include new section references.

Rationale for Section 95981(b)(3).

This change is needed for ARB to have full documentation when conducting its review to determine whether ARB offset credits should be issued. In addition, this change is needed to correct references in this section due to adding the requirements for the original and final Offset Project Data Reports.

Summary of Section 95981(b)(5).

New section 95981(b)(5) is added to require the OPO or APD to submit a request for ARB offset credit issuance for each Offset Project Data Report.

Rationale for Section 95981(b)(5).

This section is needed to ensure that the OPO and APD submit the correct information to ARB for the issuance of ARB offset credits.

Summary of Section 95981(b)(5)(A).

New section 95981(b)(5)(A) is added to require the OPO to submit the request for issuance of ARB offset credits if any of the ARB offset credits are to be placed into an account other than the OPO's.

Rationale for Section 95981(b)(5)(A).

This section is needed to specify the roles of the OPO and APD in requesting issuance of ARB offset credits. If an OPO is the only party receiving ARB offset credits, the APD may submit the issuance information. However, if the OPO is designating any other party to receive ARB offset credits from the issuance, the OPO must be the one to submit the request for issuance. This ensures that only the OPO has control for the designation of which accounts the ARB offset credits are issued into, and gives the OPO greater protection that the ARB offset credits will be issued into the correct accounts.

Summary of Section 95981(b)(5)(B).

New section 95981(b)(5)(B) is added to specify that Holding Accounts of any party receiving ARB offset credits must be provided in the issuance request and that anyone receiving ARB offset credits must be registered in CITSS.

Rationale for Section 95981(b)(5)(B).

This section is needed so ARB may know which holding accounts to transfer the ARB offset credits to for initial ownership.

Summary of Section 95981(b)(5)(C).

New section 95981(b)(5)(C) is added to include requirements for when the OPO or APD may submit an issuance request to ARB.

Rationale for Section 95981(b)(5)(C).

This section is needed for ease of implementation of the program and to prohibit OPOs or APDs from submitting issuance requests to ARB before registry offset credits have been issued.

Summary of Section 95981(c).

Existing section 95981(c) is added to clarify that the 45 day timeframe for ARB's determination for issuance of ARB offset credits does not start until complete information is received by ARB.

Rationale for Section 95981(c).

This change is needed to provide ARB with adequate time to review offset project information when determining whether to issue ARB offset credits. It may take some time for ARB to receive complete and accurate information from the OPO, APD, verification body, and OPR, and ARB needs the full 45 days to review documentation that is complete and accurate.

Summary of Section 95981(d).

Existing section 95981(d) is modified to clarify that GHG reductions or removal enhancements are credited for the Reporting Period not the Offset Verification Statement.

Rationale for Section 95981(d).

This change is needed to use the consistent terminology of Reporting Period throughout the Regulation. Reporting Period is referred to in many different terms throughout the Regulation.

Summary of Section 95981(e).

Existing section 95981(e) is modified to clarify that the requirements in the relevant COP supersedes the requirements in the Regulation for determining the start of the initial crediting period.

Rationale for Section 95981(e).

This change is needed because some COPs have project type specific requirements for the start of the crediting period. If the applicable COP has such requirements, those must be followed and not the general requirements in this section.

Section 95981.1 Process for Issuance of ARB Offset Credits.

Summary of Section 95981.1(a).

Existing section 95981.1(a) is modified to correct and delete inaccurate references in this section. This section is also modified to clarify that the attestations required by the Regulation must be submitted to ARB or the 15 day timeframe will not begin for issuing ARB offset credits.

Rationale for Section 95981.1(a).

This change is needed to ensure that correct references are used in this provision. This change is also needed to ensure that ARB does not issue any ARB offset credits before the attestations are received. This also allows ARB to have a full 15 days for issuance after receiving the attestations, if they had not been submitted prior to the determination for issuance was made.

Summary of Section 95981.1(c).

Existing section 95981.1(c) is modified to fix grammatical errors and require ARB to notify the OPO, APD or identified third-party of ARB's intent to issue ARB offset credits within 15 days of making the determination to issue. In addition, this section is modified to correct and delete inaccurate references in this section.

Rationale for Section 95981.1(c).

This change is needed to ensure that correct grammar and references are used in this provision. This section also clarifies that ARB will notify all relevant parties of its intent to issue the ARB offset credits within 15 calendar days of its determination. The 15 calendar days does not refer to the actual issuance of the ARB offset credits, as the provision was originally written.

Summary of Section 95981.1(d)(1).

Existing section 95981.1(d)(1) is modified to correct and delete inaccurate references in this section.

Rationale for Section 95981.1(d)(1).

This change is needed to ensure that correct references are used in this provision.

Summary of Section 95981.1(d)(2).

Existing section 95981.1(d)(2) is modified to require the OPO, APD, verification body, and OPR to respond within 10 calendar days to requests from ARB.

Rationale for Section 95981.1(d)(2).

This section is needed to ensure that the OPO, APD, verification body, and OPR respond to requests by ARB in a timely manner when additional information is requested.

Summary of Section 95981.1(e).

Existing section 95981.1(e) is modified to clarify that OPRs must provide proof of registry offset credit cancelation prior to ARB issuing ARB offset credits.

Rationale for Section 95981.1(e).

This change is needed to ensure that OPRs have retired registry offset credits before ARB offset credits are issued to avoid any potential for double crediting the same GHG emission reductions or removal enhancements.

Summary of Section 95981.1(f).

Existing section 95981.1(f) is modified to correct and delete inaccurate references in this section.

Rationale for Section 95981.1(f).

This change is needed to ensure that correct references are used in this provision.

Section 95982. Registration of ARB Offset Credits.

Summary of Section 95982.

The title of section 95982 is changed to add a period at the end of the title.

Rationale for Section 95982.

The change is needed to be consistent with the other titles in this Regulation.

Summary of Section 95982(b).

Existing section 95982(b) is modified to correct and delete inaccurate references in this section. In addition, this section is modified to remove the reference to serial numbers.

Rationale for Section 95982(b).

This change is needed to ensure that correct references are used in this provision. This change is also needed to remove the reference to serial numbers because ARB will not be publicly releasing serial numbers for ARB offset credits.

Section 95983. Forestry Offset Reversals.

Summary of Section 95983(a)(4).

New section 95983(a)(4) is added to clarify which that ARB offset credits are placed into the Forest Buffer Account (FBA) by Reporting Period.

Rationale for Section 95983(a)(4).

This section is needed to clarify which ARB offset credits placed into the FBA must be from the same Reporting Period for which they are issued. This has always been the intent of the Regulation and this provision makes the requirement more explicit.

Summary of Section 95983(b)(2).

Existing section 95983(b)(2) is modified to clarify how ARB will calculate the quantity of ARB offset credits that will be retired from the FBA in the case of an unintentional reversal.

Rationale for Section 95983(b)(2).

This change is needed to provide transparency so that program participants may understand how ARB will calculate its retirement from the FBA in the event of an unintentional reversal.

Summary of Section 95983(b)(2)(A).

New section 95983(b)(2)(A) is added to clarify how many ARB offset credits will be retired from the FBA in the case of an unintentional reversal for an offset project that came into the program directly under a COP.

Rationale for Section 95983(b)(2)(A).

This section is needed to clarify that in the event of an unintentional reversal ARB offset credits will be retired from the FBA in the amount of metric tons reversed, if the offset project came into the program directly under a COP. This distinction is needed because if a project came into the program directly under a COP, ARB holds the entire buffer account contribution from the offset project. There is no other accounting needed to calculate any early action offset credits that may still be in the Early Action Offset Program's (EAOP) buffer account.

Summary of Section 95983(b)(2)(B).

New section 95983(b)(2)(B) is added to provide the equation for calculating how many ARB offset credits will be retired from the FBA in the case of an unintentional reversal for an offset project that transitioned from an EAOP.

Rationale for Section 95983(b)(2)(B).

This section is needed to clarify that in the event of an unintentional reversal ARB offset credits will be retired from the FBA in the amount calculated according to the equation provided in this section, if the offset project transitioned from an EAOP. This distinction is needed because if a project transitioned from an EAOP, the EAOP may still have early action offset credits in its system that would need to be covered by its buffer account. ARB must account for the early action offset credits that may still be in the EAOP's buffer account so that ARB does not retire ARB offset credits for a reversal of early action offset credits that are not issued in the compliance offset program.

Summary of Section 95983(c)(2).

Existing section 95983(c)(2) is modified to clarify an OPO or APD must contract a verification body for verifying a forest offset project's current carbon stocks in the event of an intentional reversal.

Rationale for Section 95983(c)(2).

This change is needed to allow OPOs or APDs to incorporate the required verification of current carbon stocks into the offset verification services that will be performed for the Reporting Period. This will allow the OPO and APD to manage costs of verification by incorporating the additional verification requirements into regularly scheduled verification.

Summary of Section 95983(c)(3).

Existing section 95983(c)(3) is modified to clarify how many ARB offset credits the forest owner must replace in the case of an intentional reversal.

Rationale for Section 95983(c)(3).

This change is needed to provide transparency so that program participants may understand how ARB will calculate the number of ARB offset credits that the forest owner must replace in the event of an intentional reversal.

Summary of Section 95983(c)(3)(A).

New section 95983(c)(3)(A) is added to clarify how many ARB offset credits must be replaced by the forest owner in the case of an intentional reversal for an offset project that came into the program directly under a COP.

Rationale for Section 95983(c)(3)(A).

This section is needed to clarify that in the event of an intentional reversal the forest owner must replace ARB offset credits in the amount of metric tons reversed, if the offset project came into the program directly under a COP. This distinction is needed because if a project came to the program directly under a COP, ARB has issued all of the offset credits for the entire offset project. There is no other accounting needed to calculate any early action offset credits that may have been issued by the EAOP.

Summary of Section 95983(c)(3)(B).

New section 95983(c)(3)(B) is added to provide the equation for calculating how many ARB offset credits must be replaced by the forest owner in the case of an intentional reversal for an offset project that transitioned from an EAOP.

Rationale for Section 95983(c)(3)(B).

This section is needed to clarify that in the event of an intentional reversal the forest owner must replace ARB offset credits in the amount calculated according to the equation provided in this section, if the offset project transitioned from an EAOP. This distinction is needed because if a project transitioned from an EAOP, the EAOP will have issued early action offset credits for the offset project. ARB must account for the early action offset credits that may have been issued by the EAOP so that the forest owner does not have an obligation to ARB to replace offset credits that are not issued in the compliance offset program.

Summary of Section 95983(c)(3)(C).

Existing section 95983(c)(3)(A) is renumbered to section 95983(c)(3)(C). Existing section 95983(c)(3)(A), now section 95983(c)(3)(C) is modified to include a missing reference.

Rationale for Section 95983(c)(3)(C).

This change is needed to accommodate additional requirements added to this section. This change is also needed to clarify which notification this section is referring to.

Summary of Section 95983(c)(3)(D).

Existing section 95983(c)(3)(B) is renumbered to section 95983(c)(3)(D). Existing section 95983(c)(3)(B), now section 95983(c)(3)(D) is modified to clarify that if the forest owner does not replace ARB offset credits in the amount of tons reversed within 6 months, ARB will retire the credits from the FBA.

Rationale for Section 95983(c)(3)(D).

This change is needed to clarify how many ARB offset credits ARB will retire from the FBA if the forest owner does not replace ARB offset credits in the amount required if there is an intentional reversal. This change is also needed to include references to the new sections of 95983 that explain how the replacement amount is calculated.

Summary of Section 95983(c)(4).

Existing section 95983(c)(4) is modified to clarify how many ARB offset credits the forest owner must replace in the event of an early project termination.

Rationale for Section 95983(c)(4).

This change is needed to provide transparency so that program participants may understand how ARB will calculate the number of ARB offset credits that the forest owner must replace in the event of an early project termination.

Summary of Section 95983(c)(4)(A).

New section 95983(c)(4)(A) is added to clarify how many ARB offset credits must be replaced by the forest owner in the case of an early project termination for an offset project that came to the program directly under a COP. In addition, this section is added to clarify how many ARB offset credits must be replaced by the forest owner in the case of an early project termination for an improved forest management project that came into the program directly under a COP.

Rationale for Section 95983(c)(4)(A).

This section is needed to clarify that in the event of an early project termination the forest owner must replace ARB offset credits in the amount of metric tons reversed, if the offset project came into the program directly under a COP. This distinction is needed because if a project came into the program directly under a COP, ARB has issued all of the offset credits for the entire offset project. There is no other accounting needed to calculate any early action offset credits that may have been issued by the EAOP.

Additionally, this section is needed to clarify that in the event of an early project termination of an improved forest management project the forest owner must replace ARB offset credits in the amount of metric tons reversed multiplied by a compensation rate specified in the COP. The COP includes specific requirements for compensation for improved forest management projects, and those must also be followed.

Summary of Section 95983(c)(4)(B).

New section 95983(c)(4)(B) is added to clarify how many ARB offset credits must be replaced by the forest owner in the case of an early project termination for an offset project that transitioned from an EAOP.

Rationale for Section 95983(c)(4)(B).

This section is needed to clarify that in the event of an early project termination the forest owner must replace ARB offset credits in the amount calculated according to the equation provided in this section, if the offset project transitioned from an EAOP. This distinction is needed because if a project transitioned from an EAOP, the EAOP will have issued early action offset credits for the offset project. ARB must account for the early action offset credits that may have been issued by the EAOP so that the forest owner does not have an obligation to ARB to replace offset credits that are not issued in the compliance offset program.

Summary of Section 95983(c)(4)(C).

New section 95983(c)(4)(C) is added to clarify how many ARB offset credits must be replaced by the forest owner in the case of an early project termination for an improved forest management project that transitioned from an EAOP.

Rationale for Section 95983(c)(4)(C).

This section is needed to clarify that in the event of an early project termination of an improved forest management project the forest owner must replace ARB offset credits

in the amount of metric tons calculated pursuant to section 95983(c)(4)(B) multiplied by a compensation rate specified in the COP. The COP includes specific requirements for compensation for improved forest management projects, and those must also be followed.

Summary of Section 95983(c)(4)(D).

Existing section 95983(c)(4)(A) is renumbered to section 95983(c)(4)(D). Existing section 95983(c)(4)(A), now section 95983(c)(4)(D) is modified to clarify that ARB will notify the forest owner of the number of ARB offset credits they must replace.

Rationale for Section 95983(c)(4)(D).

This change is needed to accommodate additional requirements added to this section and to clarify that ARB is notifying the forest owner of the number of ARB offset credits that must be replaced.

Summary of Section 95983(c)(4)(E).

Existing section 95983(c)(4)(B) is renumbered to section 95983(c)(4)(E). Existing section 95983(c)(4)(B), now section 95983(c)(4)(E) is modified to require the forest owner to replace ARB offset credits in the event of an early project termination instead of ARB retiring credits from the FBA.

Rationale for Section 95983(c)(4)(E).

This change is needed to accommodate additional requirements added to this section. In addition, this change is necessary to require that the forest owner replace ARB offset credits in the event of an early project termination instead of ARB automatically retiring ARB offset credits from the FBA. The FBA must be used as a backstop for making the program whole, rather than the first remedy.

Summary of Section 95983(c)(4)(F).

Existing section 95983(c)(4)(C) is renumbered to section 95983(c)(4)(F). Existing section 95983(c)(4)(C), now section 95983(c)(4)(F) is modified to specify how many ARB offset credits ARB will retire from the FBA if the forest owner does not replace the amount of ARB offset credits required in the event of an early project termination.

Rationale for Section 95983(c)(4)(F).

This change is necessary to accommodate additional requirements added to this section. In addition, this change is needed to specify how many ARB offset credits ARB will retire from the FBA if the forest owner fails to replace some or all of the required

ARB offset credits as a result of an early project termination. The FBA may be used as a backstop to ensure that the program is made whole, if the forest owner does not replace some or all of the required ARB offset credits. The forest owner will still be subject to enforcement action.

Summary of Section 95983(d)(1).

Existing section 95983(d)(1) is modified to correct terminology and clarify that all ARB offset credits, including those issued for early action, will be retired in the event a forest offset project is terminated due to an unintentional reversal.

Rationale for Section 95983(d)(1).

This change is needed to ensure that the correct terminology is used throughout the Regulation in relation to the type of offset credits that are issued by ARB. Early action offset credits are issued by Early Action Offset Programs.

Section 95984. Ownership and Transferability of ARB Offset Credits.

Summary of Section 95984(a).

Existing section 95984(a) is modified to correct and delete inaccurate references in this section.

Rationale for Section 95984(a).

This change is needed to ensure that correct references are used throughout the Regulation.

Section 95985. Invalidation of ARB Offset Credits.

Summary of Section 95985(b)(1).

Existing section 95985(b)(1) is modified to clarify that the timeframe for invalidation of ARB offset credits is eight years unless the requirements in this section are met.

Rationale for Section 95985(b)(1).

This change is needed to clarify the timeframes for which ARB offset credits may be invalidated. This section distinguishes between the timeframe for invalidation for ARB offset credits that are issued according to a COP and ARB offset credits that are issued under an early action quantification methodology. The timeframe in which ARB offset credits issued for early action may be invalidated starts from when ARB issues the offset credits. The timeframe in which ARB offset credits issued under a COP may be

invalidated starts from the date that corresponds to the end of the Reporting Period from which the offset credits were issued.

Summary of Section 95985(b)(1)(A).

Existing section 95985(b)(1)(A) is modified to clarify the requirements that OPOs or APDs must meet to shorten the invalidation timeframe for ODS destruction projects.

Rationale for Section 95985(b)(1)(A).

This change is needed to clarify the requirements that OPOs and APDs of ODS destruction projects must meet in order to shorten the invalidation timeframe from eight to three years.

Summary of Section 95985(b)(1)(A)(1.).

New section 95985(b)(1)(A)(1.) is added to clarify that ODS projects must be verified by a different verification body than the one that did the original verification.

Rationale for Section 95985(b)(1)(A)(1.).

This section is needed to clarify the secondary verification requirements formerly in original section 95985(b)(1)(A) for ODS destruction projects. To shorten the timeframe for ODS projects a second verification must be conducted by a different verification body to ensure that ARB offset credits should have been issued and to ensure that there are no inaccuracies or inconsistencies that were not found during the first full verification. A second full regulatory verification must be conducted for ODS projects because they are not continuous projects and conclude after the initial verification. Without a second full verification there is not another verification body that reviews any information for the project, as is the case for the other project types that are continuous projects and have periodic verification.

Summary of Section 95985(b)(1)(A)(2.).

New section 95985(b)(1)(A)(2.) is added to require the second full verification to occur within three years of ARB offset credit issuance and the verification must result in a positive or qualified positive opinion.

Rationale for Section 95985(b)(1)(A)(2.).

This section is needed to require that the second verification to shorten the timeframe for invalidation for an ODS destruction project be conducted within three years of the issuance of ARB offset credits. Since a second verification would shorten the

invalidation timeframe to three years, the verification needs to occur within those three years and result in a positive or qualified positive verification opinion.

Summary of Section 95985(b)(1)(A)(2.)(a.).

New section 95985(b)(1)(A)(2.)(a.) is added to clarify that the verification body must submit the documentation for the second verification conducted to reduce the invalidation timeframe for ODS destruction projects to the OPR the project with which the project is listed.

Rationale for Section 95985(b)(1)(A)(2.)(a.).

This section is needed so that verification bodies know to submit their verification related materials to the OPR and not ARB.

Summary of Section 95985(b)(1)(A)(2.)(b.).

New section 95985(b)(1)(A)(2.)(b.) is added to require an OPR to review the second verification conducted to reduce the invalidation timeframe for ODS destruction projects and submit a report to ARB with its findings.

Rationale for Section 95985(b)(1)(A)(2.)(b.).

This section is needed to include a process for reviewing the second verification conducted to reduce the invalidation timeframe for ODS destruction projects. The verification related materials will be sent to the OPR for review. This mirrors the process in place for the review of all other full offset verification services conducted in the program. In addition, the OPR must submit a report to ARB detailing its findings of the second verification. This will allow ARB to understand the OPR's review of the materials and its findings.

Summary of Section 95985(b)(1)(A)(2.)(c.).

New section 95985(b)(1)(A)(2.)(c.) is added to require the OPR to review the second verification conducted to reduce the invalidation timeframe for ODS destruction projects within 45 calendar days of receiving it.

Rationale for Section 95985(b)(1)(A)(2.)(c.).

This section is needed so the OPO and APD know when the review of the second verification will be completed. 45 calendar days will give the OPR enough time to review the offset verification and contact the verification body if there are any questions regarding the verification.

Summary of Section 95985(b)(1)(A)(2.)(d.).

New section 95985(b)(1)(A)(2.)(d.) is added to require the OPR to submit its report to ARB on the second verification conducted to reduce the invalidation timeframe for ODS destruction projects within 15 working days of completing its review.

Rationale for Section 95985(b)(1)(A)(2.)(d.).

This section is needed to give the OPR enough time to write its report to ARB and to ensure a timely process.

Summary of Section 95985(b)(1)(A)(3.).

New section 95985(b)(1)(A)(3.) is added to specify how the invalidation timeframe ARB offset credits is reduced to three years, if the requirements for a second regulatory verification are met.

Rationale for Section 95985(b)(1)(A)(3.).

This section is needed to specify that if all the requirements for a second regulatory verification are met, the invalidation timeframe will be reduced to three years.

Summary of Section 95985(b)(1)(A)(3.)(a.).

New section 95985(b)(1)(A)(3.)(a.) is added to specify that ARB offset credits issued under a COP may be invalidated for three years, if the requirements to reduce the invalidation timeframe are met.

Rationale for Section 95985(b)(1)(A)(3.)(a.).

This section is needed to specify that if the requirements to reduce the invalidation timeframe are met, the invalidation timeframe is reduced from eight years to three years, and the invalidation timeframe starts from the date that corresponds to the end of the Reporting Period from which the offset credits were issued.

Summary of Section 95985(b)(1)(A)(3.)(b.).

New section 95985(b)(1)(A)(3.)(b.) is added to specify that ARB offset credits issued for early action may be invalidated for three years, if the requirements to reduce the invalidation timeframe are met.

Rationale for Section 95985(b)(1)(A)(3.)(b.).

This section is needed to specify that if the requirements to reduce the invalidation timeframe are met, the invalidation timeframe is reduced from eight years to three

years, and the invalidation timeframe starts from the date that the ARB offset credits are issued.

Summary of Section 95985(b)(1)(B).

Existing section 95985(b)(1)(B) is modified to clarify the requirements that must be met to shorten the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments.

Rationale for Section 95985(b)(1)(B).

This change is needed to clarify the requirements that OPOs and APDs for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments must meet in order to shorten the invalidation timeframe eight to three years.

Summary of Section 95985(b)(1)(B)(1.).

New section 95985(b)(1)(B)(1.) is added to require that a different verification body be used to verify a subsequent Offset Project Data Report to shorten the invalidation timeframe for U.S. forestry, urban forestry, livestock, and mine methane capture projects.

Rationale for Section 95985(b)(1)(B)(1.).

This section is needed to clarify the subsequent verification requirements formerly in original section 95985(b)(1)(B) for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments. To shorten the timeframe for these project types a different verification body must conduct offset verification services for a subsequent Offset Project Data Report. Because these project types are continuous projects, with periodic verification requirements, a rotation of verifiers will ensure there are no inaccuracies or inconsistencies that were not found during the prior verification.

Summary of Section 95985(b)(1)(B)(2.).

New section 95985(b)(1)(B)(2.) is added to require the second verification body to conduct offset verification services for a subsequent Offset Project Data Report to shorten the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, within three years of ARB offset credit issuance. In addition, this section

is added to require that the subsequent verification conducted by the second verification body result in a positive or qualified positive opinion.

Rationale for Section 95985(b)(1)(B)(2.).

This section is needed to clarify that the second verification body conduct offset verification services for a subsequent Offset Project Data Report to shorten the timeframe for invalidation for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, within three years of the issuance of ARB offset credits. Since the invalidation timeframe would be shortened to three years, the subsequent verification needs to occur within those three years.

Summary of Section 95985(b)(1)(B)(3.).

New section 95985(b)(1)(B)(3.) is added to specify that the invalidation timeframe for ARB offset credits is three years, if the requirements for a subsequent verification are met.

Rationale for Section 95985(b)(1)(B)(3.).

This section is needed to specify that if all the requirements for a subsequent verification are met, the statute of limitations will be reduced to three years.

Summary of Section 95985(b)(1)(B)(3.)(a.).

New section 95985(b)(1)(B)(3.)(a.) is added to specify that ARB offset credits issued under a COP may be invalidated for three years, if the requirements to reduce the statute of limitations are met.

Rationale for Section 95985(b)(1)(B)(3.)(a.).

This section is needed to clarify the process of reducing the invalidation timeframe, such that if the requirements to reduce the statute of limitations are met, the invalidation timeframe is reduced from eight years to three years, and the invalidation timeframe starts from the date that corresponds to the end of the Reporting Period from which the offset credits were issued.

Summary of Section 95985(b)(1)(B)(3.)(b.).

New section 95985(b)(1)(B)(3.)(b.) is added to specify that ARB offset credits issued for early action may be invalidated for three years, if the requirements to reduce the statute of limitations are met.

Rationale for Section 95985(b)(1)(B)(3.)(b.).

This section is needed to clarify the process of reducing the invalidation timeframe, such that if the requirements to reduce the statute of limitations are met, the invalidation timeframe is reduced from eight years to three years, and the invalidation timeframe starts from the date that the ARB offset credits are issued.

Summary of Section 95985(b)(1)(B)(4.).

New section 95985(b)(1)(B)(4.) is added to clarify the requirements that OPOs or APDs must meet to shorten the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed.

Rationale for Section 95985(b)(1)(B)(4.).

This change is needed to clarify the invalidation timeframe process, such that the requirements that OPOs and APDs for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments must meet to shorten the invalidation timeframe from eight years to three years, if the offset project is in the last year of a crediting period that will not be renewed.

Summary of Section 95985(b)(1)(B)(4.)(a.).

New section 95985(b)(1)(B)(4.)(a.) is added to require that a different verification body verify the last Offset Project Data Report to shorten the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed.

Rationale for Section 95985(b)(1)(B)(4.)(a.).

This section is needed to clarify the a second regulatory verification is required to reduce the statute of limitations for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed. To shorten the timeframe a second verification must be conducted by a different verification body to ensure that there are no inaccuracies or inconsistencies that were not found during the first full verification. A second full regulatory verification must be conducted for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a

crediting period that will not be renewed because the project will end and no other verification services will be conducted for the offset project.

Summary of Section 95985(b)(1)(B)(4.)(b.).

New section 95985(b)(1)(B)(4.)(b.) is added to require that the second regulatory verification conducted to shorten the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed, to occur within three years of ARB offset credit issuance. In addition, this section is added to require that the second verification result in a positive or qualified positive opinion.

Rationale for Section 95985(b)(1)(B)(4.)(b.).

This section is needed to require that the second verification to shorten the timeframe for invalidation for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed, to be conducted within three years of the issuance of ARB offset credits. Since a second verification would shorten the invalidation timeframe to three years, the verification needs to occur within those three years.

Summary of Section 95985(b)(1)(B)(4.)(b.)(i.).

New section 95985(b)(1)(B)(4.)(b.)(i.) is added to require the verification body to submit the documentation for the second verification conducted to reduce the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed, to an OPR.

Rationale for Section 95985(b)(1)(B)(4.)(b.)(i.).

This section is needed so that verification bodies know to submit their verification related materials to the OPR and not to ARB.

Summary of Section (b)(1)(B)(4.)(b.)(ii.).

New section 95985(b)(1)(B)(4.)(b.)(ii.) is added to require an OPR to review the second verification conducted to reduce the invalidation timeframe for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed, and submit a report to ARB with its findings.

Rationale for Section 95985(b)(1)(B)(4.)(b.)(ii.).

This section is needed to include a process for reviewing the second verification conducted to reduce the statute of limitations. The verification related materials will be sent to the OPR for review. This mirrors the process in place for the review of all other full offset verification services conducted in the program. In addition, the OPR must submit a report to ARB detailing its findings on the second verification. This will allow ARB to understand the OPR's review of the materials and its findings.

Summary of Section 95985(b)(1)(B)(4.)(b.)(iii.).

New section 95985(b)(1)(B)(4.)(b.)(iii.) is added to require that the OPR review the second verification conducted to reduce the statute of limitations for non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments, that are in the last year of a crediting period that will not be renewed within 45 calendar days of receiving it.

Rationale for Section 95985(b)(1)(B)(4.)(b.)(iii.).

This section is needed so the OPO and APD know when the review of the second verification will be completed. 45 calendar days will give the OPR enough time to review the offset verification statements and contact the verification body if there are any questions regarding the verification. This timeframe also ensures a timely process.

Summary of Section 95985(b)(1)(B)(4.)(b.)(iv.).

New section 95985(b)(1)(B)(4.)(b.)(iv.) is added to require the OPR to submit its report to ARB on the second verification conducted to reduce the invalidation timeframe for U.S. forestry, urban forestry, livestock, and mine methane capture projects that are in the last year of a crediting period that will not be renewed, within 15 working days of completing its review.

Rationale for Section 95985(b)(1)(B)(4.)(b.)(iv.).

This section is needed to give the OPR enough time to write its report to ARB and ensure a timely process.

Summary of Section 95985(b)(1)(B)(5.).

Some text in existing section 95985(b)(1)(B) is moved to new section 95985(b)(1)(B)(5.). New section 95985(b)(1)(B)(5.) is added and modified to identify the COPs and early action quantification methodologies for which a different verification body must conduct offset verification services for a subsequent Offset Project Data Report to reduce the invalidation timeframe.

Rationale for Section 95985(b)(1)(B)(5.).

This section is needed to include the list of COPs that and early action quantification methodologies for which a different verification body must conduct offset verification services for a subsequent Offset Project Data Report to reduce the invalidation timeframe. These include COPs and early action quantification methodologies for the following project types: U.S. forestry, urban forestry, livestock, and mine methane capture projects.

Summary of Section 95985(b)(1)(B)(5.)(a.).

Existing section 95985(b)(1)(B)(1.) is renumbered to new section 95985(b)(1)(B)(5.)(a.).

Rationale for Section 95985(b)(1)(B)(5.)(a.).

This change is needed to accommodate a new numbering structure in this section.

Summary of Section 95985(b)(1)(B)(5.)(b.).

Existing section 95985(b)(1)(B)(2.) is renumbered to new section 95985(b)(1)(B)(5.)(b.). Existing section 95985(b)(1)(B)(2.), 95985(b)(1)(B)(5.)(b.) was modified to accommodate the addition of the COP Mine Methane Capture Projects to this section.

Rationale for Section 95985(b)(1)(B)(5.)(b.).

This change is needed to accommodate the addition of the COP Mine Methane Capture Projects to this section.

Summary of Section 95985(b)(1)(B)(5.)(c.).

Existing section 95985(b)(1)(B)(3.) is renumbered to new section 95985(b)(1)(B)(5.)(c.). Existing section 95985(b)(1)(B)(3.), 95985(b)(1)(B)(5.)(c.) modified to accommodate the addition of the COP Mine Methane Capture Projects to this section.

Rationale for Section 95985(b)(1)(B)(5.)(c.).

This change is needed to accommodate the addition of the COP Mine Methane Capture Projects to this section.

Summary of Section 95985(b)(1)(B)(5.)(d.).

New section 95985(b)(1)(B)(5.)(d.) is added to include the potential COP Mine Methane Capture Projects Protocol which staff is proposing for Board adoption.

Rationale for Section 95985(b)(1)(B)(5.)(d.).

This change is necessary to support the potential adoption of new offset protocols by the Board.

Summary of Section 95985(c)(1).

Existing section 95985(c)(1) is modified to specify the significant figures to use when evaluating an overstatement of GHG reductions and GHG removal enhancements.

Rationale for Section 95985(c)(1).

This change is needed to be consistent with the threshold for overstatement of GHG reductions and GHG removal enhancements as defined in the definition for "offset material misstatement." The use of 5.00 indicates that offset material misstatement should be evaluated to three significant figures.

Summary of Section 95985(c)(1)(A).

Existing section 95985(c)(1)(A) is modified to specify the significant figures to use when evaluating an overstatement of GHG reductions and GHG removal enhancements.

Rationale for Section 95985(c)(1)(A).

This change is needed to be consistent with the threshold for overstatement of GHG reductions and GHG removal enhancements as defined in the definition for "offset material misstatement." The use of 5.00 indicates that offset material misstatement should be evaluated to three significant figures.

Summary of Section 95985(e)(2).

Existing section 95985(e)(2) is modified to fix the spelling for the word "entities."

Rationale for Section 95985(e)(2).

This change is needed to fix the spelling error for the word "entities."

Summary of Section 95985(g)(1)(A)(2.).

Existing section 95985(g)(1)(A)(2.) is modified to remove the reference to serial numbers for ARB offset credits.

Rationale for Section 95985(g)(1)(A)(2.).

This change is also needed to remove the reference to serial numbers because ARB will not be publicly releasing serial numbers for ARB offset credits.

Summary of Section 95985(h).

Existing section 95985(h) is modified to change the application of this section to non-sequestration and urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments.

Rationale for Section 95985(h).

This change is needed to apply the provisions in section 95985(h) urban forestry offset projects and U.S. forestry offset projects issued on or after the effective date of these amendments.

Summary of Section 95985(h)(1).

Existing section 95985(h)(1) is modified to apply this section to ARB offset credits issued to urban forest projects and ARB offset credits issued to U.S. forest projects after the effective date of these amendments.

Rationale for Section 95985(h)(1).

This change is needed to align the liability rules for invalidation for all project types to buyer liability. Staff has chosen the effective date of these amendments to give the market time to plan for the shift in liability for U.S. forest projects. This will require that after the effective date of these amendments, the buyer, or retiree, must replace any invalidated offset credits for all project types. This provision is necessary to ensure that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Under the existing requirements, a 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, were not replaced by the offset project operator. Also, ARB has clear enforcement authority over covered entities that will be using ARB offsets for compliance.

Summary of Section 95985(h)(1)(C)(2.).

Existing section 95985(h)(1)(C)(2.) is modified to include a reference so that the OPO knows how many ARB offset credits they must replace.

Rationale for Section 95985(h)(1)(C)(2.).

This change is needed to clarify that the OPO would need to replace ARB offset credits that are invalidated if the buyer, or retiree, is no longer in business. This will ensure that ARB can make the program whole, even if the buyer, or retiree, is out of business. This was always the intent of this provision and this change makes the language more clear.

Summary of Section 95985(h)(1)(C)(3.).

Existing section 95985(h)(1)(C)(3.) is modified to include a reference so that the OPO knows how many ARB offset credits they must replace.

Rationale for Section 95985(h)(1)(C)(3.).

This change is needed to clarify that the OPO would need to replace ARB offset credits that are invalidated if the buyer, or retiree, is no longer in business. This will ensure that ARB can make the program whole, if the buyer, or retiree, is out of business. This was always the intent of this provision and this change makes the language more clear.

Summary of Section 95985(h)(1)(D).

Existing section 95985(h)(1)(D) is modified to remove the reference to serial numbers for ARB offset credits.

Rationale for Section 95985(h)(1)(D).

This change is needed to remove the reference to serial numbers because ARB will not be publicly releasing serial numbers for ARB offset credits.

Summary of Section 95985(h)(1)(E).

Existing section 95985(g)(1)(E) is modified to remove the reference to serial numbers for ARB offset credits.

Rationale for Section 95985(h)(1)(E).

This change is also needed to remove the reference to serial numbers because ARB will not be publicly releasing serial numbers for ARB offset credits.

Summary of Section 95985(h)(2).

Existing section 95985(h)(2) is modified to apply this section to ARB offset credits issued to urban forest projects and ARB offset credits issued to U.S. forest projects after the effective date of these amendments.

Rationale for Section 95985(h)(2).

This change is needed to align the liability rules for invalidation for all project types to buyer liability. Staff has chosen the effective date of these amendments to give the market time to plan for the shift in liability for U.S. forest projects. This will require that after the effective date of these amendments, the buyer, or retiree, must replace any invalidated offset credits for all project types. This provision is necessary to ensure that

purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Also, ARB has clear enforcement authority over covered entities that will be using ARB offsets for compliance.

Summary of Section 95985(h)(2)(B)(2.).

Existing section 95985(h)(2)(B)(2.) is modified to include a reference so that the OPO knows how many ARB offset credits they must replace.

Rationale for Section 95985(h)(2)(B)(2.).

This change is needed to clarify that the OPO would need to replace ARB offset credits that are invalidated if the buyer, or retiree, is no longer in business. This will ensure that ARB can make the program whole (preserve environmental integrity), even if the buyer, or retiree, is out of business. This was always the intent of this provision and this change makes the language more clear.

Summary of Section 95985(h)(2)(B)(3.).

Existing section 95985(h)(2)(B)(3.) is modified to include a reference so that the OPO knows how many ARB offset credits they must replace.

Rationale for Section 95985(h)(2)(B)(3.).

This change is needed to clarify that the OPO would need to replace ARB offset credits that are invalidated if the buyer, or retiree, is no longer in business. This will ensure that ARB can make the program whole (preserve environmental integrity), even if the buyer, or retiree, is out of business. This was always the intent of this provision and this change makes the language more clear.

Summary of Section 95985(i).

Existing section 95985(i) is modified to clarify that this section refers to U.S. forest projects and that the provisions in this section apply to ARB offset credits issued to U.S. forest projects prior to the effective date of these amendments .

Rationale for Section 95985(i).

This change is needed to clarify that this provision applies to U.S. forest projects and not urban forest projects. This change is also needed to clarify that this section applies to ARB offset credits issued to U.S. forest project prior to the effective date of these amendments. After the effective date of these amendments, the provisions in section 95985(h) apply to ARB offset credits issued to U.S. forest projects. This change is needed to align the liability rules for invalidation for all project types to buyer liability. This provision is necessary because under the current requirements, if a

covered entity retires a forestry ARB offset credit and then it gets invalidated, the forest landowner is responsible and the covered entity is still considered to be in compliance even if it does not have enough valid compliance instruments. By aligning the invalidation requirements for forestry with the existing invalidation requirements for other project types, entities are required to have enough valid compliance instruments to be considered in compliance with the regulation.

Summary of Section 95985(i)(1).

Existing section 95985(i)(1) is modified to clarify that this section refers to U.S. forest projects and that the provisions in this section apply to ARB offset credits issued to U.S. forest projects prior to the effective date of these amendments.

Rationale for Section 95985(i)(1).

This change is needed to clarify that this provision applies to U.S. forest projects and not urban forest projects. This change is also needed to clarify that this section applies to ARB offset credits issued to U.S. forest project prior to the effective date of these amendments. After the effective date of these amendments, the provisions in section 95985(h) apply to ARB offset credits issued to U.S. forest projects. This change is needed to align the liability rules for invalidation for all project types to buyer liability. Staff has chosen the effective date of these amendments to give the market time to plan for the shift in liability for U.S. forest projects. This will require that after the effective date of these amendments, the buyer, or retiree, must replace any invalidated offset credits for all project types. This provision is necessary to ensure that purchasers and users of offset credits do their due diligence in seeking out high-quality offset credits. Also, ARB has clear enforcement authority over covered entities that will be using ARB offsets for compliance.

Summary of Section 95985(i)(1)(A).

Existing section 95985(i)(1)(A) is modified to clarify that this section refers to U.S. forest projects.

Rationale for Section 95985(i)(1)(A).

This change is needed to clarify that this provision applies to U.S. forest projects and not urban forest projects.

Summary of Section 95985(i)(2).

Existing section 95985(i)(2) is modified to clarify that this section refers to U.S. forest projects.

Rationale for Section 95985(i)(2).

This change is needed to clarify that this provision applies to U.S. forest projects and not urban forest projects.

Section 95986. Executive Officer Approval Requirements for Offset Project Registries.

Summary of Section 95986(b).

Existing section 95986(b) is modified to clarify that an OPR must meet and maintain the requirements of this section.

Rationale for Section 95986(b).

This change is needed to clarify that once an OPR is approved, it must continue to meet the requirements upon which is was approved. This ensures that OPRs maintain the standards required by the Regulation over time.

Summary of Section 95986(c).

Existing section 95986(c) was removed from the Regulation.

Rationale for Section 95986(c).

This change is needed because OPRs may not be registered in CITSS.

Summary of Section 95986(d)(4).

Existing section 95986(d)(4) is modified to include a definition for the term "environmentally-focused market" to clarify the intent of this section.

Rationale for Section 95986(d)(4).

This change is needed to ensure that OPRs approved by ARB have demonstrated experience that will be needed to conduct registry services while operating as an OPR. This text also clarifies the experience of air districts that is relevant to demonstrating experience to apply as an OPR.

Summary of Section 95986(j).

Existing section 95986(j) is modified to clarify that the OPR must have at least two years of experience in areas related to registry services to be an approved OPR.

Rationale for Section 95986(j).

This change is needed to ensure that OPRs approved by ARB have demonstrated experience that will be needed to conduct registry services while operating as an OPR. The two years is consistent with the requirements in section 95986(d)(4).

Summary of Section 95986(l)(3).

Existing section 95986(l)(3) is modified to correct a spelling error.

Rationale for Section 95986(l)(3).

This change is needed to correct a spelling error for the word "extension."

Summary of Section 95986(m).

New section 95986(m) is added to clarify that the approval requirements in section 95986 apply to a designated subdivision of the OPR.

Rationale for Section 95986(m).

This section is needed to clarify that all OPR approval requirements are applied at the designated subdivision level, if the applicant designates a subdivision of the organization to be approved as an OPR.

Summary of Section 95986(n).

New section 95986(n) is added to require that an OPR make itself available to ARB audit.

Rationale for Section 95986(n).

This section is needed to ensure that ARB has access to relevant materials while on the site of an audit.

Section 95987. Offset Project Registry Requirements.

Summary of Section 95987(b)(2).

Existing section 95987(b)(2) is modified to clarify that an OPR must make registry issuance information publicly available within 10 working days.

Rationale for Section 95987(b)(2).

This change is needed to clarify when the OPR must make the information listed in section 95987(b)(2) publicly available. This change is needed because the information

listed in section 95987(b)(2) will not be available at the time the Offset Verification Statement is issued as indicated in the original text.

Summary of Section 95987(b)(2)(E).

New section 95987(b)(2)(E) is added to clarify that an OPR must make the final Offset Project Data Report publicly available.

Rationale for Section 95987(b)(2)(E).

This section is needed to require the OPR to make the final Offset Project Data Report publicly available. This will allow the basis for the registry offset credit issuance to be more transparent, as the public will be able to see the OPO's or APD's assertions.

Summary of Section 95987(b)(2)(F).

Existing section 95987(b)(2)(E) is renumbered to section 95987(b)(2)(F)

Rationale for Section 95987(b)(2)(F).

This change is needed to accommodate additional provisions in this section.

Summary of Section 95987(d).

Existing section 95987(d) is modified to require the OPR to consult with ARB before giving guidance on the compliance offset program.

Rationale for Section 95987(d).

This change is needed to ensure that the OPRs are giving consistent and approved guidance. ARB is the only party that may interpret the Regulation and make guidance on the compliance offset program publicly available.

Summary of Section 95987(e).

Existing section 95987(e) is modified to only allow full offset verifications to count towards the OPR audit requirements.

Rationale for Section 95987(e).

This section is needed to clarify that only audits of full offset verifications are allowed to count towards the 10 percent annual audit requirements for OPRs. This clarification is needed so that OPRs do not use desk review audits or interim verifications towards meeting the 10 percent audit requirements.

Subarticle 14: Recognition of Compliance Instruments from Other Programs

Section 95990. Recognition of Early Action Offset Credits.

Summary of Section 95990(c)(3).

Existing section 95990(c)(3) is modified to move requirements from 95990(c)(3) to 95990(c)(3)(A) to add additional early action quantification methodologies for mine methane capture projects.

Rationale for Section 95990(c)(3).

This change is needed to include new potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(c)(3)(A).

New section 95990(c)(3)(A) is added to require that livestock, ODS, U.S. forestry, and urban forestry early action offset projects list with an EAOP by January 1, 2014.

Rationale for Section 95990(c)(3)(A).

This section is added to move the requirements that livestock, ODS, U.S. forestry, and urban forestry early action offset projects must list with an EAOP by January 1, 2014, from existing section 95990(c)(3) to this new section. These are not new requirements; however, they were moved to new section 95990(c)(3)(A) to accommodate additional requirements for potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(c)(3)(B).

New section 95990(c)(3)(B) is added to include listing requirements for potential early action quantification methodologies for mine methane capture projects which staff is proposing for Board adoption.

Rationale for Section 95990(c)(3)(B).

This section is added to allow mine methane capture early action offset projects to have a later listing date than the other project types for early action, since the protocol was added to the program must later than the others.

Summary of Section 95990(c)(5)(C).

Existing section 95990(c)(5)(C) is modified to accommodate additional provisions in this section for new potential early action quantification methodologies for mine methane capture projects.

Rationale for Section 95990(c)(5)(C).

This change is needed to accommodate additional provisions in this section for new potential early action quantification methodologies for mine methane capture projects.

Summary of Section 95990(c)(5)(D).

Existing section 95990(c)(5)(D) is modified to accommodate additional provisions in this section for new potential early action quantification methodologies for mine methane capture projects.

Rationale for Section 95990(c)(5)(D).

This change is needed to accommodate additional provisions in this section for new potential early action quantification methodologies for mine methane capture projects.

Summary of Section 95990(c)(5)(E).

New section 95990(c)(5)(D) is added to include the Verified Carbon Standard Revisions to ACM0008 to Include Pre-drainage of Methane from an Active Open Cast Mine as a Methane Emission Reduction Activity Methodology, v1.0 and Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology, v1.0 on the list of approved early action quantification methodologies. These methodologies have not yet been approved as staff is proposing them to the Board for adoption.

Rationale for Section 95990(c)(5)(E).

This change is needed to include the potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(d)(2)(B).

Existing section 95990(d)(2)(B) is modified to include requirements for parties that must register with ARB for potential mine methane capture early action offset projects.

Rationale for Section 95990(d)(2)(B).

This change is needed to include requirements that OPOs, APDs, and holders must meet if they are listing an early action offset project under the potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(e).

Existing section 95990(e) is modified to require that an OPO, APD, or holder(s) list an early action offset project before ARB reviews the conflicts of interest and verification information for the offset project.

Rationale for Section 95990(e).

This change is needed to require that an early action offset project is listed with ARB, before ARB will review any information related to conflicts of interest or desk reviews. This is needed so ARB has basic information related to the offset project before it reviews any other documentation. In addition, an OPO, APD, or holder(s) must list the project to signal to ARB that the offset project is coming into the compliance offset program before ARB will review any other documentation related to the transition of early action offset credits to ARB offset credits.

Summary of Section 95990(e)(1)(B)(2.).

Existing section 95990(e)(1)(B)(2.) is modified to include a reference to mine methane capture projects for which staff is proposing an early action quantification methodologies to the Board for adoption.

Rationale for Section 95990(e)(1)(B)(2.).

This change is needed to require that OPOs, APDs, and holders must submit the information in this section if they are listing an early action offset project under the potential early action quantification methodologies for mine methane capture projects which staff is proposing for Board adoption.

Summary of Section 95990(e)(1)(C).

Existing section 95990(e)(1)(C) is modified to accommodate additional provisions in this section.

Rationale for Section 95990(e)(1)(C).

This change is needed to accommodate new requirements added in new section (e)(1)(C)(2.).

Summary of Section 95990(e)(1)(C)(1.).

New section 95990(e)(1)(C)(1.) is added to accommodate additional provisions in this section and contains text previously in section 95990(e)(1)(C).

Rationale for Section 95990(e)(1)(C)(1.).

This change is needed to accommodate new requirements added in new section (e)(1)(C)(2.). The original text has not changed.

Summary of Section 95990(e)(1)(C)(2.).

New section 95990(e)(1)(C)(2.) is added to require holders to contact the OPO or APD of the project to be eligible to list the early action offset project.

Rationale for Section 95990(e)(1)(C)(2.).

This section is needed to clarify that if holder(s) do not get written permission from the OPO or APD to list the early action project, the holder(s) must show proof of the request to list the offset project to ARB and allow the OPO or APD 30 days to list the offset project themselves. This is intended to allow the holder(s) to list as long as they work with the OPO or APD up front. If the OPO or APD will not list the offset project themselves within a timely manner, ARB will allow the holder(s) to list the project on its own.

Summary of Section 95990(e)(2)(F).

Existing section 95990(e)(2)(F) is modified to require the OPO, APD, or holder(s) to identify the verification body's association with the project under the EAOP in the listing information.

Rationale for Section 95990(e)(2)(F).

This change is needed to clarify that the OPO, APD, or holder(s) must provide the information related to the verification bodies that conducted verification work under the EAOP. This is a necessary distinction because early action offset projects may have participated in voluntary programs other than the EAOP.

Summary of Section 95990(e)(2)(G).

New section 95990(e)(2)(G) is added to clarify that for ODS destruction early action offset projects each destruction event may be considered an individual project.

Rationale for Section 95990(e)(2)(G).

This section is needed to clarify that each reporting period for an ODS destruction early action offset project may be considered an individual project when an OPO, APD, or holder lists the early action offset project. This is consistent with the requirements for ODS destruction projects developed under the COP.

Summary of Section 95990(e)(3).

New section 95990(e)(3) is added to clarify that multiple Reporting Periods may be submitted simultaneously, but it is not required to include all Reporting Periods when listing early action offset projects.

Rationale for Section 95990(e)(3).

This section is needed to clarify that an OPO, APD, or holder(s) does not have to list all Reporting Periods for an early action offset project. OPOs or APDs may decide to leave some Reporting Periods in the voluntary market because of pre-existing contractual arrangements, or other reasons.

Summary of Section 95990(e)(4).

Existing section 95990(e)(3) is renumbered to new section 95990(e)(4). This section is modified to use the new term "early action reporting period," defined in section 95802.

Rationale for Section 95990(e)(4).

This change is needed to accommodate new requirements in this section. This change is also needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(f)(1).

Existing section 95990(f)(1) is modified to require that the offset verification team include a project specific verifier on the verification team for desk reviews of early action offset projects.

Rationale for Section 95990(f)(1).

This section is needed to require that an offset project specific verifier reviews the offset project information during a desk review. This will ensure that the offset project information is reviewed by an ARB-accredited verifier that has specific expertise in the applicable offset project type.

Summary of Section 95990(f)(3).

Existing section 95990(f)(3) is modified to use the new term "early action reporting period," defined in section 95802. This section is also modified to include a reference to new provisions added to section 95990(f), which allows OPOs, APDs, or holders to opt out of the desk review under certain circumstances. This section is also modified to specify that an early action desk review can only be conducted once for each reporting period.

Rationale for Section 95990(f)(3).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP. This change is also needed to reference additional requirements that were added to section 95990(f)(3). These requirements allow an OPO, APD, or holder to opt out of the desk review and go straight to a full verification of the early action offset project information if they cannot get access to the relevant information. This change is also needed to clarify that ARB will only accept one desk review finding for each reporting period. If multiple holders list the offset project, ARB will only accept the first desk review findings submitted. This desk review finding will determine whether the reporting period meets the requirements of the Regulation.

Summary of Section 95990(f)(3)(B).

Existing section 95990(f)(3)(B) is modified to require that the desk review verification body recalculate the data checks conducted by the original EAOP verification body.

Rationale for Section 95990(f)(3)(B).

This change is needed to clarify that the desk review verification team must recalculate the data checks that the original verification body calculated and ensure they were calculated correctly during the initial verification done under the EAOP. This is not a change to the Regulation, but a clarification. This is needed to ensure that the original verification body did their due diligence in the original verification and that the original verification body did not make any errors.

Summary of Section 95990(f)(3)(C).

Existing section 95990(f)(3)(C) is modified to use the new term "early action reporting period," defined in section 95802. This change is also needed to require that the verification body submit a report to ARB detailing the findings of the early action desk review and to require the OPO, APD, or holder(s) to submit the early action reporting periods for listing before ARB will review the verification related information.

Rationale for Section 95990(f)(3)(C).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP. This change is also needed to require the desk review verification body to submit a report to ARB detailing how it came to its conclusion to submit a positive desk review finding. This will help ARB in reviewing the desk review verification body's work during the desk review verification. This change is also needed to require an early action reporting period to be listed prior to the desk review findings being submitted. This will help ARB in tracking project documents by having a listing created before any other documents are received.

Summary of Section 95990(f)(3)(D).

Existing section 95990(f)(3)(D) is modified to use the new term "early action reporting period," defined in section 95802.

Rationale for Section 95990(f)(3)(D).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(f)(3)(E).

Existing section 95990(f)(3)(E) is modified to use a new term defined in section 95802.

Rationale for Section 95990(f)(3)(E).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(f)(3)(F).

New section 95990(f)(3)(F) is added to include a process for ARB review of the desk review findings submitted by the verification body. If ARB does not agree with a positive finding submitted by the verification body, ARB will deny the findings and require a full verification be conducted. ARB will seek additional information from the desk review verification body and the party that listed the early action offset project, if needed, before making its determination.

Rationale for Section 95990(f)(3)(F).

This section is needed to provide a process for ARB to review the desk review findings submitted by the desk review verification body. This process will allow ARB to make the final decision as to whether the initial verification and the desk review meets the requirements of the Regulation, since ARB is the issuer of ARB offset credits.

Summary of Section 95990(f)(3)(G).

New section 95990(f)(3)(G) is added to include a process so the OPO, APD, or holder(s) may opt out of the desk review under certain circumstances.

Rationale for Section 95990(f)(3)(G).

This section is needed to allow OPOs, APDs, and holders to opt out of the desk review if the desk review verification body is unable to obtain the required information for the desk review from the original verification body. This will save the OPOs', APDs', and holders' time and costs associated with a desk review if they cannot obtain the information needed to conduct the desk review.

Summary of Section 95990(f)(4).

Existing section 95990(f)(4) is modified to use the new term "early action reporting period," defined in section 95802.

Rationale for Section 95990(f)(4).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(f)(6).

Existing section 95990(f)(6) is modified to correct terminology and references used in this section. This section is also modified to clarify that the OPO, APD or holder does not have to move forward with full offset verification, but the project would be ineligible for crediting.

Rationale for Section 95990(f)(6).

This change is needed to correct references and terminology in this section and make them consistent throughout the Regulation. This change is also needed to clarify that a full verification of an early action offset project is based on the original reporting information submitted to the EAOP. In a full verification an ARB-accredited verification body is no longer checking the work of another verification body, it is conducting its own

independent offset verification services. The full verification is based on the early action quantification methodology under which the OPO or APD reported to the EAOP. This change is also needed to clarify that a full verification is not required and the OPO, APD, or holder(s) may opt out of the compliance offset program and keep the early action offset credits in the voluntary market. However, if the desk review or information for the desk review is insufficient a full offset verification must be conducted to transition the early action offset credits into ARB offset credits.

Summary of Section 95990(f)(6)(E).

Existing section 95990(f)(6)(E) is modified to use the new term "early action reporting period," defined in section 95802.

Rationale for Section 95990(f)(6)(E).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(f)(7).

Existing section 95990(f)(7) is modified to use the new term "early action reporting period," defined in section 95802.

Rationale for Section 95990(f)(7).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(g).

Existing section 95990(g) is modified to use the new term "early action reporting period," defined in section 95802. This section is also modified to clarify that conflict of interest self-evaluations for multiple early action reporting periods may be submitted together for an early action offset project. This section is also modified to require that the early action offset project listing be approved by ARB prior to submittal of a conflict of interest self-evaluation for the early action offset project.

Rationale for Section 95990(g).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP. This change is also needed to clarify that a conflict of interest self-

evaluation for an early action offset project may be submitted for multiple early action reporting periods. This clarifies that a verification body does not need to submit one self-evaluation for each early action reporting period associated with one early action offset project. This change is also needed clarify that the OPO, APD, or holder(s) must have the listing for the corresponding early action reporting periods for the early action offset project approved before the verification body may submit the self-evaluation. This gives ARB adequate time to process the listing information and allows ARB to collect basic information about the offset project before ARB must review other project documentation.

Summary of Section 95990(g)(2)(A).

Existing section 95990(g)(2)(A) is modified to clarify that the conflict of interest requirements must be assessed against the OPO, APD and any holder(s) that are transitioning early action offset credits to ARB offset credits.

Rationale for Section 95990(g)(2)(A).

This change is needed to clarify that if there is an APD, the verification body must assess conflict of interest against the APD. This change is also needed to clarify that if a holder has contracted with the verification body to conduct verification for an early action offset project, the verification body must assess conflict of interest against that holder. This is needed to ensure that there are no prior relationships that may cause a potential conflict of interest between the APD or holder, if applicable, and the verification body, its staff, and any subcontractors on the team.

Summary of Section 95990(g)(2)(B).

Existing section 95990(g(2)(B) is modified to use the new term "early action reporting period," defined in section 95802.

Rationale for Section 95990(g)(2)(B).

This change is needed to include the new term "early action reporting period" to distinguish between Reporting Periods under a COP and reporting periods as defined by the EAOP.

Summary of Section 95990(h)(3).

Existing section 95990(h)(3) is modified to clarify that the verification under the EAOP must be completed by September 30, 2015 to be eligible for issuance of ARB offset credits in lieu of early action offset credits.

Rationale for Section 95990(h)(3).

This change is needed to ensure that the verification body conducting verification services under the EAOP has completed its services by September 30, 2015. This gives the original verification body enough time to verify any GHG reductions or GHG removal enhancements that were achieved through 2014.

Summary of Section 95990(h)(5)(B)(2.).

Existing section 95990(h)(5)(B)(2.) is modified to require OPOs, APDs, or holders to submit attestations for issuance of ARB offset credits for potential mine methane capture early action offset projects.

Rationale for Section 95990(h)(5)(B)(2.).

This change is needed to require that OPOs, APDs, and holders submit attestations to ARB for issuance of ARB offset credits, if they are seeking issuance of early action offset credits for GHG reductions achieved under the potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(h)(6)(A).

Existing section 95990(h)(6)(A) is modified to fix punctuation in the attestation language.

Rationale for Section 95990(h)(6)(A).

This change is needed to ensure correct punctuation is used in this provision.

Summary of Section 95990(h)(6)(B).

Existing section 95990(h)(6)(B) is modified to fix punctuation in the attestation language.

Rationale for Section 95990(h)(6)(B).

This change is needed to ensure correct punctuation is used in this provision.

Summary of Section 95990(i)(1)(D)(1.).

Existing section 95990(i)(1)(D)(1.) is modified to require that ARB notifies the EAOP of how many early action offset credits must be retired from its buffer account for ARB offset credits to be issued to an early action offset project.

Rationale for Section 95990(i)(1)(D)(1.).

This change is needed to clarify that ARB will notify the EAOP of how many ARB offset credits must be retired for purposes of ARB offset credit issuance and subsequent placement in the Forest Buffer Account (FBA). This process provides for the removal and retirement of early action offset credits in an EAOP's buffer account for reissuance as ARB offset credits and placement in ARB's FBA.

Summary of Section 95990(i)(1)(D)(1.)(a.).

Existing text in section 95990(i)(1)(D)(1.)(a.) is deleted and replaced by new text that requires early action offset credits to meet the requirements in section 95990 to qualify for placement in the FBA.

Rationale for Section 95990(i)(1)(D)(1.)(a.).

This section is needed to clarify that only early action offset credits that meet the requirements of section 95990 may be used to meet ARB's Forest Buffer Account requirements. Staff has removed the requirement that early action offset credits issued from 2001-2004 be placed into the FBA because these offset credits do not meet the requirements of section 95990.

Summary of Section 95990(i)(1)(D)(1.)(b.).

Existing text in section 95990(i)(1)(D)(1.)(b.) is deleted and replaced by new text which explains that if ARB offset credits were placed in the Forest Buffer Account in excess of what is required by these revisions, the ARB offset credits will be canceled so that they may be returned to the EAOP.

Rationale for Section 95990(i)(1)(D)(1.)(b.).

This section is needed to allow ARB to transfer offset credits back to the EAOP if those offset credits do not meet the requirements of section 95990, or ARB took more early action offset credits from the EAOP than was required. The original text in this section required the EAOP to transfer its entire buffer account contributions for an early action offset project to ARB, even if the offset credits did not meet the requirements of this section, or ARB did not need the entire amount of the buffer account contribution for that offset project. To ensure that ARB does not have to cover any losses from a reversal in the EAOP, ARB is refunding these credits back to the EAOP, so that the EAOP can manage these offset credits in its own buffer account.

Summary of Section 95990(i)(1)(D)(1.)(b.)(i.).

New section 95990(i)(1)(D)(1.)(b.)(i.) is added to specify that ARB will transfer offset credits back to the EAOP if they do not meet the requirements of section 95990.

Rationale for Section 95990(i)(1)(D)(1.)(b.)(i.).

This section is needed to refund the 2001-2004 vintage offset credits that ARB receives from the EAOP. These offset credits do not meet the requirements of the Regulation and, therefore, may not be used in the FBA.

Summary of Section 95990(i)(1)(D)(1.)(b.)(ii.).

New section 95990(i)(1)(D)(1.)(b.)(ii.) is added to specify that early action offset credits taken from the EAOP's buffer account in excess of the number required by these revisions will be returned to the EAOP.

Rationale for Section 95990(i)(1)(D)(1.)(b.)(ii.).

This section is needed to refund early action offset credits to the EAOP in the cases where ARB required the EAOP to transfer more buffer pool credits than needed to cover the ARB offset credits issued for that offset project.

Summary of Section 95990(i)(1)(D)(2.).

Existing section 95990(i)(1)(D)(2.) is modified to include a calculation that quantifies how many ARB offset credits must be contributed to ARB's FBA.

Rationale for Section 95990(i)(1)(D)(2.).

This section is needed to clarify the number of ARB offset credits that ARB will require to be placed in the FBA when early action offset credits are transitioned to ARB offset credits for forest offset projects. This will make the ARB process for determining this amount more transparent to participants in the program.

Summary of Section 95990(i)(1)(D)(2.)(a.).

New section 95990(i)(1)(D)(2.)(a.) is added to clarify that ARB will calculate the FBA contribution for an early action reporting period by using the requirements in the COP for U.S. forest projects.

Rationale for Section 95990(i)(1)(D)(2.)(a.).

This section is needed to clarify that ARB will use the reversal risk rating in the U.S. Forest Projects COP to calculate the number of ARB offset credits that must be placed

into ARB's FBA. This is needed to ensure that ARB's FBA has adequate supply in the case of an unintentional reversal, and to ensure that all forest offset projects in the compliance offset program contribute an appropriate and proportionate amount of ARB offset credits to the FBA.

Summary of Section 95990(i)(1)(D)(2.)(b.).

New section 95990(i)(1)(D)(2.)(b.) is added to clarify which values of risk that ARB will use to calculate the reversal risk rating for the FBA contribution.

Rationale for Section 95990(i)(1)(D)(2.)(b.).

This section is needed to clarify that ARB will use the maximum value for each risk category that is calculated in the reversal risk rating in the COP, unless during the original verification, the verification body reviewed the risk category and made a determination for that category that would lower the risk rating for that category. This will ensure that the reversal risk rating is applied consistently between early action offset projects and compliance offset projects.

Summary of Section 95990(i)(1)(D)(2.)(c.).

New section 95990(i)(1)(D)(2.)(c.) is added to clarify that qualified conservation easements may not apply retroactively to early action offset projects to reduce the reversal risk rating.

Rationale for Section 95990(i)(1)(D)(2.)(c.).

This section is needed to clarify that a qualified conservation easement entered into after the original verification of the GHG reductions and GHG removal enhancements may not be applied to reduce the reversal risk rating retroactively. This is needed because a qualified conservation easement cannot be retroactively applied because it does not exist in the early action quantification methodologies approved for forest early action offset projects. This is also needed to allow the qualified conservation easement to be used to reduce the reversal risk rating once the offset project transitions to the COP.

Summary of Section 95990(i)(1)(D)(3.).

Existing section 95990(i)(1)(D)(3.) is modified to clarify how many ARB offset credits will be issued to the OPO, APD, or holder(s) for forest early action offset projects after the FBA contribution is calculated.

Rationale for Section 95990(i)(1)(D)(3.).

This change is needed to clarify how many ARB offset credits will be issued to the OPO, APD, or holder(s) once ARB has calculated the FBA contribution required for the early action reporting period. This section provides a transparent calculation for how ARB will determine the issuance amount to forest offset projects.

Summary of Section 95990(i)(1)(D)(3.)(a.).

Existing section 95990(i)(1)(D)(3.)(a.) is modified to include a calculation to quantify how many ARB offset credits will be issued to the OPO, APD, or holder(s) for a forest early action offset project once ARB has calculated the FBA contribution required for the early action reporting period. The equation is applied if no early action offset credits have been retired from the EAOP's buffer account, and the risk rating in the COP is less than or equal to the risk rating calculated by the EAOP.

Rationale for Section 95990(i)(1)(D)(3.)(a.).

This change is needed to clarify how many ARB offset credits will be issued to the OPO, APD, or holder(s) if no early action offset credits have been retired from the EAOP's buffer account, and the risk rating in the COP is less than or equal to the risk rating calculated by the EAOP. If these criteria are met then ARB will issue one ARB offset credit for each early action offset credit being transitioned. In this case the contribution being transferred from the EAOP's buffer account is sufficient to cover the amount needed to meet the FBA contribution requirements in the Regulation, and no additional ARB offset credits must be deducted from the OPO, APD, or holder(s) issuance request.

Summary of Section 95990(i)(1)(D)(3.)(a.)(i.).

New section 95990(i)(1)(D)(3.)(a.)(i.) is added to include a calculation to quantify how many early action offset credits the EAOP must retire from its buffer account.

Rationale for Section 95990(i)(1)(D)(3.)(a.)(i.).

This section is needed to clarify how many early action offset credits must be retired by the EAOP once ARB calculates the required FBA contribution. This amount depends on the number of ARB offset credits that the OPO, APD, or holder(s) is seeking issuance of.

Summary of Section 95990(i)(1)(D)(3.)(a.)(ii.).

New section 95990(i)(1)(D)(3.)(a.)(ii.) is added to include a calculation to quantify how many ARB offset credits the OPO, APD, or holder(s) will receive in a Holding Account after ARB has calculated the FBA contribution.

Rationale for Section 95990(i)(1)(D)(3.)(a.)(ii.).

This section is needed to clarify how many ARB offset credits ARB will issue into the OPO's, APD's, or holder'(s) Holding Account once ARB calculates the required FBA contribution. This provides the OPO, APD, and holder(s) transparency by providing the process that ARB uses to determination how many ARB offset credits the OPO, APD, and holder(s) will receive.

Summary of Section 95990(i)(1)(D)(3.)(b.).

Existing section 95990(i)(1)(D)(3.)(b.) is modified to include a calculation to quantify how many ARB offset credits will be issued to the OPO, APD, or holder(s) for a forest early action offset project once ARB has calculated the FBA contribution required for the early action reporting period. The equation is applied if no early action offset credits have been retired from the EAOP's buffer account, and the risk rating in the COP is greater than the risk rating calculated by the EAOP.

Rationale for Section 95990(i)(1)(D)(3.)(b.).

This change is needed to clarify how many ARB offset credits will be issued to the OPO, APD, or holder(s) if no early action offset credits have been retired from the EAOP's buffer account, and the risk rating in the COP is greater than the risk rating calculated by the EAOP. If these criteria are met then ARB will issue ARB offset credits in the amount calculated pursuant to the equation in this section. In this case the contribution being transferred from the EAOP's buffer account is insufficient to cover the amount needed to meet the FBA contribution requirements in the Regulation and ARB must deduct ARB offset credits from the amount issued to the OPO, APD, or holder(s), in an amount to cover the difference.

Summary of Section 95990(i)(1)(D)(3.)(b.)(i.).

New section 95990(i)(1)(D)(3.)(b.)(i.) is added to include a calculation to quantify how many early action offset credits the EAOP must retire from its buffer account.

Rationale for Section 95990(i)(1)(D)(3.)(b.)(i.).

This section is needed to clarify how many early action offset credits must be retired by the EAOP once ARB calculates the required FBA contribution. This amount depends

on the number of ARB offset credits for which the OPO, APD, or holder(s) is seeking issuance.

Summary of Section 95990(i)(1)(D)(3.)(b.)(ii.).

New section 95990(i)(1)(D)(3.)(b.)(ii.) is added to include a calculation to quantify how many ARB offset credits the OPO, APD, or holder(s) will receive in a Holding Account after ARB has calculated the FBA contribution.

Rationale for Section 95990(i)(1)(D)(3.)(b.)(ii.).

This section is needed to clarify how many ARB offset credits ARB will issue into the OPO, APD, or holder(s) Holding Account once ARB calculates the required FBA contribution. This provides the OPO, APD, and holder(s) transparency by providing the process that ARB uses to determination how many ARB offset credits the OPO, APD, and holder(s) will receive.

Summary of Section 95990(i)(1)(D)(3.)(c.).

New section 95990(i)(1)(D)(3.)(c.) is added to include a calculation to quantify how many ARB offset credits will be issued to the OPO, APD, or holder(s) for a forest early action offset project once ARB has calculated the FBA contribution required for the early action reporting period. The equation is applied if early action offset credits have been retired from the EAOP's buffer account. This calculation is applied regardless of whether the reversal risk rating is equivalent under the EAOP and the COP.

Rationale for Section 95990(i)(1)(D)(3.)(c.).

This section is needed to clarify how many ARB offset credits will be issued to the OPO, APD, or holder(s) if early action offset credits have been retired from the EAOP's buffer account for reversals. If early action offset credits have been retired from the EAOP's buffer account then ARB will issue ARB offset credits in the amount calculated pursuant to the equation in this section. In this case the contribution being transferred from the EAOP's buffer account is insufficient to cover the amount needed to meet the FBA contribution requirements and ARB must deduct ARB offset credits from the amount issued to the OPO, APD, or holder(s), in an amount to cover the difference.

Summary of Section 95990(i)(1)(D)(3.)(c.)(i.).

New section 95990(i)(1)(D)(3.)(c.)(i.) is added to include a calculation to quantify how many early action offset credits the EAOP must retire from its buffer account.

Rationale for Section 95990(i)(1)(D)(3.)(c.)(i.).

This section is needed to clarify how many early action offset credits must be retired by the EAOP once ARB calculates the required FBA contribution. This amount depends on the number of ARB offset credits for which the OPO, APD, or holder(s) is seeking issuance.

Summary of Section 95990(i)(1)(D)(3.)(c.)(ii.).

New section 95990(i)(1)(D)(3.)(c.)(ii.) is added to include a calculation to quantify how many total ARB offset credits will be issued for the early action reporting period once ARB has calculated the required FBA contribution.

Rationale for Section 95990(i)(1)(D)(3.)(c.)(ii.).

This section is added to clarify how many total ARB offset credits ARB will issue for an early action reporting period if early action offset credits have been retired from the EAOP's buffer account. The total amount includes ARB offset credits that will be placed into the OPO's, APD's, or holder(s) Holding Account, and ARB offset credits that will be placed into the FBA account to account for the early action offset credits that cannot be transferred because they have already been retired.

Summary of Section 95990(i)(1)(D)(3.)(c.)(iii.).

New section 95990(i)(1)(D)(3.)(c.)(iii.) is added to include a calculation to quantify how many ARB offset credits the OPO, APD, or holder(s) will receive in a Holding Account after ARB has calculated the FBA contribution.

Rationale for Section 95990(i)(1)(D)(3.)(c.)(iii.).

This section is needed to clarify how many ARB offset credits ARB will issue into the OPO, APD, or holder(s) Holding Account once ARB calculates the required FBA contribution. This provides the OPO, APD, and holder(s) transparency by providing the process that ARB uses to determination how many ARB offset credits the OPO, APD, and holder(s) will receive.

Summary of Section 95990(i)(1)(D)(3.)(d.).

New section 95990(i)(1)(D)(3.)(d.) is added to require that EAOPs show proof of early action offset credit retirement upon ARB's request.

Rationale for Section 95990(i)(1)(D)(3.)(d.).

This section is needed to require that an EAOP provide proof to ARB that early action offset credits are retired prior to ARB's issuance of ARB offset credits for the same GHG

reductions and GHG removal enhancements. This ensures that offset credits are not issued for the same GHG reductions or GHG removal enhancements in both programs.

Summary of Section 95990(i)(1)(D)(4.).

Existing section 95990(i)(1)(D)(4.) is deleted. Existing section 95990(i)(1)(D)(5.) is renumbered to new section 95990(i)(1)(D)(4.). No changes were made to the text in this section.

Rationale for Section 95990(i)(1)(D)(4.).

This change is needed because existing section 95990(i)(1)(D)(4.) was deleted, which caused a renumbering of this section.

Summary of Section 95990(i)(1)(D)(5.).

Existing section 95990(i)(1)(D)(6.) is renumbered to new section 95990(i)(1)(D)(5.).

Rationale for Section 95990(i)(1)(D)(5.).

This change is needed because existing section 95990(i)(1)(D)(4.) was deleted, which caused a renumbering of this section.

Summary of Section 95990(i)(1)(E).

New section 95990(i)(1)(E) is added to include requirements for how many ARB offset credits will be issued for potential mine methane capture early action offset projects.

Rationale for Section 95990(i)(1)(E).

This change is needed to include requirements that specify how many early action offset credits will be issued for potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(i)(1)(F).

New section 95990(i)(1)(E) is added to include requirements for how many ARB offset credits will be issued for early action offset credits generated under the Verified Carbon Standard Revisions to ACM0008 to Include Pre-drainage of Methane from an Active Open Cast Mine as a Methane Emission Reduction Activity Methodology, v1.0 and Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology, v1.0 .

Rationale for Section 95990(i)(1)(F).

This change is needed to include requirements that specify how many early action offset credits will be issued for potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption.

Summary of Section 95990(i)(1)(F)(1).

New section 95990(i)(1)(E)(1) is added to specify that one ARB offset credit will be issued for each early action offset credit if the early action reporting period does not take credit for avoided emissions from the use of the captured mine methane

Rationale for Section 95990(i)(1)(F)(1).

This change is needed to include requirements that specify how many early action offset credits will be issued for potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption. It is appropriate to credit on a one to one basis if avoided emissions are not account for in the reporting period.

Summary of Section 95990(i)(1)(F)(2).

New section 95990(i)(1)(E)(2) is added to specify that no ARB offset credits will be issued for early action reporting periods that take credit for avoided emissions from the use of the captured mine methane

Rationale for Section 95990(i)(1)(F)(2).

This change is needed to include requirements that specify how many early action offset credits will be issued for potential early action quantification methodologies for mine methane capture projects, which staff is proposing for Board adoption. It is appropriate to not credit the reporting periods that take credit for avoided emissions because it is policy not to credit avoided emissions from covered sectors such as electricity and fuel because they would be covered in California and ineligible for offset credits .

Summary of Section 95990(i)(1)(F)(2)(a).

Existing section 95990(i)(1)(F)(2.)(a.) is modified to correct a section reference. This section is also modified to clarify that if ARB offset credits are issued under section 95990(i)(1)(F)(1.), the ARB offset credits will issued to the OPO or APD.

Rationale for Section 95990(i)(1)(F)(2)(a).

This change is needed because new section 95990(i)(1)(E) was added, which caused references to other provisions in this section to change. This change is also needed to clarify that if any additional ARB offset credits are issued under section 95990(i)(1)(F)(1.), the ARB offset credits will issued to the OPO or APD, and not holders.

Summary of Section 95990(i)(1)(F)(2)(b).

Existing section 95990(i)(1)(F)(2.)(b.) is modified to correct a section reference.

Rationale for Section 95990(i)(1)(F)(2)(b).

This change is needed because new section 95990(i)(1)(E) was added, which caused references to other provisions in this section to change.

Summary of Section 95990(i)(1)(F)(3).

New section 95990(i)(1)(F)(3.) is added to clarify that this section does not apply to holders.

Rationale for Section 95990(i)(1)(F)(3).

This section is needed to clarify that this section does not apply to holders of early action offset credits, because the additional sequestration calculated is applied at the offset project level, and the OPO or APD is the only party that may have claims to those ARB offset credits, as they are not owned by any holders.

Summary of Section 95990(i)(1)(G).

Existing section 95990(i)(1)(E) is renumbered to new section 95990(i)(1)(F).

Rationale for Section 95990(i)(1)(G).

This change is needed because new section 95990(i)(1)(E) was added, which caused a renumbering of this section.

Summary of Section 95990(i)(3).

Existing section 95990(i)(3) is modified to include consistent terminology throughout this section.

Rationale for Section 95990(i)(3).

This change is needed to ensure that consistent terminology is used throughout this section for permanently retiring or canceling early action offset credits.

Summary of Section 95990(i)(4).

Existing section 95990(i)(4) is modified to include consistent terminology throughout this section.

Rationale for Section 95990(i)(4).

This change is needed to ensure that consistent terminology is used throughout this section for the parties that are transitioning early action offset credits to ARB offset credits.

Summary of Section 95990(j)(1).

Existing section 95990(j)(1) is modified to apply ARB offset credit transfer rules to ARB offset credits issued for additional sequestration credited pursuant to section 95990(i)(1)(F).

Rationale for Section 95990(j)(1).

This change is needed to make a distinction between transferring ARB offset credits issued pursuant to sections 95990(i)(1)(A) through (E), and ARB offset credits issued pursuant to section 95990(i)(1)(F) for additional sequestration from transitioning the baseline for early action forest projects using version 2.1. The requirements for transferring ARB offset credits issued for additional sequestration crediting to Holding Accounts are described in this section and these requirements may only be applied to OPOs and APDs, and not holders.

Summary of Section 95990(j)(2).

Existing section 95990(j)(2) is modified to apply the ARB offset credit transfer rules to ARB offset credits issued according to sections 95990(i)(1)(A) through (E).

Rationale for Section 95990(j)(2).

This change is needed to make a distinction between ARB offset credits issued pursuant to sections 95990(i)(1)(A) through (E), and ARB offset credits issued pursuant to section 95990(i)(1)(F) for additional sequestration from transitioning the baseline for early action forest projects using version 2.1. The requirements for transferring ARB offset credits to Holding Accounts for sections 95990(i)(1)(A) through (E) are described in this section and these requirements may be applied to OPOs, APDs, and holder(s).

The requirements for transferring ARB offset credits issued for additional sequestration from transitioning the baseline for early action forest projects using version 2.1 to Holding Accounts are described in section 95990(j)(1) and the requirements may only be applied to OPOs and APDs, and not holders.

Summary of Section 95990(j)(2)(A).

New section 95990(j)(2)(A) is added to require that OPOs, APDs, and holder(s) must submit an issuance request for ARB offset credits to be transferred into a Holding Account.

Rationale for Section 95990(j)(2)(A).

This section is needed to clarify the requirements that OPOs, APDs, and holder(s) must meet when requesting issuance of ARB offset credits. This section is needed to ensure that the OPO and APD submit the correct information to ARB for the issuance of ARB offset credits. This change is also needed to ensure that the OPOs, APDs, and holder(s) requesting issuance of ARB offset credits actually own early action offset credits from the early action reporting period for which they are seeking issuance of ARB offset credits.

Summary of Section 95990(j)(2)(B).

New section 95990(j)(2)(B) is added to require parties receiving ARB offset credits to be registered with ARB.

Rationale for Section 95990(j)(2)(B).

This section is needed because a party must be registered with ARB and have an account in CITSS before it may receive any ARB offset credits into a Holding Account.

Summary of Section 95990(j)(2)(C).

New section 95990(j)(2)(C) is added to require ARB to make information related to early action offset credit eligibility publicly available.

Rationale for Section 95990(j)(2)(C).

This section is needed to give program participants information related to the eligibility of early action offset credits for the compliance offset program. Once ARB makes information related to the eligibility of early action offset credits publicly available on its website, market participants will know whether offset credits they hold may also be eligible to be brought into the program.

Summary of Section 95990(k)(1).

Existing section 95990(k)(1) is modified to require that an offset project must be listed under a COP by February 28, 2015, in order to eligible to transition from an early action offset project to a COP.

Rationale for Section 95990(k)(1).

This change is needed to clarify that an OPO or APD must list the offset project under a COP by February 28, 2015 in order to transition an early action offset project to a COP. This section now clarifies that listing is achieved by submitting the listing information in section 95975 to ARB or an OPR and having that information approved.

Summary of Section 95990(k)(1)(C).

Existing section 95990(k)(1)(C) is modified to correct the name of the COP for ODS destruction projects.

Rationale for Section 95990(k)(1)(C).

This change is needed to ensure that the name of the COP for ODS destruction projects in this section is correct.

Summary of Section 95990(k)(1)(D).

Existing section 95990(k)(1)(D) is modified to clarify that forest offset projects developed under version 2.1 of the early action forest quantification methodology must calculate a baseline from offset project commencement under the EAOP through project transition, plus 100 years. This section is also modified to correct punctuation.

Rationale for Section 95990(k)(1)(D).

This change is needed to clarify that an OPO or APD must calculate the baseline for a forest early action offset project originally developed under version 2.1 when it transitions to a COP by recalculating the baseline based on the requirements in the COP from the time of offset project commencement under the EAOP, to the time it transitions to the COP, plus one hundred years. This change is needed to clarify the intent of the Regulation. This change is also needed to correct punctuation in this section.

Summary of Section 95990(k)(1)(E).

Existing section 95990(k)(1)(E) is modified to correct punctuation.

Rationale for Section 95990(k)(1)(E).

This change is needed to correct punctuation in this section.

Summary of Section 95990(k)(1)(F).

New section 95990(k)(1)(F) is added to require that when an OPO or APD is transitioning an early action offset project using the potential early action mine methane capture quantification methodologies that staff is proposing to be adopted by the Board, they must use the proposed Compliance Offset Protocol Mine Methane Capture Projects Protocol.

Rationale for Section 95990(k)(1)(F).

This section is needed to require OPOs and APDs of early action offset projects developed under the potential early action mine methane capture quantification methodology to use the staff-proposed ARB COP for mine methane capture projects.

Summary of Section 95990(k)(3)(C).

Existing section 95990(k)(3)(C) is modified to require that an Offset Verification Statement is submitted to the EAOP to complete the verification requirements for transitioning to a COP.

Rationale for Section 95990(k)(3)(C).

This change is needed to clarify that an Offset Verification Statement must be submitted to an EAOP to complete verification and qualify to transition to a COP. Verification in this section refers to the verification performed under the EAOP.

Summary of Section 95990(k)(5).

New section 95990(k)(5) is added to require that all ARB offset credits issued for early action be issued by ARB by August 31, 2016.

Rationale for Section 95990(k)(5).

This section is needed to ensure that all actions to transition early action offset credits to ARB offset credits are completed by August 31, 2016. This will give early action participants enough time to complete all transition activities and gives ARB certainty for when crediting under the early action program component of the Regulation will end.

Summary of Section 95990(l)(1).

Existing section 95990(l)(1) is modified to apply the invalidation requirements in this section to ARB offset credits issued to urban forest projects and ARB offset credits issued to U.S. forest projects after the effective date of these amendments.

Rationale for Section 95990(l)(1).

This change is needed to streamline the requirements for invalidation of ARB offset credits issued in lieu of early action offset credits, with the requirements in section 95985.

Summary of Section 95990(l)(1)(A).

Existing section 95990(l)(1)(A) is modified to remove the requirement that an OPO or APD must be issued ARB offset credits for the invalidation rules of this section to apply.

Rationale for Section 95990(l)(1)(A).

This change is needed because an OPO or APD may not be issued ARB offset credits as they may request the ARB offset credits to be issued to another third-party.

Summary of Section 95990(l)(2).

Existing section 95990(l)(2) is modified to clarify that this section refers to U.S. forest projects and that the provisions in this section apply to the invalidation requirements of ARB offset credits issued to U.S. forest projects prior to the effective date of these amendments.

Rationale for Section 95990(l)(2).

This change is needed to streamline the requirements for invalidation of ARB offset credits issued in lieu of early action offset credits, with the requirements in section 95985.

Summary of Section 95990(l)(3).

New section 95990(l)(3) is added to include requirements that an OPO or APD must meet to shorten the invalidation timeframe for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects.

Rationale for Section 95990(l)(3).

This section is added in response to stakeholder comments that additional scenarios are needed to allow offset projects that originate as early action to reduce the invalidation timeframe.

Summary of Section 95990(l)(3)(A).

New section 95990(l)(3)(A) is added to include requirements that an OPO or APD must meet for shortening the invalidation timeframe for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects that transition to a COP.

Rationale for Section 95990(l)(3)(A).

This section is added in response to stakeholder comments that additional scenarios are needed to allow offset projects that originate as early action to reduce the invalidation timeframe.

Summary of Section 95990(l)(3)(A)(1.).

New section 95990(l)(3)(A)(1.) is added to clarify the verification requirements that must be met to shorten the invalidation timeframe for U.S. forestry, urban forestry, livestock, and mine methane capture projects that originate as early action.

Rationale for Section 95990(l)(3)(A)(1.).

This section is needed to clarify the requirements to shorten the invalidation timeframe for U.S. forestry, urban forestry, livestock, and mine methane capture projects. An ARB-accredited verification body must conduct offset verification services for a subsequent Offset Project Data Report under the COP. Because these project types are continuous projects, with periodic verification requirements, a subsequent verification by an ARB-accredited verification body will ensure there are no inaccuracies or inconsistencies not found in the previous verification.

Summary of Section 95990(l)(3)(A)(2.).

New section 95990(l)(3)(A)(2.) is added to clarify the verification requirements that must be met to shorten the invalidation timeframe for U.S. forestry, urban forestry, livestock, and mine methane capture projects that originate as early action.

Rationale for Section 95990(l)(3)(A)(2.).

This section is needed to require that the subsequent verification be conducted by an ARB-accredited verification body that is a different verification body than has verified the early action offset project before. Because these project types are continuous projects,

with periodic verification requirements, a rotation of verification bodies will ensure that there are no inaccuracies or inconsistencies not found in the previous verification.

Summary of Section 95990(l)(3)(A)(3.).

New section 95990(l)(3)(A)(3.) is added to require that the second verification body must conduct offset verification services for a subsequent Offset Project Data Report to shorten the invalidation timeframe for U.S. forestry, urban forestry, livestock, and mine methane capture projects that originated as early action, within three years of ARB offset credit issuance.

Rationale for Section 95990(l)(3)(A)(3.).

This section is needed to require that the second verification body conduct offset verification services for a subsequent Offset Project Data Report to shorten the timeframe for invalidation for U.S. forestry, urban forestry, livestock, and mine methane capture projects within three years of the issuance of ARB offset credits. Since the invalidation timeframe would be shortened to three years, the subsequent verification needs to occur within those three years.

Summary of Section 95990(l)(3)(B).

New section 95990(l)(3)(B) is added to include requirements that an OPO or APD must meet for shortening the invalidation timeframe for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects that do not transition to a COP.

Rationale for Section 95990(l)(3)(B).

This section is added in response to stakeholder comments that additional scenarios are needed for offset projects that originate as early action to reduce the invalidation timeframe. OPOs and APDs for continuous projects have communicated to ARB that they do not want to wait until they transition to a COP to shorten the invalidation timeframe, which is why staff has added this additional pathway to shorten that timeframe.

Summary of Section 95990(l)(3)(B)(1.).

New section 95990(l)(3)(B)(1.) is added to clarify the verification requirements that must be met to shorten the invalidation timeframe for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects that originate as early action, and do not transition to a COP.

Rationale for Section 95990(l)(3)(B)(1.).

This section is needed to clarify that to shorten the invalidation timeframe for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects that originate as early action and do not transition to a COP, a second verification must be conducted of the original reporting information by a different verification body to ensure that ARB offset credits should have been issued and to ensure there are no inaccuracies or inconsistencies not found in the first verification. A second full regulatory verification must be conducted for projects that will not, or have not yet, transitioned to a COP so that another verification body reviews the work of the OPO or APD.

Summary of Section 95990(l)(3)(B)(2.).

New section 95990(l)(3)(B)(2.) is added to clarify the verification requirements that must be met to shorten the invalidation timeframe for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects that originate as early action and do not transition to a COP.

Rationale for Section 95990(l)(3)(B)(2.).

This section is needed to require that the subsequent verification be conducted by an ARB-accredited verification body that is a different verification body than has verified the early action offset project before. A second full regulatory verification must be conducted for these projects that have not yet transitioned another verification body must review the work of the previous verification body. The verification body must be different to ensure that there are no inaccuracies or inconsistencies not found in the previous verification.

Summary of Section 95990(l)(3)(B)(3.).

New section 95990(l)(3)(B)(3.) is added to require that the second verification body must conduct offset verification services to shorten the invalidation timeframe for ODS destruction projects that originated as early action, within three years of ARB offset credit issuance.

Rationale for Section 95990(l)(3)(B)(3.).

This section is needed to require that the second verification body conduct offset verification services for the same Offset Project Data Report to shorten the timeframe for invalidation for U.S. forestry, urban forestry projects, livestock, and potential mine methane capture projects that originate as early action and do not transition to a COP within three years of the issuance of ARB offset credits. Since the invalidation

timeframe would be shortened to three years, the subsequent verification needs to occur within three years. This section also requires that a site visit be conducted. This is a requirement for all full offset verification services under the Regulation.

Summary of Section 95990(l)(4).

New section 95990(l)(4) is added to include requirements that an OPO or APD must meet for shortening the invalidation timeframe for ODS destruction projects that originate as early action.

Rationale for Section 95990(l)(4).

This section is added to streamline the requirements for invalidation of ARB offset credits for ODS destruction projects with those in section 95985.

Summary of Section 95990(l)(4)(A).

New section 95990(l)(4)(A) is added to clarify the verification requirements that must be met to shorten the invalidation timeframe for ODS destruction projects that originate as early action.

Rationale for Section 95990(l)(4)(A).

This section is needed to clarify that to shorten the invalidation timeframe for ODS projects that originate as early action, a second verification must be conducted of the original reporting information by a different verification body to ensure that ARB offset credits should have been issued and to ensure there are no inaccuracies or inconsistencies not found in the first verification. A second full regulatory verification must be conducted for ODS projects because they are not continuous projects and conclude after the initial verification. Without a second full verification there is not another verification body that reviews any information for the project, as is the case for the other project types that are continuous projects and have periodic verification.

Summary of Section 95990(l)(4)(B).

New section 95990(l)(4)(B) is added to clarify the verification requirements that must be met to shorten the invalidation timeframe for ODS destruction projects that originate as early action.

Rationale for Section 95990(l)(4)(B).

This section is needed to require that the subsequent verification be conducted by an ARB-accredited verification body that is a different verification body than has verified the early action offset project before. A second full regulatory verification must be

conducted for ODS projects because they are not continuous projects and conclude after the initial verification. Without a second full verification there is not another verification body that reviews any information for the project, as is the case for the other project types that are continuous projects and have periodic verification.

Summary of Section 95990(l)(4)(C).

New section 95990(l)(4)(C) is added to require that the second verification body must conduct offset verification services to shorten the invalidation timeframe for ODS destruction projects that originated as early action, within three years of ARB offset credit issuance.

Rationale for Section 95990(l)(4)(C).

This section is needed to require that the second verification body conduct offset verification services for the same Offset Project Data Report to shorten the timeframe for invalidation for ODS destruction projects within three years of the issuance of ARB offset credits. Since the invalidation timeframe would be shortened to three years, the subsequent verification needs to occur within three years.

Summary of Section 95990(l)(5).

New section 95990(l)(5) is added to clarify that the invalidation timeframe begins when ARB offset credits are issued if the ARB offset credits were issued in lieu of early action offset credits.

Rationale for Section 95990(l)(5).

This section is needed to specify that the invalidation timeframe starts from the date that the ARB offset credits are issued if the ARB offset credits were issued in lieu of early action offset credits.

Subarticle 15. Enforcement and Penalties.

Section 96022. Jurisdiction of California.

Summary of changes to section 96022:

This section is being amended to clarify that rights held by entities pursuant to the Foreign Sovereign Immunities Act are not being abrogated by this regulation.

Rationale for changes to section 96022:

This section is being changed to reflect concern on the part of international stakeholders that the cap-and-trade program was attempting to abrogate rights held under the Foreign Sovereign Immunities Act.

Summary of Appendix B

New section Appendix B is added to incorporate the tracking system user terms into the Regulation.

Rationale for Appendix B

This addition is necessary to ensure that the rules for the tracking system are codified in the Regulation as well.

Summary of Appendix C

Appendix C is added to clarify the date of quarterly auctions and Reserve sales from 2015 through 2020.

Rationale for Appendix C

Appendix C is required to clarify dates and to alter the date of the Reserve sale immediately preceding the compliance obligation on November 1 pursuant to Board Resolution 12-51.

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California Environmental Protection Agency
Air Resources Board

Proposed Regulation to Implement the California Cap-and-Trade Program

APPENDIX A

STAFF REPORT AND PROPOSED COMPLIANCE OFFSET PROTOCOL

MINE METHANE CAPTURE PROJECTS

Release Date: September 4, 2013

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State of California
California Environmental Protection Agency
AIR RESOURCES BOARD
Stationary Sources Division

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION TO IMPLEMENT THE CALIFORNIA CAP-AND-TRADE PROGRAM

APPENDIX A

STAFF REPORT AND COMPLIANCE OFFSET PROTOCOL

MINE METHANE CAPTURE PROJECTS

Public Hearing to Consider the Proposed Regulation to Implement the California Cap-and-Trade Program

Date of Release: September 4, 2013
Scheduled for Consideration: October 24-25, 2013

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

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Staff Report

I. Introduction and Background on Compliance Offset Protocols

A. Staff Proposal

Staff is recommending the Board adopt a new Compliance Offset Protocol for Mine Methane Capture projects to augment the existing ARB-approved Compliance Offset Protocols and to support the Cap-and-Trade program. This part discusses the development of a Compliance Offset Protocol for Mine Methane Capture (MMC) projects.

B. Rationale for Compliance Offset Protocols

The Air Resources Board's (ARB or Board) Cap-and-Trade program allows the use of offsets, which are greenhouse gas (GHG) emission reductions or removal enhancements from uncapped sectors, to comply with reporting entities' emission reduction compliance obligations. Offset credits are issued from projects developed using ARB-adopted Compliance Offset Protocols. Compliance Offset Protocols contain the basic methods and procedures to conduct the offset project and determine its greenhouse gas reduction benefits, including project eligibility criteria, quantification methodologies, procedures for project monitoring, reporting, and verification, and regulatory enforcement requirements established to meet the requirements of the Cap-and-Trade Regulation and of the Global Warming Solutions Act of 2006 (Assembly Bill 32, stats. 2006, ch. 488) (AB 32), such that any ARB-issued offset credits are "real, permanent, quantifiable, verifiable, enforceable, and additional."

C. Board Adoption of Compliance Offset Protocols

At its October 2011 meeting, the Board adopted four Compliance Offset Protocols, including protocols for Livestock Manure (digester) Projects, Ozone Depleting Substances Destruction Projects, Urban Forest Projects, and U.S. Forest Projects. Offset protocols must be adopted by the Board before they can be used to generate ARB offset credits. The final Regulation Order of October 2011 directed the Executive Officer "to develop implementation documents laying out the process for review and consideration of new offset protocols, including a description of how staff will evaluate "additionality," signaling the Board's intention to adopt additional Compliance Offset Protocols in the future. This process has since been developed (CARB 2013) and is publicly available at: http://www.arb.ca.gov/cc/capandtrade/compliance-offset-protocol-process.pdf.

D. Compliance Offset Protocol Structure and Regulatory Requirements

Compliance Offset Protocols consist of two main structural elements: project requirements and project quantification. Project requirements include items such as eligibility, monitoring and reporting, and verification and enforcement provisions. AB 32 requires ARB to adopt regulatory requirements for verification and enforcement of any offset reductions used for compliance purposes. Project quantification identifies the quantification methodologies and equations used in project accounting such as baseline determination and calculation of emissions and emission reductions.

The Cap-and-Trade Regulation itself includes offset program regulatory requirements, including but not limited to, eligibility criteria for start dates, project locations, offset project reporting periods, project document retention, project listing information, project reporting information, verification requirements, and enforcement provisions. Staff has developed the Compliance Offset Protocol for Mine Methane Capture Projects to be consistent with regulatory requirements in the Cap-and-Trade Regulation. Since Compliance Offset Protocols are used in the context of a compliance program, staff has included language in the proposed Compliance Offset Protocol for Mine Methane Capture Projects to refer to the regulatory requirements in the Cap-and-Trade Regulation where needed rather than splitting the offset protocols into separate documents based on regulatory requirements and quantification methodologies. In sections that relate directly to a requirement in the Cap-and-Trade Regulation, text refers readers to the appropriate section(s) of the Regulation.

New Compliance Offset Protocols, including the proposed Compliance Offset Protocol for Mine Methane Capture Projects, will be incorporated by reference into proposed amendments to the Cap-and-Trade Regulation. This incorporation makes the offset protocol document an enforceable regulation. AB 32 exempts quantification methodologies from the Administrative Procedure Act (Government Code, section 11340 *et seq.*) (APA), however those elements of the Compliance Offset Protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each Compliance Offset Protocol identifies sections that are considered quantification methodologies and exempt from APA requirements. Any changes to the non-quantification elements of the Compliance Offset Protocols would be considered a regulatory update subject to the full regulatory development process.

E. Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine any potentially adverse environmental impacts of any potential projects under the compliance offset program. When adopting the first four Compliance Offset Protocols in 2011, ARB determined that adoption and implementation of the Compliance Offset Protocols constitute "projects" as defined by Public Resources Code §21000 et seq. The CEQA Guidelines provides the definition of a project (Title 14,

California Code of Regulations, §15378). As was done in 2011, ARB has included a tiered environmental review of the proposed amendments to the Cap-and-Trade Regulation and the proposed Compliance Offset Protocol for Mine Methane Capture Projects. The specific environmental analysis for the MMC Protocol is contained in Part B of this Appendix.

II. Compliance Offset Protocol for Mine Methane Capture (MMC) Projects

A. Role of Mining and Mine Methane Capture in Climate Change Mitigation

The uncontrolled venting of methane occurs at various categories of mines, including active underground mines, active surface mines, and abandoned underground mines. Methane is emitted from active underground and surface mines when a coal or trona seam is disturbed by the advancement of mining activities and, to a lesser degree, when coal is handled post-mining. At the time of closure and abandonment, methane liberation from underground coal mines decreases but does not stop and, after the initial decline, can continue at a near-steady rate for decades (U.S. EPA CMOP 2004).

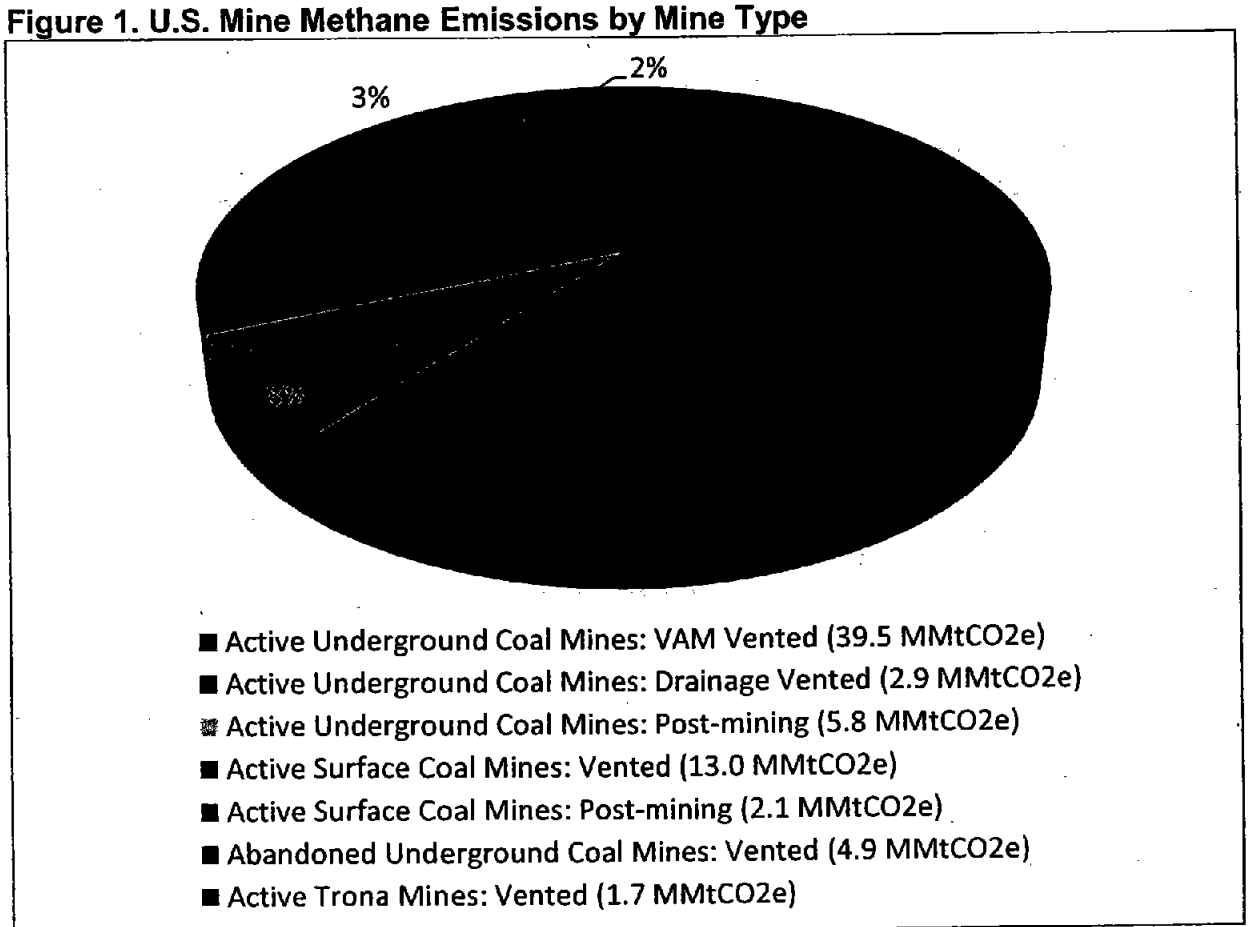
The United States is home to the world's largest reserves of recoverable coal, which is largely used in the generation of electricity (U.S. EIA 2013). Because of the unique adsorptive capacity of coal, the mining of this mineral results in significant methane emissions. Methane is produced during the creation of coal from peat, or "coalification," and is stored within the coal and the natural fractures in the coalbeds known as cleats. Similarly, the mining of trona, a water-bearing sodium carbonate compound that is mined and processed into soda ash or bicarbonate of soda, also releases methane stored in the carboniferous shales above and below the trona seam.

Methane is explosive in concentrations of 5-15% volume in air (U.S. EPA CMOP 2009) and can pose a safety hazard to miners, particularly those at active underground mines. Federal regulations require mines to maintain safe methane levels. To comply with these safety regulations, all underground mines utilize ventilation systems to dilute and remove methane from the mine. At particularly "gassy" mines (i.e., ones which release methane at higher rates), where ventilation systems may not be sufficient to meet safety requirements, drainage systems are employed to extract methane from the seam prior to mining. Despite the requirements to keep methane concentration levels below 1% in mine working places and intake air courses (Title 30, Code of Federal Regulation, 75.323, 2006), no regulations currently exist prohibiting the venting of mine gas from drainage systems or ventilation air methane from ventilation systems or requiring the destruction of this methane.

While methane does not pose the same safety risk at active surface mines and abandoned underground mines, drainage system technology can be employed in those settings for the purpose of mine methane capture.

Mining activities in the United States liberated 89.3 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) in 2011. Just over one fifth of this methane was captured and destroyed, while 69.9 $MMtCO_2e$ was vented into the atmosphere. The resulting mining related emissions accounted for nearly 12% of U.S. anthropogenic methane emissions and 1% of total U.S. GHG emissions that year (U.S. EPA 2013). The graph below (Figure 1) shows a breakdown of the emissions from 2011 by mine type and mining stage.

Figure 1. U.S. Mine Methane Emissions by Mine Type



Adapted from data presented in *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2011* (U.S. EPA 2013) and *Overview of Proposed Abandoned Mine Methane Protocol* (RCE 2013a).

The vast majority of mine methane that was captured, 16.7 $MMtCO_2e$ at active underground mines and 4.9 $MMtCO_2e$ at abandoned underground mines, was injected into natural gas pipelines for offsite usage. In addition to pipeline injection, one mine also utilized captured methane to fuel a thermal coal dryer and another mine destroyed ventilation air methane via thermal oxidation (U.S. EPA 2013). These activities demonstrate the opportunity for significant additional emission reductions from the capture and destruction of mine methane that is currently vented into the atmosphere. Outside of the climate benefits that would result from the destruction of mine methane that is currently vented, additional benefits would be achieved if captured mine methane is utilized for productive purposes such as the generation of electricity or thermal power, production of transportation fuel, or injection into a natural gas pipeline.

B. Development of the Compliance Offset Protocol for Mine Methane Capture Projects

The process of developing the MMC Protocol involved an extensive review of relevant documents and literature as well as a stakeholder process which included soliciting input from industry experts, government agencies, project developers, academia and the general public through a series of workshops, technical working group meetings, and small group discussions.

The MMC Protocol stakeholder process began on March 28, 2013, when ARB staff held a public workshop to discuss the decision to develop potential Compliance Offset Protocols, including the MMC Protocol. During this public stakeholder workshop, ARB invited interested members of the public to participate in an MMC technical working group and in the formal rulemaking process. The technical working group held four meetings through the spring and summer of 2013 during which many topics were addressed, including: the assessment of common practice with regard to natural gas pipeline injection, the feasibility of allowing for projects situated on federal lands, quantification of baseline emissions for projects at abandoned mines using a modeled decline curve, spatial and temporal boundaries applicable to the extraction and quantification of methane drained in advance of mining activities, the merit of accounting for non-methane hydrocarbons, and standards for project expansion. Workshop and meeting materials are available on the MMC Protocol website: http://www.arb.ca.gov/cc/capandtrade/protocols/mmcprotocol.htm. Staff also had many other interactions with stakeholders interested in discussing protocol related issues, and this staff proposal reflects those discussions.

As part of its development of this protocol, ARB staff reviewed existing voluntary market offset protocols to evaluate their scope, additionality provisions, GHG assessment boundary, quantification methodologies, and requirements for monitoring, reporting, and verification. ARB staff also reviewed publicly available documents from the U.S. EPA Coalbed Methane Outreach Program and documents submitted by technical experts and other stakeholders in the development of the MMC Protocol. These documents are included in the reference section of this staff report, and are cited when relied upon for facts. Staff also had interactions with the U.S. Bureau of Land Management, the U.S. Mine Health and Safety Administration, and state agencies responsible for overseeing mining activities. The proposed MMC Protocol is the first "umbrella style" protocol for mine methane, covering emissions from active underground mines, active surface mines, and abandoned underground mines. The MMC Protocol incorporates elements from many of the existing voluntary methodologies as well as the best available science and information to ensure that emission reductions are real, permanent, quantifiable, additional, verifiable and enforceable.

A draft version of the MMC Protocol was made publicly available in August 2013. ARB staff again sought and incorporated input from stakeholders into the proposed final version for Board consideration released along with this staff report for public review on

September 4, 2013. The formal 45-day public comment period begins on September 9, 2013 and the new Compliance Offset Protocol will be considered at the October 24 and 25, 2013 Board hearing along with the proposed amendments to the Cap-and-Trade Regulation.

C. Description of the Compliance Offset Protocol for Mine Methane Capture Projects

1. Overview

ARB's proposed MMC Protocol incentivizes the reduction of GHG emissions resulting from coal and trona mining activities in the United States. The MMC Protocol will allow for the issuance of carbon offset credits for emission reductions achieved from the installation and operation of a device or set of devices that capture and destroy methane that would otherwise be released into the atmosphere as a result of mining activities at active underground mines, active surface mines, and abandoned underground mines. The MMC Protocol is applicable to projects within the United States. The MMC Protocol excludes projects from U.S. territories as there are no coal or trona mines located in territories of the United States.

The MMC Protocol allows for four types of activities:

- Active Underground Mine Ventilation Air Methane (VAM) Activities;
- Active Underground Mine Methane Drainage Activities;
- Active Surface Mine Methane Drainage Activities; and
- Abandoned Underground Mine Methane Recovery Activities

Project activities will vary depending upon the mine classification type and existing infrastructure as well as the end-use management option employed and technology utilized. All MMC projects will involve the capture and destruction of mine methane via an eligible end-use management option (i.e., oxidation, flaring, electricity or heat generation, injection into a natural gas pipeline, production of transportation fuels, etc.) as defined in the MMC Protocol as well as the monitoring of methane destruction. In addition to methane capture, destruction and monitoring that will occur at all projects, some MMC projects would also involve the extraction, transport, and processing of mine gas or ventilation air methane.

The MMC Protocol provides project definitions, eligibility rules, conservative GHG emission reduction quantification methodologies, and procedures for offset project monitoring, reporting, and verification. All projects that pass the eligibility requirements set forth in the MMC Protocol and the Cap-and-Trade Regulation are eligible to register GHG reductions for the duration of the project crediting period, which is ten years.

2. Additionality

Per AB 32 and the Cap-and-Trade Regulation, emission reductions achieved under Compliance Offset Protocols must be additional to what would have occurred in the absence of the project in a conservative business-as-usual scenario. Similar to the Compliance Offset Protocols approved by the Board in 2011, which ensured additionality by utilizing a regulatory additionality requirement and a performance standard approach, the MMC Protocol ensures compliance with the Regulation's additionality requirement through a performance standard evaluation and assessment of legal requirements.

The performance standard is an identified standard of performance applicable to all MMC projects. The purpose of a performance standard is to establish a threshold that is significantly better than average, business-as-usual greenhouse gas (GHG) emissions for a specified activity, which, if met or exceeded by a project developer, satisfies the criterion of "additionality." If the project meets the threshold, then it exceeds what would happen under the business-as-usual scenario and generates additional GHG reductions. 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.

In addition to the performance standard, projects must show regulatory additionality, meaning that there are no federal, state or local laws, regulations or legally-binding mandates requiring the destruction of mine methane. In addition, projects must comply with all applicable local, state, and federal regulations, whether for air and water quality, energy regulations, or others.

Performance Standard Evaluation for Active Surface and Abandoned Underground Mines. Based on ARB staff's review of existing literature (U.S. EPA CMOP 2008a; U.S. EPA CMOP 2008b; U.S. EPA CMOP 2011; U.S. EPA CMOP 2012) and the stakeholder discussions described above, from the population of active surface mines and abandoned underground mines in the United States, few currently capture and destroy mine methane. Methane capture and destruction is therefore deemed not to be business-as-usual at these mines, which means that active surface mine methane drainage activities and abandoned underground mine methane recovery activities are deemed additional.

Performance Standard Evaluation for Active Underground Mines. In the case of active underground mines, ventilation and methane drainage systems have been employed at mines as a strategy for compliance with the safety regulations described in section II.A. above. All active underground mines have ventilation systems, yet only a small fraction destroy the methane released through the ventilation shaft(s) (U.S. EPA CMOP 2012; U.S. EPA CMOP 2011; U.S. EPA CMOP 2008c). VAM capture and destruction is therefore deemed not to be business-as-usual, which means that active underground mine VAM activities are deemed additional. Conversely, only 25 particularly gassy active underground mines, out of a population of over 500, utilized a methane drainage system in addition to a ventilation system in 2012 (RCE 2013b; U.S. EIA 2012). As previously mentioned, mine operators are under no obligation to capture or destroy the

extracted methane, but because the installation of a methane drainage system is considered a response to regulation (U.S. EPA CMOP 2009; SAIC 2009), common practice is assessed by examining the practices of the smaller population of active underground mines with existing methane drainage systems. Most active underground mines with drainage systems inject into a natural gas pipeline (U.S. EPA 2013; U.S. EPA CMOP 2010). Where mine methane is not injected into a pipeline it is usually because pipeline injection has been deemed to be infeasible, either due to the distance or rough terrain between the mine and a transmission line or low annual methane liberation rates (SAIC 2009; U.S. EPA CMOP 2012; U.S. EPA CMOP 2008c). Based on ARB staff's review of the existing practice, and to ensure a conservative assessment of business-as-usual, pipeline injection is deemed to be business-as-usual for underground mines with methane drainage systems. Injection into a natural gas pipeline is therefore not considered additional and is not an eligible end-use management option for active underground mine methane drainage activities in terms of offset credit issuance under the proposed MMC Protocol. Alternative methane destruction methods, including generation of electricity or thermal power, production of transportation fuel, or flaring, are not business-as-usual and therefore deemed additional and eligible under the MMC Protocol.

Legal Requirements. Emission reductions 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. If any 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, only emission reductions resulting from the capture and destruction of mine methane that are in excess of what is legally required are eligible for crediting under this Protocol, subject to a performance standard evaluation as described above.

3. Permanence

Project operators may choose from a variety of eligible methane destruction technologies, but in order to be eligible for crediting under the MMC Protocol, the ultimate fate of the captured mine methane must be destruction. Due to the fact that the Cap-and-Trade Regulation requires claimed emission reductions to be verified prior to the issuance of offset credits and that the destruction of methane does not pose a risk for reversal, GHG emission reductions resulting from the installation and operation of a device or set of devices that capture and destroy methane are permanent.

One of the issues discussed during the Technical Working Group meetings related to the potential eligibility of MMC projects on federal lands, given that the Compliance Offset Protocol for U.S. Forest Projects excludes projects on federal lands due to issues

related to sovereignty and permanence. Based on ARB staff's review of existing permitting and safety regulations, as well as discussions with the U.S. Bureau of Land Management and the U.S. Mine Health and Safety Administration, these same issues do not exist for MMC projects. As such, MMC projects on federal lands are eligible if they meet the requirements of the Cap-and-Trade Regulation and the MMC Protocol. With respect to the AB 32 requirement that any offset credits be subject to ARB enforcement, ARB staff notes that it is unlikely that ARB's enforcement authority would conflict with the mission or authority of the Bureau of Land Management or any other federal agency responsible for overseeing coal and gas leases on federal lands.

Finally, while MMC projects on federal lands could be impacted by changes to policies or management practices prescribed by relevant agencies, such changes would not be retroactively effective nor call into question any offset credits issued for emission reductions achieved prior to new regulatory promulgation. ARB will continue to monitor the adoption of new or modified regulations that could affect the performance standard or legal requirement assessment and warrant a change to an existing Compliance Offset Protocol. Any amendments to an existing Compliance Offset Protocol would involve the same APA process as developing a new Compliance Offset Protocol. If ARB updates an existing Compliance Offset Protocol, the previous version would no longer be used by new projects from the date that Office of Administrative Law approves the new version. Any existing projects under the previous version of the Compliance Offset Protocol would be required to use the new version of the Compliance Offset Protocol once the existing crediting period has ended.

4. Leakage

Per the Cap-and-Trade Regulation, offset protocols must conservatively account for activity-shifting and market-shifting leakage risks associated with an offset project. Activity-shifting leakage is defined as increased GHG emissions or decreased GHG removals that result from the displacement of activities or resources from inside the offset project's boundary to locations outside the offset project's boundary as a result of the offset project activity. Market-shifting leakage is defined as increased GHG emissions or decreased GHG removals outside an offset project's boundary due to the effects of an offset project on an established market for goods or services. ARB staff examined the potential for leakage and determined that there is no risk of leakage associated with the MMC Protocol.

The prospect of activity-shifting leakage is not a concern because the MMC Protocol does not inhibit or interfere with the normal mining operations at a project site. The MMC Protocol does not place limitations on mining activities and would not impact the production of coal at a mine operating an offset project. Because mining activities are not restricted by the MMC Protocol, there is no potential for the displacement of such activities to outside of the project boundary. Therefore there is no risk of activity-shifting leakage.

The MMC Protocol provides a financial incentive for mine operators to capture and destroy mine methane that would otherwise be released into the atmosphere as a result of mining activities. ARB staff examined concerns raised over the impact of this additional revenue stream on coal mining production and found that the potential revenue from offsets is generally less than one percent of the revenue a mine operator would take in from the sale of coal. This conclusion was reached by evaluating mine methane emissions reported to the U.S. EPA and reasonable assumptions of the price of carbon offsets compared to the coal production and sale price data contained in the U.S. Energy Information Administration's Annual Coal Report 2011 (U.S. EIA 2012). The annual coal report compiles information collected from coal mining companies who owned a mining operation that produced 25,000 or more short tons of coal during the reporting year. A less than one percent increase in coal mining revenue from the sale of earned offset credits is not considered substantial enough to impact the established market and therefore does not pose a risk of market-shifting leakage.

ARB staff also considered the possibility of the MMC Protocol's impact on coal production within the project boundary as highlighted and accounted for in the U.N.'s Clean Development Mechanism (CDM) methodology. The logic behind the CDM methodology is that coal production could increase at an underground mine where constraints on mining are reduced through utilization of enhanced methane drainage that could result in the opening up of previously unsafe areas for mining. After examining the rationale behind the international CDM protocol, ARB staff determined that this concern is not applicable to mines in the United States. The potential increase in coal production envisioned by the CDM methodology is primarily an issue in China where gob wells are rarely, if ever, used. (John Savage, personal communication, June 26, 2013). In the United States, gob wells are ubiquitous at underground mines with drainage systems because the potential revenue from the extraction and sale of coal is sufficient to incentivize methane drainage in the absence of the offset project. Drainage capacity and the resulting mining capacity would therefore not be enhanced but rather on par with that which would have taken place without the project. At active underground mines, the protocol is likely to only incentivize the capture and destruction of mine methane, not additional drainage that reduces constraints on mining. No impact on the quantity or speed of coal production is expected as a result of implementation of the MMC Protocol.

5. Quantification Methodologies

The quantification methodologies contained in the MMC Protocol are derived from the Kyoto Protocol's Clean Development Mechanism methodology ACM0008 V.6 (March 25, 2009); the two Verified Carbon Standard approved methodologies specifying revisions to ACM0008: VMR0001 developed by Ruby Canyon Engineering, Inc. (March 30, 2009) and VMR0002 developed by Vessels Coal Gas, Inc. (July 19, 2010); the Climate Action Reserve's Coal Mine Methane Project Protocol V1.1 (October 26, 2012); two draft protocols developed by Ruby Canyon Engineering, Inc. (March 11, 2013, revised draft: July 16, 2013); and the U.S. EPA Coalbed Methane Outreach Program's

Methane Emissions From Abandoned Coal Mines in the United States: Emission Inventory Methodology and 1990-2002 Emissions Estimates (April 2004).

The calculation methodologies in the MMC Protocol include emissions and emission reductions from mine methane extraction, capture, transport, treatment, storage, and destruction. In addition to methane, carbon dioxide emissions from the combustion of methane and the additional energy consumed by project equipment are also accounted for as part of these methodologies. Quantification methodologies rely upon monitored data including: flow rate, volume or mass, methane concentration, temperature and pressure of ventilation air methane or mine gas sent to destruction devices, as well as the operation time and efficiency of destruction devices. The MMC Protocol contains explicit monitoring, reporting, and verification requirements to ensure that the issuance of offset credits coincides with the amount of methane being destroyed.

Quantification of the baseline emissions for an abandoned underground mine methane recovery activity requires the use of an emission rate decline curve that relies upon existing mine-specific emission rate data and national decline curve coefficients derived from basin specific coefficients originally published by the U.S. EPA's Coalbed Methane Outreach Program (U.S. EPA CMOP 2007). This curve predicts the quantitiy of methane emissions that would be emitted from an abandoned mine in the absence of an MMC project for every year after mine closure. Members of the firm Ruby Canyon Engineering Inc. were involved in the development of the U.S. EPA emission inventory methodology for abandoned mines and, in conjunction with the discussions of the Technical Working Group, proceeded to develop a single set of decline curve coefficients (RCE, 2013e). The coefficients provided in the MMC Protocol are the mean results of a Monte Carlo simulation. The use of these coefficients results in a conservative estimation of the baseline emissions of methane at abandoned mines. There is, however, still uncertainty associated with these coefficients based on national averages. For this reason, the MMC Protocol applies a 20% uncertainty deduction to the emission reductions achieved by an abandoned mine methane recovery activity that relies upon the standardized coefficients provided. Alternatively, Offset Project Operators may choose to develop their own mine-specific coefficients using the methodology provided in the MMC Protocol. Mine specific coefficients must be demonstrated to the satisfaction of the Executive Officer as being equally or more accurate than the default hyperbolic decline curve coefficients. Finally, because a project at an abandoned mine is likely to utilize a vacuum to extract methane and this would result in methane leaving the mine at a quicker pace than would occur naturally, the MMC Protocol stipulates that the emission reductions must be equal to or less than the baseline emissions for that reporting period. This ensures that offset credits are not issued for emission reductions beyond the methane emissions that would have occurred during the reporting period in the absence of the project.

Based on the stakeholder engagement described previously, ARB staff believes that the impact of non-methane hydrocarbons (NMHC) on emission reduction calculations is insignificant, and because of the uncertainty of the global warming potential (GWP) of NMHC (Collins et al. 2002), emissions from the venting and combustion of NMHC are

excluded from the GHG assessment boundary. The omission of NMHC from the baseline and project scenarios is conservative since the GWPs (applicable to baseline quantification where NMHC are vented) are greater than their carbon emission factors (applicable to project quantification where NMHC are combusted) for the NMHC commonly found in mine gas, including specifically ethane, butane, and propane (Solomon, et al. 2007; Sindicatum Sustainable Resources 2013).

6. Monitoring, Reporting, and Verification

Offset Project Operators (OPOs) or Authorized Project Designees (APDs) are responsible for monitoring the performance of the project and operating each component of the collection and destruction system in a manner consistent with the manufacturer's specifications.

The volumetric or mass gas flow, methane concentration, temperature, and pressure of ventilation air methane or mine gas from each methane source (i.e., ventilation shaft, pre-mining surface wells, pre-mining in-mine boreholes, post-mining gob wells, etc.) must be monitored separately prior to interconnection with other methane sources except under specific conditions articulated in the MMC Protocol. The MMC Protocol contains explicit requirements for monitoring and recording these parameters.

Operational activity of the methane drainage and ventilation systems as well as the destruction devices must be monitored and documented at least hourly to ensure actual methane destruction. If for any reason the destruction device or the operational monitoring equipment is inoperable, then all metered gas going to the particular device is assumed to be released to the atmosphere during the period of inoperability. GHG reductions will not be accounted for (nor credited) during periods in which the destruction device is not operational.

In addition, the MMC Protocol includes quality assurance and quality control (QA/QC) requirements for monitoring equipment, including gas flow meters and methane analyzers. The MMC Protocol includes a data substitution methodology applicable only to gas flow metering and methane concentration parameters. Data substitution is not allowed for equipment that monitors the proper functioning of destruction devices such as thermocouples.

OPOs or APDs must report GHG emission reductions resulting from project activities and submit Offset Project Data Reports (OPDRs) annually. The MMC Protocol and the Cap-and-Trade Regulation include specific requirements for these OPDRs, which must be verified by an ARB-accredited offset verification body prior to credit issuance. For transparency, project information will be made publically available.

III. Environmental Impacts Analysis

A. Introduction

This chapter of the Staff Report provides an environmental analysis (EA) that evaluates the environmental impacts of the proposed Compliance Offset Protocol for Mine Methane Capture (MMC Protocol) amendment to the 2010 California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (Cap-and-Trade Regulation).

Based on ARB's review of the proposed MMC Protocol, staff determined that it would have potentially significant effects on the physical environment. ARB staff utilized the CEQA Guidelines Checklist to determine whether the proposed protocol may result in potentially adverse environmental impacts. ARB staff determined that implementation of MMC projects would result in no adverse impacts to greenhouse gas emissions and public services. Less than significant impacts were identified for aesthetics, agriculture and forest resources, air quality, energy demand, geology, soils, and minerals, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, population and housing, recreation, transportation and traffic, and utilities and service systems. Impacts to biological resources and cultural resources were determined to be potentially significant related to landscape disturbance required for construction of facilities and infrastructure. This analysis provides the basis for reaching this conclusion. This chapter of the Staff Report also discusses environmental benefits expected from implementing the proposed Protocol.

B. Proposed Offset Protocol

1. Description

The proposed MMC Protocol incentivizes the reduction of greenhouse gas (GHG) emissions resulting from mining activities in the United States. The Protocol would allow for the issuance of carbon offset credits for emission reductions achieved from the installation and operation of a device or set of devices that capture and destroy methane that would otherwise be released into the atmosphere as a result of mining. The uncontrolled venting of methane occurs at active underground mines, active surface mines, and abandoned underground mines. Methane can be released both as ventilation air methane (VAM) through ventilation shafts and as mine gas (MG) through methane drainage systems. Methane drainage systems are comprised of individual gas wells and boreholes. The MMC Protocol allows for four types of activity:

- Active Underground Mine VAM Activities;
- Active Underground Mine Methane Drainage Activities;
- Active Surface Mine Methane Drainage Activities; and
- Abandoned Underground Mine Methane Recovery Activities

Captured methane must be destroyed via an eligible end-use management option (i.e., ventilation air methane oxidation, flaring, electricity or heat generation, injection into natural gas pipeline, production of transportation fuels, etc.) as defined in the MMC Protocol. Active underground mine VAM activities, active surface mine methane drainage activities, and abandoned underground mine methane recovery activities may destroy the captured methane by any end-use management option. Active underground mine methane drainage activities may destroy captured methane by any end-use management option other than injection into a natural gas pipeline.

The MMC Protocol provides project definitions, eligibility rules, conservative GHG emission reduction quantification methodologies, and offset project monitoring, reporting and verification instructions. Under this protocol, overall emissions and emission reductions in methane (CH_4) and carbon dioxide (CO_2) are accounted for in determining the net emissions reductions of an MMC project. In addition to CH_4 emissions, the protocol accounts for the CO_2 emissions that result from the combustion of methane. CO_2 emissions that result from additional energy consumption by equipment used to collect, treat, store and destruct methane are also accounted for as are fugitive emissions resulting from natural gas pipeline injection.

The Protocol is described in more detail in Chapter II of this Staff Report.

2. Project Objectives

The primary objectives of offset protocols in the Cap-and-Trade program that are applicable to the proposed MMC Protocol include the following:

a) Ensure Program Cost Effectiveness. AB 32 states that the Board shall adopt rules and regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions in furtherance of meeting the State's GHG reduction goals. Offsets serve to broaden the compliance instrument market to provide greater flexibility to California businesses by offering a wider range of emissions reduction opportunities and greater market liquidity.

b) Encourage Technological Innovation and Reductions from Non-Capped Sectors. Offsets encourage reductions (beyond common business practice and what is required by regulation) from non-capped sources. Offsets support the development of innovative projects and technologies from sources outside capped sectors that can play a key role in reducing emissions both inside and outside California.

c) Decrease GHG Emissions. Offsets decrease GHG emissions in order to achieve the AB 32 mandate.

d) Maximize Environmental Benefits. Offsets maximize the environmental benefits for California.

3. Compliance Responses

Implementation of the MMC Protocol would reduce the amount of GHG emitted relative to a baseline, by altering mine methane management practices. MMC projects would involve the installation and operation of equipment used to capture and destroy methane in mine gas or ventilation air that would otherwise be vented into the atmosphere. While providing quantification methodologies to account for the reduction in methane emissions, the Protocol does not prescribe the use of any particular destruction technologies. Project activities would vary depending upon the mine classification type and existing infrastructure as well as the end-use management option employed and technology utilized. All MMC projects would involve the capture and destruction of mine methane as well as the monitoring of methane destruction. In addition to capture, destruction and monitoring, it is expected that some MMC projects would also involve the extraction, transport, and treating of mine gas or ventilation air methane. It is expected that the following reasonably foreseeable compliance responses would occur as a result of implementing the MMC Protocol:

- Gas Extraction: For active surface mine methane drainage activities and abandoned mine methane recovery activities, it is expected that new wells and boreholes may be drilled at the mine site to extract methane. Drilling of new wells typically involves: construction of a drill pad; use of a drill rig, drill bit, and motor to drill below the surface to a pre-determined depth of the target formation/strata; and insertion of a steel casing and cement barriers to protect any freshwater aquifers. Active underground mine methane drainage activities are less likely to involve the drilling of new wells, because it is expected that they would extract mine gas through drainage systems that would otherwise be installed for mine safety purposes. Well drilling is not expected to take place for active underground mine methane VAM activities. Ventilation air methane is instead captured from the mine ventilation shaft(s), which would still be constructed in the absence of an MMC project.

- Gas Capture: New equipment would be installed at the mine site to capture ventilation air methane from a ventilation system or mine gas from the newly drilled and/or existing wells that make up the drainage system.

- Gas Transport: Natural gas gathering lines may be constructed to transport the captured mine gas to a gas treatment facility or destruction device. Natural gas gathering lines are typically eight to 30 inches in diameter, constructed of steel, have a cathodic protection applied to guard against corrosion, and are buried four feet underground. Gathering lines are not expected to be installed for active underground mine VAM activities, because the available destruction device technology expected to be employed by projects would be installed within 100 feet of the emission source, the ventilation air exhaust.

- Gas Treatment: Depending upon the methane content of the mine gas and the end-use management option employed, new equipment may be installed at the mine site to treat the mine gas extracted from a drainage system. Gas treatment is largely characterized by dehydration and separation to remove water and other gas components and compression as appropriate for the selected end-use. Gas treatment equipment is not expected to be installed for active underground mine VAM activities.

- Gas Destruction: New equipment would be installed at the mine site to destroy the captured methane. Active underground VAM activities would likely utilize an oxidation unit. Other activity types are likely to destroy captured methane via either a flare or through productive utilization such as electricity or thermal energy production, transformation to compressed natural gas (CNG) or liquefied natural gas (LNG), and natural gas pipeline injection. The MMC Protocol does not limit methane destruction to this list of end-use management options; rather the end-uses described represent known methods of destruction that may be reasonably assumed to be utilized.

- Methane Destruction Monitoring: Some destruction device technologies have sufficient internal monitoring capabilities to meet the standards of the MMC Protocol. Other technologies would require the utilization of separate monitoring equipment. Compliance with the MMC Protocol would involve the use of flow meters and methane analyzers as well as instruments to measure temperature and pressure.

- Construction Activities: Installation of some project equipment, equipment pads, gathering lines, and infrastructure may require site grading, berming, trenching, foundation preparation, delivery of materials and construction equipment, and transport of construction workers to and from the mine site.

C. Impacts and Mitigation Measures

1. Regulatory Setting

As described in the *Functional Equivalent Document prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms* (2010 FED), Compliance Offset Protocols include several elements to support existing health and environmental protection measures. Specifically, each individual offset protocol requires all offset projects to be developed in compliance with all federal, state, and local laws, regulations, ordinances, and any other legal mandate, including all CEQA and National Environmental Policy Act (NEPA) requirements where applicable. The Offset Project Operator is required to attest to ARB that their project meets these requirements. If during verification, it is found that the offset project does not meet any of these requirements, the project is ineligible to be issued ARB offset credits for methane destruction that occurred during the time that the project was out compliance. In

addition to the regulatory compliance requirements, Offset Project Operators must provide detailed information regarding the project at the time of project listing that would be posted on the internet and available for public review.

Many of the compliance responses under the proposed MMC Protocol are regulated activities that require the acquisition of a permit from a relevant governing body or jurisdiction. The Regulatory Setting established in the 2010 FED, and as amended in this EA, includes a number of federal or other laws and regulations that could be applicable to the proposed MMC Protocol and would likely trigger such permitting activity.

a) Mining Regulations

A number of laws apply specifically to mining activities, including the Surface Mining Control and Reclamation Act of 1977 (SMCRA), and the Federal Mine Safety and Health Act of 1977 (Mine Act) as amended by the Mine Improvement and New Emergency Response Act of 2007 (MINER Act). These regulations are applicable and central in the impact analysis contained in this EA and are summarized briefly below:

- SMCRA is the primary legal basis for regulation and permitting of coal mining in the United States. It establishes minimum federal standards that each state must enforce through their own regulatory and permitting programs that govern mining. The Office of Surface Mining, Reclamation and Enforcement (OSMRE) in the U.S. Department of the Interior provides oversight for all regulations and programs under SMCRA nationwide. Where mining occurs on federal lands, or where states have delegated their authority, OSMRE administers SMCRA regulations directly or in coordination with appropriate federal agencies.

  SMCRA applies to all surface coal mining operations in the U.S., as well as the surface effects of underground coal mining. SMCRA regulations affect proposed and existing active mines, as well as many closed or abandoned mines. It establishes detailed permitting procedures and bonding requirements that all states must enforce prior to the issuance of mining permits. These procedures are rigorous and require detailed studies and documentation of the nature and extent of proposed mining operations, existing environmental conditions and potential impacts and mitigation, regulatory compliance activities pursuant to other laws and enforcing agencies (e.g. Clean Water Act, Clean Air Act, Endangered Species Act, National Historic Preservation Act, etc.), and plans for reclamation activities that will be undertaken both during and after mining activities. Detailed environmental performance standards are required for mining on both private and public lands to ensure restoration and reclamation of affected lands to a condition capable of supporting pre-mining conditions or to new higher or better uses. Permit applications must demonstrate how the performance standards will be achieved.

- The Mine Act applies health and safety regulations to all active mining operations in the U.S. and is administered by the Mine Safety and Health Administration (MSHA) in the U.S. Department of Labor. MSHA's Coal Mine Safety and Health Division administers regulations applicable to coal mining, while the Metal and Nonmetal Mine Safety and Health Division administers regulations applicable to all other forms of mining.

  Under the Mine Act, MSHA conducts safety inspections biannually at surface mines and quarterly at underground mines. Included in these inspections are proper installation and operation of ventilation systems to reduce coal mine methane and other gases that are hazardous to mine worker health. Accordingly, MSHA also has permitting and inspection authority over the installation of mine methane ventilation and drainage systems, as well as methane capture and destruction devices or technologies similar to those described above under Compliance Responses.

  The provisions of the MINER Act introduced more comprehensive emergency response planning to mitigate numerous potential hazards associated with mining, and imposes more stringent enforcement provisions and penalties relative to Mine Act regulations.

A number of additional updates to the Regulatory Setting in the 2010 FED are summarized below. These updates are applicable to the MMC Protocol, and may be applicable to other potential future protocols to be developed as part of the Cap-and-Trade program.

b) Cultural Resources:

- Archaeological Resources Protection Act (ARPA): requires protection of archaeological resources and sites on federal public lands and Native American lands.

- Paleontological Resources Preservation Act: requires the U.S. Secretary of the Interior to manage and protect paleontological resources on federal public lands using scientific principals and expertise.

c) Hazardous Materials

A number of federal laws administered by the U.S. EPA and/or state agencies throughout the nation govern the use, storage, and disposal of hazardous substances. These generally include the following:

- Resources Conservation and Recovery Act (RCRA): establishes regulations for hazardous waste management in Section C.

- Hazardous and Solid Waste Amendments Act: hazardous waste management

- Comprehensive Environmental Response Compensation and Liability Act (CERCLA): cleanup of contamination and contaminated sites

- Superfund Amendments and Reauthorization Act (SARA): cleanup of contamination and contaminated sites

- Emergency Planning and Community Right-to-Know: business inventories and emergency response planning

- Toxic Substances Control Act (TSCA): tracking and screening industrial chemicals

- Federal Insecticide, Fungicide, and Rodenticide Act: pesticide distribution, sale, and use.

d) Transport of Hazardous Materials

- Pipeline Safety, Regulatory Certainty, and Job Creation Act (2011): provides for enhanced safety, reliability and environmental protection in the transportation of energy products by pipeline. Regulations promulgated under the Act will be administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) in the U.S. Department of Transportation.

As described in the 2010 FED, Compliance Offset Protocols include several elements to support existing health and environmental protection measures. Specifically, each individual offset protocol requires all offset projects to be developed in compliance with all federal, state, and local laws, regulations, ordinances, and any other legal mandate, including all CEQA and NEPA requirements where applicable. The Offset Project Operator is required to attest to ARB that their project meets these requirements. If during verification, it is found that the offset project does not meet any of these requirements, the project is ineligible to be issued ARB offset credits for methane destruction that occurred during the time that the project was out compliance. In addition to the regulatory compliance requirements, Offset Project Operators must provide detailed information regarding the project at the time of project listing which will be posted on the internet and available for public review.

This analysis is necessarily programmatic in nature because site-specific or project-specific aspects of environmental impacts cannot be precisely described at this time since the specific location, type, and number of offset projects that would occur under this protocol in-state and out-of-state cannot be known and are dependent upon a variety of factors that are not within the control of ARB, including economic costs, offset demand, permitting requirements, environmental constraints, and other market constraints. Therefore, this EA addresses broadly defined types of impacts without

the ability to determine the specific GHG reduction action or offset project locations, project size and character, or site-specific environmental characteristics. In light of these uncertainties, staff took a conservative approach in its evaluation in order to satisfy the good-faith, full-disclosure intent of CEQA.

2. Beneficial Impacts

In accordance with ARB's CRP, as well as considering the legislative intent of AB 32 and the latitude under CEQA to recognize environmental co-benefits (beneficial impacts), this EA incorporates discussion of potential beneficial environmental impacts when those impacts are considered reasonable and foreseeable, and they are relevant to the decisions to be made by ARB regarding the proposed MMC Protocol. In most instances it is not possible to quantify these impacts at this level because of the broad nature of this programmatic analysis. At a project specific level the quantification of beneficial impacts would be possible. Any beneficial impacts associated with the proposed Compliance Offset Protocol will be included in the impact assessment for each resources area listed below.

3. Resource Area Impacts

The environmental assessment in this EA is necessarily programmatic in nature. Site-specific or project-specific aspects of environmental impacts cannot be precisely described at this time, because the specific location, type, and number of offset projects that would occur under this protocol in-state and out-of-state cannot be known and are dependent upon a variety of factors that are not within the control of ARB, including economic costs, offset demand, permitting requirements, environmental constraints, and other market constraints. Therefore, this EA addresses broadly defined types of impacts without the ability to define the specific GHG reduction actions or offset project locations, project size and character, or site-specific environmental characteristics. In light of these uncertainties, the EA uses a conservative approach in its evaluation to satisfy the good-faith, full-disclosure intent of CEQA.

Where potentially significant impacts were identified, feasible mitigation measures have been identified. However, because ARB is not responsible for implementation of project-specific mitigation and the programmatic analysis does not allow project-specific details of what impacts would definitively occur or the effectiveness of any specific mitigation, there is inherent uncertainty in the degree of mitigation ultimately implemented to reduce potentially significant impacts. Consequently, while it is reasonable to expect that mitigation and regulatory compliance would resolve potentially significant environmental impacts, the EA takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable.

a) Aesthetics

i. Impacts Analysis

The installation of mine methane gas extraction, capture, transportation, treatment, destruction, and monitoring equipment at active or abandoned mine sites would likely be of similar size, scale, and visual character to those typical of active mining operations. Given that mine locations are generally isolated, it is expected that installation of this equipment under the Protocol would not result in substantial changes to scenic vistas, resources, visual character, or light and glare impacts from active mining operations. Any potential adverse effects would likely be minimized as the result of regulatory oversight, particularly on federal lands as governed by a number of regulations administered and enforced by various federal or state agencies. Relevant and applicable laws and regulations include but are not limited to SMCRA, Forest and Rangeland Renewable Resources Planning Act, Public Rangelands Improvement Act, Federal Land Policy and Management Act, Wild and Scenic Rivers Act, Wilderness Act, and other applicable laws and regulations.

Abandoned mining sites and adjacent areas, however, may have experienced varying degrees of reclamation, reuse and/or redevelopment since mine closure and abandonment, pursuant to SMCRA. OSMRE operates several programs that include best practices and support for geomorphological reclamation and reforestation on abandoned mine lands. Construction of offset projects at abandoned mining sites could thus alter the visual character of such sites and adjacent surrounding areas, or introduce new sources of nighttime lighting that could adversely affect surrounding areas that may have been restored for active public recreation or uses other than mining.

Because specific offset projects at abandoned mines have not yet been identified, the degree to which reclaimed or redeveloped areas at or adjacent to abandoned mines would be affected remains uncertain. However, any MMC projects would be required to comply with federal and state permitting requirements under SMCRA to avoid potential conflicts with forest management, agricultural activities, or other existing land uses on affected reclaimed mining lands. Aesthetic impacts would, therefore, be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

b) Agriculture and Forest Resources

i. Impacts Analysis

The installation of mine methane gas extraction, capture, transportation, treatment, destruction, and monitoring equipment would be situated on either active or abandoned mines throughout the United States. For the most part, MMC projects would be located on land designated for active mining and as such there would be no conversion of Prime Farmland, Unique Farmland, and Farmland of Statewide Importance, or land zoned for agriculture.

In some circumstances, offset projects located at active or abandoned mines could be located within or adjacent to National Forests or other forests protected by state or local authorities. If the mine is situated within or adjacent to a national forest, this would be on federal land, which would trigger NEPA and would require the involvement of the U.S. Forest Service in the environmental analysis. Similarly, offset projects at abandoned sites could conflict with reforestation activities that have taken place subsequent to a mine's closure and abandonment, pursuant to the SMCRA. OSMRE operates several programs that include best practices and support for reforestation on abandoned mine lands. Because specific offset projects at abandoned mines have not yet been identified, the degree to which agriculture or forested areas at or adjacent to abandoned mines would be affected remains uncertain. However, any MMC projects at abandoned mining sites would be required to comply with permitting requirements pursuant to SMCRA to avoid potential conflicts with reforestation activities or restoration of agricultural activities under any approved mine reclamation plans. Therefore, impacts to agriculture and forest resources would be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

c) Air Quality

i. Impacts Analysis

Construction Activities:

The construction activities associated with the installation of gas extraction, capture, transportation, treatment, destruction, and monitoring equipment could cause a temporary increase in criteria pollutant (or precursor) emissions, toxic air contaminant (TAC) emissions, and odors associated with short-term construction activities (e.g., use of heavy-duty construction equipment).

Operational Activities:

Mine gas treatment and methane destruction via certain end-use management options (e.g., oxidation, flaring, etc.) can cause an increase in emissions of sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM_{10}), carbon monoxide (CO), water vapor, and reactive organic gasses (ROG) including volatile organic compounds (VOCs). Alternatively, emissions of VOCs could also be reduced as a result of their combustion along with the methane. TAC emissions and odors could also be generated as a result of offset project operations.

A net increase in criteria pollutant (or precursor) emissions is not allowed in locations designated as nonattainment areas per the National Ambient Air Quality Standards (NAAQS). The potential emissions from projects located in these areas would need to be considered in the context of a state implementation plan (SIP) to bring an area back into compliance.

All projects implemented under the MMC Protocol must be in accordance with all applicable federal, state, and local regulations and regulatory oversight requirements in order to be issued credits for emission reductions. These regulatory requirements could include, but would not be limited to, the following:

- Compliance with all appropriate air quality permits for project construction and operations from the local agencies with air quality jurisdiction and from other applicable agencies (e.g., U.S. EPA), if appropriate, prior to construction mobilization.

- Compliance with the CAA and the CCAA (e.g., NSR and BACT criteria if applicable).

- Compliance with local plans, policies, ordinances, rules, and regulations regarding air quality-related emissions and associated exposure.

- Coordination with local land use agencies to seek entitlements for development including completing all necessary environmental review requirements (e.g., NEPA if federal action is involved, local entitlements).

- Based on the results of the environmental review, proponents would be required to implement all mitigation identified in the environmental document. Local or state land use agencies or governing bodies would also certify that the environmental document was prepared in compliance with applicable regulations.

- For projects located in PM nonattainment areas, preparation and compliance with a dust abatement plan that addresses emissions of fugitive dust during construction and operation of the project.

Consequently, the 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 required compliance with laws and regulations. Therefore, implementation of the MMC Protocol would not result in a conflict with adopted air quality plans, violation of NAAQS or other air quality standards, and/or cumulatively significant increases in criteria pollutants. Impact to air quality would be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

d) Biological Resources

i. Impacts Analysis

The installation of gas extraction, capture, transportation, treatment, destruction, and monitoring equipment could cause direct and indirect adverse impacts to special status species and habitats. Direct impacts to special status species and habitats may result

from, but not be limited to, construction or vehicle travel. Direct mortality could result from destruction of dens, burrows, or nests through ground compaction, ground disturbance, debris, or vegetation removal within mine sites due to compliance response activities. Indirect impacts to animals could result from noise disturbance that might reduce nest or den abandonment and loss of reproductive or foraging potential around the site during construction, transportation, or destruction of equipment.

Most new equipment would be situated on land with existing mining operations where disturbance to natural habitats is expected to already be present. Most facilities exist on sites that are/have been subjected to severe disturbance including grading, trenching, paving, and construction of roads and structures. Daily activities often include the presence of humans, movement of automobiles, trucks and heavy equipment, and operation of stationary equipment. This environment is not considered conducive to many biological resources. Vegetation is often removed or controlled and wildlife displaced to more suitable surroundings. Nonetheless, there are plant and animal species that occur, or even thrive, in developed settings. Also, activities that require disturbance of undeveloped areas, such as the construction of new structures, boreholes, surface wells, roads or paving have the potential to adversely affect plant or animal species that may reside in those areas.

Construction of new equipment may require minor expansion of the development footprint within the existing mine site or affect adjacent or nearby areas where special-status species or sensitive habitats could be present. In some circumstances, offset projects located at abandoned mines could be located within or adjacent to areas where natural habitat has been restored subsequent to a mine's closure or where special status species have occupied the area or site. Because specific offset projects at abandoned mines have not yet been identified, however, the degree to which any restored natural habitats or special status species at or adjacent to abandoned mines would be affected remains uncertain. Consequently, construction activities that could disturb undeveloped areas on the surface (even within the mine site) pose a potentially significant impact to biological resources.

Installation of new wells or boreholes could have the potential to connect with underground aquifers and might cause water removal from aquifers. Removal or interruption of water from aquifers could cause dewatering of streams or springs important to special status species or habitats (such as wetlands or riparian habitat). Consequently, construction activities that disturb aquifer resources could pose a potentially significant impact to biological resources.

Removal of water from mine sites as a result of drilling activities related to the installation of new boreholes or wells and subsequent dispersal of that water over and adjacent to the mine site could cause impacts to soil or water quality from salinization or sodium; especially if it leaches into another aquifer, nearby waterways or open water sources such as ponds. Salinity and sodium or other mineral changes to soils or available water for special status plants or aquatic wildlife could result in toxic impacts. Consequently, construction activities that disturb and distribute non-filtered aquifer

resources could pose a potentially significant impact to biological resources on or adjacent to the mine site.

Because of the possible presence of special status species or habitat that might be directly or indirectly adversely impacted by project implementation, compliance response could result in potentially significant impacts to biological resources. Depending on the status of the species and the nature of the habitat disturbance, compliance with permitting requirements under SMCRA, NEPA, the federal Endangered Species Act, Migratory Bird Treaty Act, Clean Water Act, Section 404, or related state or local laws would be required. Accordingly, the potential impact to special-status species and sensitive habitats would be minimized. However, the possibility cannot be ruled out that a special-status species or its habitat could be adversely affected, even with applicable regulations in place, recognizing the potential changes in habitat expected from MMC Protocol compliance responses under some circumstances. Therefore, a conservative interpretation would warrant a conclusion that impacts to special-status species and their sensitive habitats are considered to be potentially significant.

ii. Mitigation Measures

The appended Regulatory Framework identifies statutes and regulations that provide regulatory protection of biological resources. Additional statutes and regulations may also exist. ARB does not have the authority to require implementation of mitigation that could reduce these potential impacts. The ability to require such measures is under the purview of jurisdictions with local permitting authority. Project-specific impacts and mitigation would be identified during the environmental review by agencies with regulatory authority. Recognized practices that are routinely required to avoid and/or minimize impacts to biological resources include:

- Preparation of a biological inventory of site resources by a qualified biologist prior to ground disturbance or construction. If protected species or their habitats are present, comply with applicable federal and state endangered species acts and regulations. Ensure that important fish or wildlife movement corridors or nursery sites are not impeded by project activities.

- Preparation of a wetland survey of onsite resources. Establish setbacks and prohibit disturbance of riparian habitats, streams, intermittent and ephemeral drainages, and other wetlands. Wetland delineation is required by Section 3030(d) of the Clean Water Act administered by the U.S. Army Corps of Engineers.

- Prohibit construction activities during the rainy season with requirements for seasonal weatherization and implementation of erosion prevention practices.

- Prohibit construction activities in the vicinity of special status nests, dens, burrows or roosts during nesting season or establish protective buffers and provide monitoring as needed to ensure that project activity does not cause an active nest to fail.

- Preparation of site design and development plans that avoid or minimize disturbance of habitat and wildlife resources, and prevents stormwater discharge that could contribute to sedimentation and degradation of local waterways. Depending on disturbance size and location, a National Pollution Discharge Elimination System (NPDES) construction permit may be required from the appropriate state or local enforcement authority under the Clean Water Act.

- Plant replacement trees and establish permanently protection suitable habitat at ratios considered acceptable to comply with local requirements, if necessary.

Because ARB is not responsible for implementation of project-specific mitigation and the programmatic analysis does not allow project-specific details of mitigation, there is inherent uncertainty in the degree of mitigation ultimately implemented to reduce potentially significant impacts. Consequently the EA takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable.

e) Cultural Resources

i. Impacts Analysis

The installation of mine methane gas extraction, capture, transportation, treatment, destruction, and monitoring equipment would be located at both active mining operations as well as abandoned mines. Construction activities related to such installation could include drilling, boring, trenching and other activities that would generally be consistent with ongoing permitted mining activities. However, the scope and extent of additional ground disturbance or related activities could still potentially affect cultural resources in areas not covered by existing permits, particularly subsurface areas at mines or in adjacent lands that were previously undisturbed. Potential adverse effects include direct damage to or destruction of undocumented historical resources of an architectural or archaeological nature; undocumented human remains not interred in cemeteries or marked, formal burials; or unique paleontological resources or sites by ground-disturbance or demolition activities at the surface or in the subsurface, particularly during trenching for underground pipelines and utility infrastructure or drilling new wells or boreholes. Direct impacts to such resources may result from, but not be limited to, the immediate disturbance of the materials, features or deposits, whether from vegetation removal, compaction or vibrations resulting from vehicle travel over the surface, earth-moving activities, excavation, or demolition of overlying structures.

Indirect operational impacts to identified or undocumented historical resources or significant archaeological resources would be related to potential alteration of the resource setting through the introduction of visual project elements that contrast with the setting of the historical or significant archaeological resource and could diminish the integrity of the resource's significant historic features. Other indirect impacts to consider include increased erosion due to clearance and preparation of the project area, or from

inadvertent damage or outright vandalism to exposed resource materials due to improved accessibility. Increased human exposure to sensitive paleontological sites would have the potential to damage or destroy paleontological resources in those areas determined to be paleontologically sensitive.

The potential for discovery of prehistoric or ethno-historic archaeological resources throughout the U.S. where mining activities occur is considered highly sensitive within or near slope or topographic features, or within natural resource collecting areas considered culturally sensitive for Native Americans, such as natural rivers and streams, springs, ponds/lakes, eco-tones, ridge-tops, mid-slope benches, flat benches, meadows, oak groves, and source areas for raw materials. Similarly, the potential for discovery of historic-period archaeological resources is considered highly sensitive within or near areas directly related to areas used historically for industrial, commercial, agricultural or mining activity and related infrastructure, traces of which, such as railroad corridors and bridges, working housing, mining buildings and appurtenant structures, farms, ranches, early mining operations, and other features could occur in virtually any setting or landform.

Because of the possible presence of identified or undocumented historical resources, significant or unique archaeological resources, undocumented human remains, or unique paleontological resources or sites that could be directly or indirectly disturbed, materially altered, or demolished by project implementation, compliance response could result in potentially significant impacts to cultural resources.

Regulatory permitting activities on federally-managed or other lands could include the following activities that would serve to reduce or minimize adverse effects:

- SMCRA requires permitting compliance in coordination with appropriate Federal and State agencies, and includes documentation of cultural resources and potential adverse effects and compliance procedures related to other laws and regulations.

- Section 106 of the National Historic Preservation Act, which requires consultation with the State Historic Preservation Officers, Native American Tribes, and others as appropriate in the event that cultural resources are discovered.

- Consultation with potentially affected Native American tribes pursuant to the Native American Graves Protection and Repatriation Act of 1990 (NAGPRA) would help to ensure the rightful disposition, or repatriation, of Native American remains and items of cultural patrimony that are in federal possession or control, in the event of the inadvertent discovery of human remains of Native American origin.

- The Archaeological Resources Protection Act (ARPA) also governs the excavation of archaeological sites on federal and Native American lands, as well as removal of resources from such sites, on Federal lands.

- Consultation with federal agencies with respect to the potential presence of paleontological resources, pursuant to the Paleontological Resources Preservation Act, and other applicable federal laws and regulations.

While these regulatory activities could serve to reduce or minimize adverse effects on cultural resources, impacts would remain potentially significant under some circumstances where federal, state or local regulatory oversight is limited, or where cultural resource surveys have not been previously conducted and, as a result, resources that may be disturbed by construction have not yet been discovered or documented.

ii. Mitigation Measures

The following mitigation applies to address potentially significant cultural resources impacts:

- Retain the services of cultural resources specialists with training and background that conforms to the U.S. Secretary of Interior's Professional Qualifications Standards, as published in Title 36, Code of Federal Regulations, part 61 (36 CFR Part 61).

- Seek guidance from the State Historic Preservation Officer and federal lead agencies, as appropriate, for coordination of Nation-to-Nation consultations with the Native American tribes.

- Proponents of the MMC offset projects shall consult with lead agencies early in the planning process to identify the potential presence of cultural properties. The agencies shall provide the project developers with specific instruction on policies for compliance with the various laws and regulations governing cultural resources management, including coordination with regulatory agencies and Native American Tribes.

- Proponents of the MMC offset projects shall define the area of potential effect (APE) for each project, which is the area where project construction and operation may directly or indirectly cause alterations in the character or use of historic properties. The APE shall include a reasonable construction buffer zone and laydown areas, access roads, and borrow areas, as well as a reasonable assessment of areas subject to effects from visual, auditory, or atmospheric impacts, or impacts from increased access.

- Proponents of the MMC offset projects shall retain the services of a paleontological resources specialist with training and background that conforms with the minimum qualifications for a vertebrate paleontologist as described in Measures for Assessment and Mitigation of Adverse Impacts to Non-Renewable Paleontological Resources: Standard Procedures, Society of Vertebrate

Paleontology, 1995
http://www.vertpaleo.org/society/polstateconfomimpactmigig.cfm.

- Proponents of the MMC offset projects shall conduct initial scoping assessments to determine whether proposed construction activities, if any, could disturb formations that may contain important paleontological resources. Whenever possible potential impacts to paleontological resources should be avoided by moving the site of construction or removing or reducing the need for surface disturbance. The scoping assessment shall be conducted by the qualified paleontological resources specialist in accordance with applicable agency requirements.

- The project proponent's qualified paleontological resources specialist shall determine whether paleontological resources would likely be disturbed in a project area on the basis of the sedimentary context of the area and a records search for past paleontological finds in the area. The assessment may suggest areas of high known potential for containing resources. If the assessment is inconclusive a surface survey is recommended to determine the fossiliferous potential and extent of the pertinent sedimentary units within the project site. If the site contains areas of high potential for significant paleontological resources and avoidance is not possible, prepare a paleontological resources management and mitigation plan that addresses the following steps:
  a) a preliminary survey (if not conducted earlier) and surface salvage prior to construction;
  b) physical and administrative protective measures and protocols such as halting work, to be implemented in the event of fossil discoveries;
  c) monitoring and salvage during excavation;
  d) specimen preparation;
  e) identification, cataloging, curation and storage; and
  f) a final report of the findings and their significance.
  g) Choose sites that avoid areas of special scientific value.

Because ARB is not responsible for implementation of project-specific mitigation and the programmatic analysis does not allow project-specific details of mitigation, there is inherent uncertainty in the degree of mitigation ultimately implemented to reduce potentially significant impacts. Consequently, the EA takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable.

f) Energy Demand

i. Impacts Analysis

The installation and operation of new equipment for the purpose of mine methane gas extraction, capture, transportation, treatment, destruction, and monitoring could result in additional energy consumption. Implementation of MMC projects would not conflict with existing energy conservation plans, would not require the expansion of existing energy

facilities because of the dispersed location of MMC offset projects and relatively low energy demands compared to the overall mining operations at which offset projects would occur, and would therefore not result in substantial increases in peak energy demands.

Active underground mine methane drainage activities, active surface mine methane drainage activities and abandoned underground mine methane recovery activities may offset the increased energy demand by using the captured methane to power on-site stationary and mobile combustion sources. This could reduce the facility's reliance on fossil fuel demand and would be a beneficial impact of this offset protocol. Projects may also supply additional energy off-site. While the Protocol's quantification methodologies do not recognize greenhouse gas emission reductions associated with potential fossil fuel displacement, increasing the supplies of electricity and natural gas are other potentially beneficial impacts of the MMC Protocol. Impacts on energy demand would, therefore, be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

g) Geology, Soils, and Minerals

i. Impacts Analysis

Construction activities related to MMC offset project implementation could include drilling, trenching, excavation and other activities that are similar to activities that would otherwise occur at active mining operations. However, such activities could still affect geological formations, soils and minerals at mining sites that are not included within the scope of permitted mining activity. The extent to which such resources would be adversely affected depends on the extent of the construction activity at mine sites, the extent to which such activities would affect previously undisturbed soils or surface or subsurface geological formations, and the potential presence or absence of any geologic formation, soil or mineral type that is unique and distinct from what is included in permitted activities. However, because no specific MMC offset project locations or associated project details are known, the possibility of any specific adverse effects that would occur to these resources, or the safety of any specific mining operations, remains uncertain.

In some cases, MMC projects would require the drilling of new methane drainage wells and boreholes, trenching for gathering pipelines, and other activities involving new ground disturbance and excavation. Such activities would either be covered by existing federal or state mining permits or require the advance acquisition of such permits. As noted in the Regulatory Setting, the safety of active and abandoned mining operations are regulated extensively by federal and state agencies pursuant to MSHA, as well as SMCRA, and therefore, permitting and enforcement activities under these regulations would be expected to minimize the exposure of people or structures to any potential adverse effects from implementation of an MMC project incidental to mining activities. This regulatory structure would ensure that adequate measures are in place to prevent

adverse effects to geological and mineral resources, along with any potential adverse effects to mineral resources at these locations.

Some minor soil erosion impacts may result from the installation of new equipment; however, Offset Project Operators would be required to implement MMC projects in accordance with all federal, state and local regulations to control erosion, drainage, and grading pursuant to SMCRA, the Clean Water Act, the Soil and Water Resources Conservation Act and other similar laws. These requirements would ensure that adequate measures would be in place to prevent the substantial erosion of onsite soils. Impacts to geology, soils, and minerals would be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

h) Greenhouse Gas Emissions

i. Impacts Analysis

Methane destruction devices employed as part of an MMC project would result in an increase in CO_2 emissions associated with the combustion of CH_4 in ventilation air and mine gas. These emissions, however, would be in lieu of the release of CH_4, which has a significantly higher global warming potential (GWP) than CO_2. Therefore combustion of CH_4 and the associated conversion to CO_2 results in a net reduction in GHG emissions and the associated climate change impacts would be beneficial.

ii. Mitigation Measures

Mitigation is not warranted.

i) Hazards and Hazardous Materials

i. Impacts Analysis

Methane is not classified by the U.S. EPA as a hazardous material; however, it is classified as a hazardous material in California. While methane is not toxic below the lower explosive limit of 5% (50,000 ppm), it does act as a simple asphyxiate by displacing oxygen in the air at higher concentrations. Symptoms of oxygen deprivation (asphyxiation) will occur if the available oxygen falls below 18%; methane displaces oxygen to 18% in air when present at 14% (140,000 ppm). Methane is extremely flammable and can explode at concentrations between 5% (lower explosive limit) and 15% (upper explosive limit). These concentrations are lower than concentrations at which asphyxiation risk is significant. Mines are therefore in the practice of being well ventilated to maintain safe methane concentration levels at or below 1%, and MSHA regularly conducts mine inspections to ensure compliance with the Mine Act.

The management of hazardous materials and hazardous wastes, such as fuels and solvents used on-site, would require permits from applicable federal, state, and local regulating agencies. Specific applicable laws and regulations that would apply include

(but are not limited to) the Hazardous Waste Program specified under Subtitle C of the Resource Conservation and Recovery Act (RCRA), the Toxic Substances Control Act (TSCA), the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), the Hazardous Materials Transportation Act (HMTA), SMCRA, and other applicable laws and regulations.

It is expected that a mine would already have secured such approval pursuant to these regulations and that the implementation of the project would not substantially change the routine transport, storage, use, and disposition of such hazardous materials and resulting wastes. Should new gas treatment activities take place as a result of MMC project implementation, it is expected that the equipment involved would require a permit to operate and would be subject to regular monitoring and inspection. SMCRA and the Mine Act, as well as regulations enacted in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 would serve to minimize hazards associated with the construction of any gathering pipelines related to compliance activities that would involve transport of captured methane for gas treatment and pipeline injection.

MMC projects would be located on active mines and existing abandoned mine sites that are located primarily in rural areas and are therefore not likely to be located at any of the following: 1) within one-quarter mile of an existing or proposed school; 2) on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5; 3) within an airport land use plan or within two miles of a public airport; or 4) within the vicinity of a private airstrip. SMCRA regulations include specific performance standards and siting criteria that establish buffering requirements for adjacent land uses. An MMC project would therefore not present a significant safety hazard for people at such locations. Because MMC projects would be located at active mines and existing abandoned mines, implementation of the MMC Protocol would not be anticipated to impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan.

An MMC project may utilize a flare as an end-use management option for destruction of captured mine methane gas. Such a device would require a permit from MSHA which would take into consideration the safety of employing a flare at the project site. Operators of the flare would be required to provide adequate fire suppression and water supply pressure consistent with applicable requirements.

Impacts related to hazards and hazardous materials would, therefore, be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

j) Hydrology and Water Quality

i. Impacts Analysis

Construction Activities:

Hydrology

Some projects may drill new methane drainage wells and boreholes for the purpose of gas extraction when implementing the MMC Protocol. Drilling and well development can result in the removal of significant amounts of groundwater resulting from drawdown of water in the coalbed. This groundwater depletion could eventually impact adjacent shallow aquifers and surface waters (Keith et al. 2003). How these wells are regulated would depend chiefly on land ownership and the state in which the well is located.

As of 2012, 43 percent of all coal produced in the United States originated from public lands (Goad et al. 2012). Any drilling activity on a mine located on federally owned land which would result in an amendment to the federal mining permit would be subject to the conditions of the NEPA. NEPA requires that the federal agency analyze the potential environmental consequences of any major federal action including the preparation of an Environmental Assessment (NEPA EA) or a more detailed Environmental Impact Statement. The level of environmental review required by NEPA is dependent on the extent of the impacts of the proposed action, however recent NEPA EAs have been prepared for federal permit modifications to allow methane capture for mines in Colorado and Pennsylvania. This environmental review would include consideration of potential impacts to groundwater resources.

Well development on both public and private land would be subject to the water rights regulations of the State in which the well is located. The states of Montana, Wyoming, and Colorado have developed specific water-rights regulations related to coalbed methane produced water, detailing such things as the allowable amount of drawdown in aquifers adjacent to the proposed well or requirements for mitigation agreements with effected water-rights holders (NRC 2013). How each state regulates wells drilled for methane capture depends primarily on whether produced water is categorized as a "beneficial use" or as a waste product within the state. If the state classifies produced water as a "beneficial use" the methane capture well would be subject to a water-right allocation. In this case, the state could not grant the allocation without ensuring the protection of adjacent water rights. If classified as a waste product, produced water could not be put to "beneficial use" unless the owner of the water approves. In this case, a well drilled for the purposes of methane capture would not be subject to water rights regulation but would be overseen by the state's division of environmental quality or a similar governing body (NRC 2013).

Well drilling activities would be covered by existing federal or state mining permits or state water rights allocations, or would require the advance acquisition of such permits. In addition, wells drilled for methane capture on federally owned lands would require amending the federal mining permit and could trigger additional environmental review. Finally, in states where methane capture wells would not require water right allocations, the potential for depletion of groundwater would be overseen by the state's division of environmental quality

or a similar governing body. This regulatory structure would ensure that adequate measures are in place to prevent adverse impacts to hydrology and the quantity of groundwater.

Water Quality

The groundwater extracted during drilling, known as produced water, can contain high levels of salts, hydrocarbons, organic and inorganic chemical compounds and naturally occurring radioactive material (NETL 2013). Produced water must be treated and disposed of properly or risk contamination of soils or surface waters. Common disposal methods include evaporation, re-injection, discharge to surface water, and repurposing for beneficial use. The following federal regulations protect surface and groundwater from point-source pollution resulting from disposal of produced water.

- The Safe Drinking Water Act of 1974 (SDWA) established the Underground Injections Control (UIC) program which protects potential sources of drinking water from contamination through underground injection. The strong protections of the UIC program establish performance criteria, require integrity testing of the injection well, monitoring, and annual reporting (EPA 2001).

- The Clean Water Act of 1977 (CWA) requires a National Pollutant Discharge Elimination System (NPDES) permit (and associated environmental review) for any discharge to regulated waters of the United States. The NPDES permit specifies an acceptable level of pollutant or a pollutant parameter within a discharge. This program may also set non-degradation standards for surface waters.

These federal regulations provide protections to surface and groundwater resources and greatly reduce the potential for contamination resulting from the disposal of produced water. In addition, all MMC projects would be required to comply with existing state and local regulations governing the disposal of produced water.

The specific design details and siting locations for new wells and well pads are not known at this time. New drill pads would vary in size from ¼ to ½ acre and would be likely to generate greater run-off compared to undisturbed sites. However, Offset Project Operators would be required to implement MMC projects in accordance with all federal, state and local erosion, drainage, and water quality requirements. These requirements would ensure that adequate measures would be in place to prevent adverse water quality impacts.

Operational Activities:

Operation of a methane drainage well would continue to create produced water. As described above, this water can contain contaminants and requires treatment or disposal in accordance with the provisions of the CWA and SDWA, as well as

any applicable State and local regulations. If gas treatment takes place at a mine as part of an MMC project, it would likely rely upon groundwater supplies. Access to groundwater would be regulated by the states' water rights allocation programs or overseen by the division of environmental quality or a similar governing body. This regulatory structure would ensure that adequate measures are in place to prevent adverse impacts to hydrology and water quality. Gas treatment activities may also result in waste which must be discharged in a fashion compliant with applicable waste discharge requirements per the Protocol's requirement that Offset Project Operators comply with all federal, state, and local laws and regulations.

Gas transport, gas destruction and methane destruction monitoring would result in no impacts to hydrology and water quality.

It is unlikely that MMC projects would result in any of the following: 1) the alteration of an existing drainage pattern; 2) create or contribute runoff water which would exceed the capacity of existing or planned storm-water drainage systems or provide substantial additional sources of polluted runoff; 3) the placement of a structure within a 100-year flood hazard that would impeded or redirect flood flows; 4) expose people or structures to a significant risk involving flooding; or 5) the inundation by seiche, tsunami, or mudflow.

All projects implemented under the MMC Protocol must be in accordance with all applicable federal, state, and local regulations and regulatory oversight requirements in order to be issued credits for emission reductions. Consequently, the potential impacts to hydrology and water quality would likely not be adverse, and where an adverse impact may occur, would be less than significant due to the required compliance with laws and regulations.

ii. Mitigation Measures

Mitigation is not warranted.

k) Land Use and Planning

i. Impacts Analysis

The installation of mine methane gas extraction, capture, transportation, treatment, destruction, and monitoring equipment would be situated at either active or abandoned mines throughout the United States. For the most part, such projects would be located in rural areas on land designated for mining in applicable federal, state or local land use or natural resource management plans. Mine methane management can be considered an integral part of mine operations and therefore would not result in land use conflicts at active mines.

In some circumstances, MMC offset projects located at abandoned mines could be located within or adjacent to areas where reclamation has occurred subsequent to a mine's closure and abandonment, pursuant to the SMCRA. Mine reclamation activities

such as re-vegetation, reforestation, and geomorphological restoration on abandoned mine lands can also eventually lead to restored public use. Other "higher or better" land uses may also be permitted subject to completion of reclamation activities. Because specific offset projects at abandoned mines have not yet been identified, however, the degree to which reclaimed or other new land uses at or adjacent to abandoned mines could be affected remains uncertain.

Any MMC compliance response activities at abandoned mining sites would be required to comply with federal, state and local permitting requirements under SMCRA or applicable land use and zoning regulations that are in effect subsequent to completion of reclamation activities, in order to avoid potential land use conflicts on abandoned mining lands. Thus, any potential adverse effects related to MMC projects at abandoned mines with respect to applicable land use policies and regulations would be minimized. No conflicts with land use plans, policies or physical division of existing communities would be expected occur as a result of the MMC Protocol.

Impacts related to land use and planning would, therefore, be considered less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

l) Noise

i. Impacts Analysis

Construction Activities:

All MMC projects would involve construction activities related to the installation of mine methane gas extraction, capture, transportation, treatment, destruction and monitoring equipment and related infrastructure, such as gathering lines. Construction activities would involve the use of heavy off-road equipment, as well as trucks and passenger vehicles to transport materials and construction workers to and from construction sites. These activities would be expected to occur at both active and abandoned mines.

The drilling of new methane drainage wells for the purpose of methane extraction would involve the most extensive construction activities of an MMC project. Construction noise levels in the vicinity of the mine during the well drilling process would depend largely on the phase of construction as well as the particular type, number and duration of usage for the varying equipment. Additionally, construction activities could result in varying degrees of temporary ground-borne noise and vibration, depending on the specific construction equipment used and activities involved. The construction phase of project implementation would last approximately 3 – 12 months per project.

Operational Activities:

Implementation of MMC offset projects could introduce new on-site stationary noise sources (e.g., compressors, flares, oxidizers, and other equipment). Noise levels associated with these types of sources vary greatly, but would likely not surpass the noise levels associated with active mining activities. Noise from the operation of new stationary sources would not substantially increase the ambient noise level at an active mine site. However, operational noise from new on-site stationary sources at abandoned mines could increase ambient noise levels at abandoned mine site and surrounding areas.

The potential effects of noise depend on the distance to noise sensitive receptors, the time of day and duration of activity, the type of equipment to be used in construction and operations, and the existing ambient noise environment in the receptor's vicinity. Because specific MMC offset projects have not been proposed and associated details as to location, size and extent of associated compliance response activities are unknown, precise noise levels cannot be estimated. Noise from compliance response activities would be similar to and consistent with the noise from activities generated by active mining operations.

Offset Project Operators at active mines would be required to comply with any existing federal, state and local noise codes applicable to the jurisdiction including occupational noise exposure standards promulgated by the MSHA. Given that both active and abandoned mine locations are generally located in rural areas and are often isolated, it is not expected that noise generated by MMC projects would be within close enough proximity to noise-sensitive receptors to result in a substantially adverse effect. MMC offset projects located at abandoned mines would be required to comply with any noise abatement provisions in SMCRA regulations and permitting requirements through OSMRE, or any applicable federal, state or local noise codes or ordinances.

Noise related impacts would, therefore, be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

m) Population and Housing

i. Impacts Analysis

The installation of mine methane gas extraction, capture, transportation, treatment, destruction, and monitoring equipment would be located at active or abandoned mining site in rural locations. No existing homes or population would be displaced as a result of these compliance response activities. The construction phase of MMC project implementation would typically require small crews (approximately 5-10 people per project) for a temporary period of time (typically 3-12 months per project). Operation of an MMC project would require minimal (if any) new additional personnel at mines. Proposed MMC offset projects would not be concentrated in any one area but would rather be located at mines throughout the United States. Given the anticipated dispersion of project locations and the limited number of new employment opportunities

associated with the construction and operation of the MMC projects, the number of workers migrating to a project area would be minimal, and therefore no adverse impacts to employment, population and housing are expected.

It is also unlikely that new roads would be built as a result of MMC project implementation since in most cases adequate, although potentially seasonal, access to mine sites exists. If road extension is required on or near a mine site as a result of MMC project implementation, it is still unlikely that it would result in population growth in the area as it would be located at or adjacent to existing mining operations. Therefore, it is expected that MMC offset project impacts related to employment, population and housing would be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

n) Public Services

i. Impacts Analysis

Implementation of an MMC project would not result in additional housing or other facilities that would increase demand for public services including fire and police protection, schools, parks, and other public facilities. There are no impacts to public services.

ii. Mitigation Measures

Mitigation is not warranted.

o) Recreation

i. Impacts Analysis

MMC offset projects would be located at both active mines and existing abandoned mine sites. MMC offset projects at active mines would not be expected to have any substantial effect on the use of existing neighborhood or regional parks or other recreational facilities, since such parks and facilities are not typically located within active mining areas. However, MMC offset projects could be located at abandoned mines where reclamation or restoration activities are underway or planned pursuant to SMCRA, which could potentially affect recreational uses on reclaimed mining lands. In some cases, restoration of natural resources at abandoned mines through reforestation or other activities could result in recreation amenities accessible to the public.

Because specific MMC offset projects have not been proposed and associated details as to location, size and extent of associated compliance response activities are unknown, the extent of potential impacts to recreation facilities or uses at abandoned mines is uncertain. In the event that MMC offset projects would be located at abandoned mines where recreation activities are included as permitted uses under an approved mine reclamation plan, any such activities would be required to comply with

federal and state permitting requirements under SMCRA through OSMRE or other state agencies with permitting authority. Such permitting requirements would ensure that any potential conflicts with recreation activities under an approved reclamation plan would be minimized. Therefore, any potential impacts related to recreation would be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

p) Transportation and Traffic

i. Impacts Analysis

Construction Activities:

An MMC project requiring construction would likely result in a minimal amount of short-term construction traffic (primarily motorized) from the transport of heavy off-road equipment, and worker commute- and material delivery-related trips to active or abandoned mines. The amount of construction activity would fluctuate depending on the particular type, number, and duration of usage for the varying equipment, and the phase of construction (e.g., site preparation, well drilling, well completion). Due to the isolated location of active or abandoned mines in rural settings where MMC offset projects would be located, it is unlikely that implementation would conflict with applicable transportation programs, plans, ordinances, or policies (e.g., performance standards, congestion management).

If any construction traffic control plans or measures, such as temporary roadway closures or detours, would be required in order to construct an MMC project at an active or abandoned mine, compliance with the appropriate federal, state or local transportation agencies would be required. Any hazardous design features and emergency access issues from road closures, detours, and obstruction of emergency vehicle movement would be minimized.

Operational Activities:

With respect to operational-related activities, minimal (if any) additional personnel would be needed to operate typical MMC projects at active mining operations. Similarly, MMC projects at abandoned mines would require minimal personnel on-site to monitor the performance of MMC equipment, once the construction phase is completed. Consequently, these projects would not be expected to result in substantial traffic volumes on local roadways. Thus, implementation of the MMC Protocol would not generate long-term operational traffic that conflicts with applicable programs, plans, ordinances, or policies; result in a change in air traffic patterns; substantially increase hazards due to design features; or result in inadequate emergency access. Impacts on transportation and traffic would, therefore, be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

q) Utilities and Service Systems

i. Impacts Analysis

MMC projects could result in an increase in demand on utilities and/or service systems that serve typical mining operations, due to the need for additional electricity, natural gas, water supply, and treatment and disposal of wastewater to support construction and operation of the MMC project at active mining sites. Similarly, increased demands on utilities and service systems could be required at abandoned mining sites. In some cases, however, operations of MMC projects could result in a net increase in the available supply of energy at active mining sites where mine methane gas would be converted through gas treatment activities, or injected into local pipelines, resulting in beneficial effects to energy supplies and local utilities.

The capacity of localized or regional utilities and service systems that serve all potential active or abandoned mines where MMC projects could occur is unknown, however any increased demands would not be expected to exceed the capacity of local service providers or result in adverse environmental impacts due solely to the installation of MMC offset projects. Any increased demand would be relatively small and contained, would be additive to existing mining operations, and would not be concentrated in any one area such that they would result in a substantial demand for utilities and service systems (e.g., solid waste facilities capacity, electricity, natural gas, wastewater services, water demand and supply services, wastewater treatment requirements, and solid waste regulations) above and beyond what could be provided by existing service providers and resources.

Impacts to utilities and service systems would, therefore, be less than significant.

ii. Mitigation Measures

Mitigation is not warranted.

r) Summary of Impacts and Mitigation Measures

i. Summary Impact Matrix for the MMC Protocol

Potential Impact	Significance Before Mitigation	Potential Mitigation	Significance After Mitigation
Aesthetics			
Result in adverse change to scenic vistas and resources or visual character and quality, light and	Less than significant	Mitigation is not warranted	Less than significant

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glare			
Agriculture and Forest Resources			
Convert agricultural or forest land; conflict with existing zoning uses	Less than significant	Mitigation is not warranted	Less than significant
Air Quality			
Substantially contribute to air quality violation; conflict with air quality plan; contribute to net increase in criteria pollutant deemed to be in non-attainment under AAQS	Less than significant	Mitigation is not warranted	Less than significant
Biological Resources			
Result in adverse impact to species with special status, migratory patterns, riparian habitats or federally protected wetlands; conflict with local protective policies or conservation plans	Potentially significant	Mitigation is warranted The following mitigation applies to address potentially significant biological resources impacts: • Preparation of a biological inventory of site resources by a qualified biologist prior to ground disturbance or construction. If protected species or their habitats are present, comply with applicable federal and state endangered species acts and regulations. Ensure that important fish or wildlife movement corridors or nursery sites are not impeded by project activities. • Preparation of a wetland survey of onsite resources. Establish setbacks and prohibit disturbance of riparian habitats, streams, intermittent and ephemeral drainages, and other wetlands. Wetland delineation is	Significant and Unavoidable

		required by Section 3030(d) of the Clean Water Act administered by the U.S. Army Corps of Engineers. • Prohibit construction activities during the rainy season with requirements for seasonal weatherization and implementation of erosion prevention practices. • Prohibit construction activities in the vicinity of special status nests, dens, burrows or roosts during nesting season or establish protective buffers and provide monitoring as needed to ensure that project activity does not cause an active nest to fail. • Preparation of site design and development plans that avoid or minimize disturbance of habitat and wildlife resources, and prevents stormwater discharge that could contribute to sedimentation and degradation of local waterways. Depending on disturbance size and location, a National Pollution Discharge Elimination System (NPDES) construction permit may be required from the appropriate state or local enforcement authority under the CWA. • Plant replacement trees and establish permanently protection suitable habitat at ratios considered acceptable to comply with local requirements, if necessary.	
Cultural Resources			
Result in adverse impact to the significance of a historical or archaeological	Potentially significant	Mitigation is warranted The following mitigation applies to address potentially significant cultural resources impacts:	Significant and Unavoidable

resource; destroy of paleontological resources; disturb human remains		• Retain the services of cultural resources specialists with training and background that conforms to the U.S. Secretary of Interior's Professional Qualifications Standards, as published in Title 36, Code of Federal Regulations, part 61 (36 CFR Part 61). • Seek guidance from the State Historic Preservation Officer and federal lead agencies, as appropriate, for coordination of Nation-to-Nation consultations with the Native American tribes. • Proponents of the MMC offset projects shall consult with lead agencies early in the planning process to identify the potential presence of cultural properties. The agencies shall provide the project developers with specific instruction on policies for compliance with the various laws and regulations governing cultural resources management, including coordination with regulatory agencies and Native American Tribes. • Proponents of the MMC offset projects shall define the area of potential effect (APE) for each project, which is the area within which project construction and operation may directly or indirectly cause alterations in the character or use of historic properties. The APE shall include a reasonable construction buffer zone and laydown areas, access roads, and borrow areas, as well as a reasonable assessment of areas subject to effects from visual, auditory, or atmospheric	

		impacts, or impacts from increased access. • Proponents of the MMC offset projects shall retain the services of a paleontological resources specialist with training and background that conforms with the minimum qualifications for a vertebrate paleontologist as described in Measures for Assessment and Mitigation of Adverse Impacts to Non-Renewable Paleontologic Resources: Standard Procedures, Society of Vertebrate Paleontology, 1995 http://www.vertpaleo.org/society/polstateconfomimpactmigig.cfm. • Proponents of the MMC offset projects shall conduct initial scoping assessments to determine whether proposed construction activities, if any, could disturb formations that may contain important paleontological resources. Whenever possible potential impacts to paleontological resources should be avoided by moving the site of construction or removing or reducing the need for surface disturbance. The scoping assessment shall be conducted by the qualified paleontological resources specialist in accordance with applicable agency requirements. • The project proponent's qualified paleontological resources specialist shall determine whether paleontological resources would likely be disturbed in a project area on the basis of the sedimentary context of the area and a records search for past	

		paleontological finds in the area. The assessment may suggest areas of high known potential for containing resources. If the assessment is inconclusive a surface survey is recommended to determine the fossilferous potential and extent of the pertinent sedimentary units within the project site. If the site contains areas of high potential for significant paleontological resources and avoidance is not possible, prepare a paleontological resources management and mitigation plan that addresses the following steps: a) a preliminary survey (if not conducted earlier) and surface salvage prior to construction; b) physical and administrative protective measures and protocols such as halting work, to be implemented in the event of fossil discoveries; c) monitoring and salvage during excavation; d) specimen preparation; e) identification, cataloging, curation and storage; and f) a final report of the findings and their significance. g) Choose sites that avoid areas of special scientific value.	
Energy Demand			
Increase energy demand, conflict with energy plans	Less than significant	Mitigation is not warranted	Less than significant
Geology, Soils and Minerals			
Expose people or structures to rupture of a known	Less than significant	Mitigation is not warranted	Less than significant

earthquake fault, ground shaking or failure, or landslide; substantial soil erosion; location on an unstable geologic unit or soil			
Greenhouse Gas Emissions			
None	No adverse impact	Mitigation is not warranted	No adverse impact
Hazards and Hazardous Materials			
Create hazard to the public or environment from routine management or accidental release of hazardous materials	Less than significant	Mitigation is not warranted	Less than significant
Hydrology and Water Quality			
Violate water quality standards or waste discharge requirements; substantially deplete or interfere with recharge of groundwater supplies; alter existing drainage pattern; exceed capacity for runoff water	Less than significant	Mitigation is not warranted	Less than significant
Land Use and Planning			
Physically divide an existing community, conflict with an applicable land use plan, conflict with habitat conservation plan or natural community	Less than significant	Mitigation is not warranted	Less than significant

conservation plan			
Noise			
Generate and expose persons to noise levels in excess of established noise and vibration standards; substantially increase permanent or temporary ambient noise levels	Less than significant	Mitigation is not warranted	Less than significant
Population and Housing			
Induce substantial population growth in an area, either directly or indirectly	Less than significant	Mitigation is not warranted	Less than significant
Public Services			
None	No adverse impact	Mitigation is not warranted	No adverse impact
Recreation			
Adverse impacts to existing recreational facilities	Less than significant	Mitigation is not warranted	Less than significant
Transportation and Traffic			
Conflict with transportation or traffic management plan, ordinance or policy	Less than significant	Mitigation is not warranted	Less than significant
Utilities and Service Systems			
Exceed the capacity of water, wastewater, storm water drainage, or landfill facilities;	Less than significant	Mitigation is not warranted	Less than significant

4. Mandatory Findings of Significance

Consistent with the requirements of the CEQA Guidelines, Appendix G, Environmental Checklist, Section 18, the 2010 FED addressed the mandatory findings of significance as

discussed below. The 2010 FED also included discussions on significant and unavoidable environmental effects and significant and irreversible environmental changes. As with all of the environmental effects and issue areas, the precise nature and magnitude of impacts would depend on the types of projects authorized, their locations, their aerial extent, and a variety of site-specific factors that are not known at this time but that would be addressed by environmental reviews at the project-specific level. Outside of California, other federal, state and local agencies would consider the proposed projects in accordance with their laws and regulations. ARB would not be the agency responsible for conducting the project-specific environmental or approval reviews because it is not the agency with authority for making land use or project implementation decisions.

The 2010 FED, in its entirety, addressed and disclosed potential environmental effects associated with implementation of California's Cap-and-Trade regulation. As described in the impact analyses for the 2010 FED, as well as in this EA, potential environmental impacts, the level of significance prior to mitigation, mitigation measures, and the level of significance after the incorporation of mitigation measures are disclosed.

a) Does the project have impacts that are individually limited, but cumulatively considerable?

Cumulative impacts were discussed in the 2010 FED and referred to in this in the EA (See Section 5 below).

b) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?

While changes to the environment that could indirectly affect human beings would be represented by all of the designated CEQA issue areas, those that could directly affect human beings include air quality, geology and soils, hazards and hazardous materials, hydrology and water quality, noise, population and housing, public services, transportation/traffic, and utilities, which are all addressed above in this EA. The results of the impact analysis in this EA determined that any impacts in the resource areas would be less than significant, and therefore no substantial adverse impacts would directly affect human beings.

5. Cumulative and Growth-Inducing Impacts

The 2010 FED disclosed cumulative impacts for resource topics in general qualitative terms, recognizing the programmatic nature of the 2010 FED, as they pertain to reasonably foreseeable development. The cumulative impacts are required to be addressed when the cumulative impacts are expected to be significant and when the project's incremental contribution to the effect is cumulatively considerable. Where a lead agency is examining a project with an incremental effect that is not "cumulatively considerable," a lead agency need not consider that effect significant, but must briefly describe its basis for concluding that the incremental effect is not cumulatively

considerable. ARB considered in the 2010 FED the cumulative impacts analysis of other projects that, like Cap-and-Trade, are designed to reduce annual emissions of GHGs, and not simply every project that emits GHGs. This approach is "guided by the standards of practicality and reasonableness" and serves the purposes of the cumulative impacts analysis, which is to provide "a context for considering whether the incremental effects of the project at issue are considerable" when judged "against the backdrop of the environmental effects of other projects." (*CBE v. Cal. Res. Agency* (2002) 103 Cal.App.4th 98, 119).

The level of detail in the cumulative and growth-inducing impacts discussion in the 2010 FED was guided by what is practical and reasonable, and contained the following elements (CARB 2010o):

- An analysis of related future projects or planned development that would affect resources in the project area similar to those affected by the proposed project.

- A summary of the expected environmental effects to be produced by those projects with specific reference to additional information stating where that information is available.

- A reasonable analysis of the cumulative impacts of the relevant projects. An environmental document must examine reasonable feasible options for mitigating or avoiding the project's contribution to any significant cumulative effects.

Due to the reach of California's Cap-and-Trade program and, consequently, also the reach of the Proposed MMC Protocol, the impact analysis is inherently cumulative in nature, rather than site- or project-specific. As a result, the character of impact conclusions in the resource-oriented impact analysis discussions are cumulative, considering the potential effects of the full range of reasonably foreseeable methods of compliance, along with expected background growth in California, as appropriate.

For purposes of the cumulative analysis contained in the 2010 FED, impacts were based on the program's contribution to environmental impacts in combination with the environmental effects of the ongoing, adopted, and reasonably foreseeable Scoping Plan measures, and the State Implementation Plan (SIP), which includes goods movement measures (heavy-duty vehicle efficiency, ship electrification, port drayage truck measures, and vessel speed reduction). The ongoing, adopted, and foreseeable Scoping Plan measures (as numbered in the Scoping Plan) are as follows:

<u>Measures in Capped Sectors</u>

Transportation

T-1 Advanced Clean Cars
T-2 Low Carbon Fuel Standard
T-3 Regional Targets (SB 375)
T-4 Tire Pressure Program

T-5 Ship Electrification
T-7 Heavy Duty Aerodynamics
T-8 Medium/Heavy Hybridization
T-9 High Speed Rail

Electricity and Natural Gas

E-1 Energy Efficiency and Conservation
CR-1 Energy Efficiency and Conservation
CR-2 Solar Hot Water (AB 1470)
E-3 Renewable Electricity Standard (20 percent–33 percent)
E-4 Million Solar Roofs

Industrial Measures

I-1 Energy Efficiency and Co-Benefits Audits for Large Industrial Sources

Measures In Uncapped Sources/Sectors

H-1 Motor Vehicle A/C Refrigerant Emissions
H-2 SF6 Limits on non-utility and non-semiconductor applications
H-3 Reduce Perfluorocarbons in Semiconductor Manufacturing
H-4 Limit High GWP use in Consumer Products
H-6 Refrigerant Tracking/Reporting/Repair Deposit Program
H-6 SF6 Leak Reduction and Recycling in Electrical Applications
F-1 Sustainable Forests
RW-1 Landfill Methane Control Measure

The cumulative impact analysis determined the combined effect of California's Cap-and-Trade regulation and other closely related, reasonably foreseeable projects. The discussion of cumulative impacts need not provide as much detail as the discussion of effects attributable to the program alone. The level of detail in the 2010 FED was guided by what was practical and reasonable.

As disclosed in the 2010 FED, implementation of California's Cap-and-Trade regulation (which assumed the implementation of new offset protocols in addition to what was analyzed in the 2010 FED) was determined to potentially result in cumulatively considerable impacts. While suggested mitigation was provided for each potentially cumulatively considerable impact, the mitigation would need to be implemented by other agencies. Where impacts could not be feasibly mitigated, the 2010 FED recognized the impact as significant and unavoidable. The Board adopted Findings and a Statement of Overriding Considerations. Any potential cumulative impacts from implementation of the proposed MMC Offset Protocol were addressed in the prior 2010 FED, and no further analysis is required.

D. Alternatives

Under ARB's CEQA Certified Regulatory Program (CRP), an EA shall address "feasible alternatives to the proposed action [that] would substantially reduce any significant adverse impact identified" (CCR, Title 17, Section 60005[b]). Additionally, any ARB action or proposal for which significant adverse environmental impacts have been identified shall not be approved or adopted as proposed, if there are "feasible alternatives available [that] would substantially reduce such adverse impact" (CCR, Title 17, Section 60006). CEQA Guidelines, CCR, Title 14, Section 15126.6(a) also indicates the need for an evaluation of "a range of reasonable alternatives to the project, or the location of the project, [that] would feasibly attain most of the basic project objectives but would avoid or substantially lessen any of the significant effects, and evaluate the comparative merits of the alternatives."

The purpose of the alternatives analysis is to determine whether or not a variation of the proposed action would reduce or eliminate significant project impacts, within the framework of achieving the basic project objectives. The proposed action could be designed differently, which provides opportunities to define alternatives for the EA analysis. This section of the chapter describes and analyzes a reasonable range of alternatives that could feasibly avoid or lessen any significant environmental impacts while substantially attaining the basic project objectives.

1. No Project Alternative

   a) Description and Consistency with Project Objectives

   CEQA requires a specific "No Project" alternative to be evaluated. The "No Project" alternative defines a scenario in which ARB would not adopt the MMC Protocol. Under this alternative, California entities could not use carbon offset credits for emission reductions achieved from the installation and operation of a device or set of devices that capture and destroy methane that would otherwise be released into the atmosphere as a result of mining.

   The primary objectives of offsets in the Cap-and-Trade program that are applicable to the proposed MMC Protocol are described above in Section B of this EA. By not implementing the MMC Protocol, none of the primary objectives would be achieved. The supply of offsets to broaden the compliance instrument market would not be expanded, thereby diminishing an opportunity to ensure cost-effective GHG reductions. Potential technological innovations developed through the implementation of MMC technologies and associated projects would not occur, and the potential for additional GHG emissions within the mining sector would not be achieved.

   b) Environmental Impacts

   There would be no significant environmental impacts under the No Project alternative, because no compliance responses would occur. Environmental

benefits resulting from the capture of methane achieved under the proposed project would also not occur.

2. Exclude Abandoned Mines Alternative

a) Description and Consistency with Project Objectives

Another alternative to adopting the proposed MMC Protocol would be to limit the issuance of Air Resources Board Offset Credits (ARBOCs) to the destruction of methane extracted from active surface or underground mines only. Abandoned underground mine methane recovery activities would be excluded.

This alternative would result in fewer ARBOCs being issued than under the proposed project. Because issuance of ARBOCs would still occur for projects at active mining operations, this alternative would be consistent with the stated primary objectives of the project but would not fulfill those objectives to the fullest extent. Excluding abandoned mines could result in a narrower range of potential activities, resulting in a reduced supply of offsets available and therefore a lower potential for program cost effectiveness in the cap-and-trade program. Similarly, eliminating abandoned mines would result in fewer opportunities for technological innovation that could occur as a result of project deployment, and fewer GHG reductions would be achieved under this alternative than under the proposed MMC Protocol. Therefore, while this alternative is conceptually feasible, the primary objectives would not be fully realized.

b) Environmental Impacts

Abandoned mining sites, similar to active mines, are subject to regulation of reclamation activities under SMCRA. This EA identified potentially significant impacts to biological and cultural resources at these sites. Exclusion of abandoned underground mine methane recovery activities would avoid environmental impacts at abandoned mining sites; however, potentially significant biological and cultural resources impacts could still occur at active mining sites in cases where the MMC Protocol would still apply. Environmental effects related to other resource topics would be similar to those described for the proposed MMC Protocol.

3. Surface Equipment Only Alternative

a) Description and Consistency with Project Objectives

Another alternative to the proposed MMC Protocol would be to limit the issuance of ARBOCs to projects that involve the installation of surface equipment for the destruction of mine methane extracted only from (1) existing permitted ventilation

shafts and drainage wells/boreholes currently located at an active or abandoned mine, or (2) new ventilation shafts and drainage wells/boreholes slated to be constructed in a mine plan for currently operating or new mines that are identified as necessary to ongoing or proposed mining activities.

MMC projects requiring construction of entirely new ventilation shafts and drainage wells/boreholes at a new or existing mine for the sole purpose of receiving ARBOC's for mine methane capture and destruction would not receive credit under this alternative; rather, these components must be identified in the mine plan as necessary components to overall mining operations. Therefore, if this alternative were pursued, ventilation shafts and drainage wells/boreholes constructed specifically for the purpose of mine methane capture and destruction, above and beyond those required to meet safety regulations and those previously utilized to extract virgin coal bed methane, would not be deemed eligible methane sources.

Similarly, other compliance response activities, such as construction of gathering pipelines for gas transport, construction of gas treatment facilities, or other activities with the potential for significant excavation, trenching, drilling or other construction methods involving substantial ground disturbance would be excluded under this alternative.

This alternative would substantially reduce the range of potential MMC project compliance responses and, accordingly, the amount of mine methane captured, destroyed, and credited for all four activity types described in the proposed MMC Protocol. Compared to the "No Abandoned Mines" alternative, this alternative could result in substantially fewer ARBOCs being issued and would, therefore, fall short of meeting the primary objectives of achieving the maximum technologically feasible and cost effective GHG emission reductions, encouraging technological innovation in non-capped sectors, and decreasing greenhouse gas emissions.

b) Environmental Impacts

By restricting MMC projects to surface equipment installations connecting with existing or new ventilation or drainage systems as defined above, this alternative would avoid the need for drilling additional wells or boreholes and, therefore, avoid or further reduce potentially significant impacts to biological and cultural resources. Likewise, excluding the possibility of additional drilling, excavation or other substantial ground-disturbing construction activities related to gas extraction, transport, and treatment would avoid and/or further reduce potentially significant impacts to biological and cultural resources. Environmental effects related to other resource topics would be similar to those described for the proposed MMC Protocol.

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California Environmental Protection Agency

AIR RESOURCES BOARD

Proposed Compliance Offset Protocol Mine Methane Capture Projects

Capturing and Destroying Methane From U.S. Coal and Trona Mines

Adopted: [INSERT Date of Board Adoption]

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Chapter 1: Purpose and Definitions

§ 1.1. Purpose.

(a) The purpose of the Compliance Offset Protocol Mine Methane Capture Projects (protocol) is to quantify greenhouse gas (GHG) emission reductions associated with the capture and destruction of methane (CH_4) that would otherwise be vented into the atmosphere as a result of mining operations at active underground and surface coal and trona mines and abandoned underground coal mines.

(b) AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA);[1] however those elements of the protocol are still regulatory. The exemption allows future updates to the quantification methodologies to be made through a public review and Board adoption process but without the need for rulemaking documents. Each protocol identifies sections that are considered quantification methodologies and exempt from APA requirements. Any changes to the non-quantification elements of the offset protocols would be considered a regulatory update subject to the full regulatory development process. Those sections that are considered to be a quantification methodology are clearly indicated in the title of the chapter or subchapter if only a portion of that chapter is considered part of the quantification methodology of the protocol.

§ 1.2. Definitions.

(a) For the purposes of this protocol, the following definitions apply:

(1) "Abandoned Underground Mine" means a mine where all mining activity including mine development and mineral production has ceased, mine personnel are not present in the mine workings, and mine ventilation fans are no longer operative. A mine must be classified by the Mine Safety and Health Administration (MSHA) as abandoned or temporarily idle in order to be eligible for an abandoned mine methane recovery activity.

(2) "Abandoned Mine Methane" or "AMM" means methane released from an abandoned mine.

[1] Health and Safety Code section 38571

(3) "Accuracy" means the closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.

(4) "Active Surface Mine" means a permitted mine in which the mineral lies near the surface and can be extracted by removing the covering layers of rock and soil. A mine must be classified by the Mine Safety and Health Administration (MSHA) as active or intermittent in order to be eligible for an active surface mine methane drainage activity.

(5) "Active Underground Mine" means a permitted mine usually located several hundred feet below the earth's surface. A mine must be classified by the Mine Safety and Health Administration (MSHA) as active or intermittent in order to be eligible for an active underground mine methane drainage or ventilation air methane activity.

(6) "ASTM" means the American Society of Testing and Materials.

(7) "Basin" means geological provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991), which is hereby incorporated by reference.

(8) "Boiler" means a closed vessel or arrangement of vessels and tubes, together with a furnace or other heat source, in which water is heated to produce hot water or steam.

(9) "Borehole" means a hole made with a drill, augur or other tool into a coal seam or surrounding strata from which natural gas is extracted.

(10) "Cap-and-Trade Regulation" or "Regulation" or "Cap-and-Trade Program" means ARB's regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations, Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(11) "Coal" means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388-05 "Standard Classification of Coals by Rank" (2005), which is hereby incorporated by reference.

(12) "Coal Bed Methane" or "CBM" or "Virgin Coal Bed Methane" means methane-rich natural gas drained from coal seams and surrounding strata not disturbed by mining. The extraction, capture, and destruction of virgin coal bed methane are unrelated to mining activities and are not eligible under this protocol.

(13) "Emission Factor" means a unique value for determining an amount of a GHG emitted for a given quantity of activity (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned).

(14) "Enclosed Flare" means a flare that is situated in an enclosure for the purposes of safety and accurate measurement of gas combustion.

(15) "End-use Management Option" means a method of methane destruction deemed either eligible or ineligible for the purpose crediting under this protocol.

(16) "Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

(17) "Flare" means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. For purposes of this protocol, an enclosed flare is considered a flare.

(18) "Flooded Mine" means a mine that is flooded, i.e. filled with water, as a result of the turning off of pumps at time of abandonment and has no detectable freely venting methane emissions. Mines that either pump water due to regulatory or legal requirements or have detectable free standing water shall not be considered flooded provided that they still freely vent methane.

(19) "Flow Meter" means a measurement device consisting of one or more individual components that is designed to measure the bulk fluid

movement of liquid or gas through a piped system at a designated point. Bulk fluid movement can be measured with a variety of devices in units of mass flow or volume.

(20) "Gas Treatment" means applying techniques to extracted mine gas such as dehydration, gas separation, and the removal of non-methane components to prepare the mine gas for an end-use management option, including pipeline injection.

(21) "Gob" means the part of the mine from which the mineral and artificial supports have been removed and the roof allowed to fall in. Gob is also known as "Goaf."

(22) "Greenhouse Gas Assessment Boundary" or "GHG Assessment Boundary" or "Offset Project Boundary" is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

(23) "Longwall" means a method of underground mining where a mechanical shearer is pulled back and forth across a coal face and loosened coal falls onto a conveyor for removal from the mine.

(24) "Methane Drainage System" or "Drainage System" means a system that drains methane from coal or trona seams and/or surrounding rock strata and transports it to a common collection point. Methane drainage systems may comprise multiple methane sources.

(25) "Methane Source" means a methane source type (i.e., ventilation shafts, pre-mining surface wells, pre-mining in-mine boreholes, post-mining gob wells, existing coal bed methane wells that would otherwise be shut-in and abandoned, abandoned wells that are re-activated, and converted dewatering wells) in the aggregate. In this protocol, "methane source" does not refer to any specific ventilation shaft, borehole, or well, but

instead refers to all the ventilation shafts, boreholes, and wells of the same type collectively.

(26) "Mine Gas" or "MG" means the untreated gas extracted from within a mine through a methane drainage system that often contains various levels of other components (e.g. nitrogen, oxygen, carbon dioxide, hydrogen sulfide, NMHC, etc.).

(27) "Mine Methane" or "MM" means methane contained in mineral deposits and surrounding strata that is released as a result of mining operations; the methane portion of mine gas.

(28) "Mine Operator" means 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. For purposes of this protocol, the Mine Operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

(29) "Mine Safety and Health Administration" or "MSHA" means the U.S. federal agency that regulates mine health and safety.

(30) "Mining Activities" means working an area, or panel, of coal or trona that has been developed and equipped to facilitate mineral extraction and is shown on a mining plan.

(31) "Mountaintop Removal Mining" means a method of surface mining involving the removal of the covering layers of rock and soil at or near the top of a mountain to expose coal seams. Projects which occur at mines that employ mountaintop removal mining are not eligible under this protocol.

(32) "Natural Gas Pipeline" or "Pipeline" means a high pressure pipeline transporting saleable quality natural gas offsite to distribution, metering or regulating stations or directly to customers.

(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 or used to combust mine methane via an ineligible

end-use management option per section 3.4. Methane destroyed by a non-qualifying device must be monitored for quantification of both the baseline and project scenarios.

(34) "Offset Project Expansion" means the addition of a new methane source or new destruction device to an existing MMC project. A methane source is deemed new if it is either drilled after offset project commencement or connected to a destruction device after offset project commencement. A destruction device is deemed new if it becomes operational after offset project commencement. Under certain circumstances, described in Chapter 2, the addition of new methane sources or new destruction devices may qualify as a new MMC project or an offset project expansion. In those cases, an Offset Project Operator may choose how to define the addition. Offset project expansion, unlike the establishment of a new MMC project, will not result in a new offset project commencement date or crediting period. Offset project expansion, unlike the establishment of a new MMC project, allows the Offset Project Operator to submit a single annual Offset Project Data Report (OPDR) and undergo a single annual verification.

(35) "Open-pit" means a method of surface mining where coal is exposed by removing the overlying rock. This is also known as open-cut or opencast mining.

(36) "Oxidation" means a reaction in which the atoms in an element lose electrons and the valence of the element is correspondingly increased. An example of an oxidation reaction is the combustion of CH_4 in air to form CO_2 and water.

(37) "Pre-mining In-mine Boreholes" means a borehole drilled into an unmined seam from within the mine to drain methane from the seam ahead of the advancement of mining. This is also known as horizontal pre-mining boreholes.

(38) "Pre-mining Surface Wells" means a well drilled into an unmined seam from the surface to drain methane from the seam and surrounding strata,

often months or years in advance of mining. This is also known as surface pre-mining boreholes, surface-to-seam boreholes, and surface-drilled directional boreholes.

(39) "Post-mining Gob Well" or "Gob Well" means a well used to extract or vent methane from the gob. Gob wells may be drilled from the surface or within the mine.

(40) "Project Activity" means a change in mine methane management that leads to a reduction in GHG emissions in comparison to the baseline management and GHG emissions.

(41) "Qualifying Destruction Device" or "Qualifying Device" means a destruction device that was not operational at the mine prior to offset project commencement and that was not used to combust mine methane via an ineligible end-use management option per section 3.4. Methane destructed by a non-qualifying device must be monitored for quantification of both the baseline and project scenarios.

(42) "Room and Pillar" means a method of underground mining in which approximately half of the coal is left in place as "pillars" to support the roof of the active mining area while "rooms" of coal are extracted.

(43) "Sealed," in reference to an abandoned mine, means any entrance into the mine (e.g., portals, ventilation shafts, methane drainage wells) has been sealed. The volume of methane trapped in the mine and the rate at which mine gas is emitted from the mine is dependent on the effectiveness of the sealing.

(44) "Shut-in" means to close, temporarily, a well capable of production.

(45) "Standard Conditions" or "Standard Temperature and Pressure" or "STP" means 60 degrees Fahrenheit and 14.7 pounds per square in absolute.

(46) "Standard Cubic Foot" or "scf" is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and 14.7 pounds per square inch (1 atm) of pressure.

(47) "Strata", plural of stratum, means the layers of sedimentary rock surrounding a coal seam.

(48) "Surface Mine Methane" or "SMM" means methane contained in mineral deposits and surrounding strata that is released as a result of surface mining operations.

(49) "Thermal Energy" means the thermal output produced by a combustion source used directly as part of a manufacturing process, industrial/commercial process, or heating/cooling application, but not used to produce electricity.

(50) "Trona" means a water-bearing sodium carbonate compound mineral that is mined and processed into soda ash or bicarbonate of soda.

(51) "Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

(52) "Uncertainty Deduction" means an adjustment applied to the emission reductions achieved by an abandoned mine methane recovery activity to account for uncertainty related to the use of emission rate decline curves. The purpose of an uncertainty deduction is to ensure that credited emission reductions remain conservative.

(53) "Vented Emissions" means, for purposes of this protocol, intentional or designed releases of CH_4 containing natural gas or hydrocarbon gases through mine ventilation and methane drainage systems.

(54) "Ventilation Air Methane" or "VAM" means methane contained in exhaust air of the ventilation system of a mine, which originates across the mine workings and is diluted to low concentrations by the circulation of outside air.

(55) "Ventilation Air Methane Collection System" or "VAM Collection System" means a system that captures the ventilation air methane from the ventilation system.

(56) "Ventilation Shaft" means a vertical passage used to move fresh air underground and/or to remove methane and other gases from an underground mine.

(57) "Ventilation System" means a system of fans that provides a flow of air to underground workings of a mine for the purpose of sufficiently diluting and removing methane and other noxious gases.

(58) "Venting," in reference to an abandoned mine, means that existing wells and ventilation shafts are left unsealed, allowing air into the mine and methane to escape freely to the atmosphere.

(59) "Well" means a well drilled for extraction of natural gas from a coal seam, surrounding strata, or mine.

(b) For terms not defined in section 1.2(a), the definitions in section 95802 of the Regulation apply.

(c) Acronyms. For purposes of this protocol, the following acronyms apply:

(1) "AAPG" means American Association of Petroleum Geologists.

(2) "AB 32" means Assembly Bill 32, the Global Warming Solutions Act of 2006.

(3) "AMM" means abandoned mine methane.

(4) "APA" means Administrative Procedure Act.

(5) "APD" means Authorized Project Designee.

(6) "ARB" means the California Air Resources Board.

(7) "atm" means atmosphere in reference to a unit of pressure.

(8) "BAU" means business as usual.

(9) "Btu" means British thermal unit.

(10) "CBM" means coal bed methane.

(11) "CH_4" means methane.

(12) "CO_2" means carbon dioxide.

(13) "CO_2e" means carbon dioxide equivalent.

(14) "F" means Fahrenheit.

(15) "GHG" means greenhouse gas.

(16) "GWP" means global warming potential.

(17) "kg" means kilogram.

(18) "lb" means pound.

(19) "m" means minute.

(20) "MG" means mine gas.

(21) "MM" means mine methane.

(22) "MMBtu" means million British thermal units.

(23) "MMC" means mine methane capture.

(24) "MRR" means Mandatory Reporting Regulation; the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(25) "Mscf" means thousand standard cubic feet.

(26) "MSHA" means Mine Safety and Health Administration.

(27) "MWh" means megawatt hour.

(28) "N_2O" means nitrous oxide.

(29) "OPDR" means Offset Project Development Report.

(30) "OPO" means Offset Project Operator.

(31) "R" means Rankine.

(32) "scf" means standard cubic foot.

(33) "scf/d" means standard cubic feet per day.

(34) "scfm" means standard cubic feet per minute.

(35) "SMM" mean surface mine methane.

(36) "SSR" means GHG sources, sinks, and reservoirs.

(37) "STP" means standard temperature and pressure.

(38) "t" means metric ton.

(39) "QA/QC" means quality assurance and quality control.

(40) "VAM" means ventilation air methane.

Chapter 2: Eligible Activities – Quantification Methodology

This protocol includes four mine methane capture activities designed to reduce GHG emissions that result from the mining process at active underground mines, active surface mines, and abandoned underground mines. The following types of mine methane capture activities are eligible:

§ 2.1. Active Underground Mine Ventilation Air Methane Activities.

This protocol applies to MMC projects that install a ventilation air methane (VAM) collection system and qualifying device to destroy the methane in VAM otherwise

vented into the atmosphere through the return air shaft(s) as a result of underground coal or trona mining operations.

(a) Methane source eligible for VAM activities include:

1) Ventilation shafts
2) Methane drainage systems from which mine gas is extracted and used to supplement VAM. Only the mine methane sent with ventilation air to a destruction device is eligible.

(b) In order to be considered a qualifying device for the purpose of this protocol, the device must not be operating at the mine prior to offset project commencement.

(c) At active underground mines, an Offset Project Operator or Authorized Project Designee may operate both VAM and methane drainage activities as a single offset project all sharing the earliest commencement date. Alternatively, the Offset Project Operator or Authorized Project Designee may elect to operate separate offset projects for each activity with unique commencement dates.

(d) If a newly constructed ventilation shaft is connected to an existing or new destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(e) If an existing ventilation shaft that was not connected to a destruction device at time of offset project commencement is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(f) If a new qualifying destruction device is added to a ventilation shaft currently connected to an existing qualifying destruction device this addition of the new destruction device is considered an offset project expansion.

(g) Ventilation air methane from any ventilation shaft connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

§ 2.2. Active Underground Mine Methane Drainage Activities.

This protocol applies to MMC projects that install equipment to capture and destroy methane extracted through a methane drainage system that would otherwise be vented into the atmosphere as a result of underground coal or trona mining operations.

(a) Methane drainage systems must consist of one, or a combination of, the following methane sources that drain methane from the mineral seam, surrounding strata, or underground workings of the mine before, during, and/or after mining:

(1) pre-mining surface wells;

(2) pre-mining in-mine boreholes; and

(3) post-mining gob wells.

(b) In order to be considered a qualifying device for the purpose of this protocol, a methane destruction device for an active underground mine methane drainage activity must not be operating at the mine prior to offset project commencement and must represent an end-use management option other than natural gas pipeline injection.

(c) At active underground mines, an Offset Project Operator or Authorized Project Designee may operate both VAM and methane drainage activities as a single project all sharing the earliest commencement date. Alternatively, the Offset Project Operator or Authorized Project Designee may elect to operate separate projects for each activity with unique commencement dates.

(d) If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(e) If an existing well/borehole that was not connected to a destruction device at time of offset project commencement is connected to an existing or new destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(f) If a new qualifying destruction device is connected to a well/borehole currently connected to an existing qualifying destruction device, this addition of the new destruction device is considered an offset project expansion.

(g) Mine methane from any well or borehole connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

(h) Active underground mines with MMC projects must not:

(1) account for virgin coal bed methane (CBM) extracted from coal seams outside the extents of the mine according to the mine plan or from outside the methane source boundaries as described in section 3.5; or

(2) use CO_2, steam, or any other fluid/gas to enhance mine methane drainage.

§ 2.3. Active Surface Mine Methane Drainage Activities.

This protocol applies to MMC projects that install equipment to capture and destroy methane extracted through a methane drainage system that would otherwise be vented into the atmosphere as a result of surface coal or trona mining operations.

(a) Methane drainage systems must consist of one, or a combination, of the following methane sources that drain methane from the coal seam or surrounding strata before and/or during mining:

(1) pre-mining surface wells;

(2) pre-mining in-mine boreholes;

(3) existing coal bed methane (CBM) wells that would otherwise be shut-in and abandoned as a result of encroaching mining;

(4) abandoned wells that are re-activated; and

(5) converted dewatering wells.

(b) 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 be operating at the mine prior to offset project commencement.

(c) If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project

Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(d) If an existing well/borehole that was not connected to a destruction device at time of offset project commencement is connected to an existing or new destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(e) If a new qualifying destruction device is connected to a well/borehole currently connected to an existing qualifying destruction device, this addition of the new destruction device is considered an offset project expansion.

(f) SMM from any well or borehole connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

(g) To be eligible for crediting under this protocol, MMC projects at active surface mines must not:

(1) account for virgin CBM extracted from wells outside the extents of the mine according to the mine plan or from outside the methane source boundaries as described in section 3.5; or

(2) use CO_2, steam, or any other fluid/gas to enhance mine methane drainage; or

(3) occur at mines that employ mountaintop removal mining methods.

§ 2.4. Abandoned Underground Mine Methane Recovery Activities.

This protocol applies to MMC projects that install equipment to capture and destroy methane extracted through a methane drainage system that would otherwise be vented into the atmosphere as a result of previous underground coal mining operations.

(a) Methane drainage systems must consist of one, or a combination of, the following methane sources:

(1) pre-mining surface wells, pre-mining in-mine boreholes, or post-mining gob wells drilled into the mine during active mining operations; and

(2) newly drilled surface wells.

(b) In order to be considered a qualifying device for the purpose of this protocol, a methane destruction device for an abandoned underground mine methane recovery activity must not be operating at the mine prior to offset project commencement.

(c) Abandoned underground mine methane recovery activities at multiple mines with multiple mine operators may report and verify together as a single project per the requirements of section 95977 of the Regulation if they meet the following criteria:

(1) A single Offset Project Operator is identified and emission reductions achieved by the project will be credited to that Offset Project Operator.

(2) The methane recovered from the mines is metered at a centralized point prior to being sent to a destruction device.

(3) The Offset Project Operator meets all monitoring, reporting and verification requirements in Chapters 6, 7, and 8.

(4) Offset projects at all mines are in compliance with regulations per section 3.8. If any mine is found to be out of compliance, no emission reductions will be credited to the project even if achieved by one of the other mines found to be in compliance.

(d) In the event that there are vertically separated mines overlying and underlying other mines, wells completed in one mine can be used to capture methane in overlying or underlying mines provided the wells are within the maximum vertical extent of each mine per section 3.5(d)(4).

(e) If a newly drilled well/borehole is connected to an existing or new qualifying destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(f) If an existing well/borehole that was not connected to a destruction device at time of offset project commencement is connected to an existing or new destruction device after offset project commencement, the Offset Project Operator may either classify it as an offset project expansion or register the addition as a new MMC project.

(g) If a new qualifying destruction device is connected to a well/borehole currently connected to an existing qualifying destruction device, this addition of the new destruction device is considered an offset project expansion.

(h) AMM from any well or borehole connected to a non-qualifying destruction device at any point during the year prior to offset project commencement is not eligible for crediting.

(i) To be eligible for crediting under this protocol, MMC projects at abandoned underground mines must not:

(1) account for virgin coal bed methane (CBM) from wells outside the extents of the mine according to the final mine map(s) or from outside the methane source boundaries ascribed in section 3.5; or

(2) use CO_2, steam, or any other fluid/gas to enhance mine methane drainage; or

(3) occur at flooded mines.

Chapter 3. Eligibility

In addition to the offset project eligibility criteria and regulatory program requirements set forth in Subarticle 13 of the Cap-and-Trade Regulation (Regulation), mine methane capture offset projects must adhere to the eligibility requirements below.

§ 3.1. General Eligibility Requirements.

(a) Offset projects that use this protocol must:

(1) involve the installation and operation of a device, or set of devices, associated with the capture and destruction of mine methane;

(2) capture mine methane that would otherwise be emitted to the atmosphere; and

(3) destroy the captured mine methane through an eligible end-use management option per section 3.4.

(b) Offset Project Operators or Authorized Project Designees that use this protocol must:

(1) provide the listing information required by section 95975 of the Regulation and section 7.1;

(2) monitor GHG emission sources within the GHG Assessment Boundary as delineated in Chapter 4 per the requirements of Chapter 6;

(3) quantify GHG emission reductions per Chapter 5;

(4) prepare and submit annual Offset Project Data Reports (OPDRs) that include the information requirements in section 7.2; and

(5) undergo required, independent verification by an ARB-accredited offset verification body in accordance with section 95977 of the Regulation and Chapter 8.

§ 3.2. Location.

(a) Only projects located in the United States are eligible under this protocol.

(b) Offset projects situated on the following categories of land are only eligible under this protocol if they meet the requirements of this protocol and the Regulation, including the waiver of sovereign immunity requirements of section 95975(l) of the Regulation:

1) Land that is owned by, or subject to an ownership or possessory interest of a Tribe;

2) Land that is "Indian lands" of a Tribe, as defined by 25 U.S.C. §81(a)(1); or

3) Land that is owned by any person, entity, or Tribe, within the external borders of such Indian lands.

(c) Projects must take place at either:

1) an active underground or surface mine permitted for coal or trona mining by an appropriate state or federal agency and classified by Mine Safety and Health Administration (MSHA) as an active or intermittent mine; or

2) an abandoned underground coal mine classified as temporarily idle or permanently abandoned by MSHA.

(d) Mines located on federal lands are eligible for implementation of MMC projects.

§ 3.3. Offset Project Operator or Authorized Project Designee.

(a) The Offset Project Operator or Authorized Project Designee is responsible for project listing, monitoring, reporting, and verification.

(b) The Offset Project Operator or Authorized Project Designee must submit the information required by Subarticle 13 of the Regulation and in Chapter 7.

(c) The Offset Project Operator must have legal authority to implement the offset project.

(d) The Offset Project Operator must be a mine operator as defined in section 1.2(a)(28).

§ 3.4. Additionality.

Offset projects must meet the additionality requirements set out in section 95973(a)(2) the Regulation, in addition to the requirements in this protocol. Eligible offsets must be generated by projects that yield surplus GHG reductions that exceed any GHG reductions otherwise required by law or regulation or any GHG reduction that would otherwise occur in a conservative business-as-usual scenario. These requirements are assessed through the Legal Requirement Test in section 3.4.1 and the Performance Standard Evaluation in section 3.4.2.

§ 3.4.1. Legal Requirement Test.

(a) Emission reductions achieved by an MMC project must exceed those required by any law, regulation, or legally binding mandate at the time of offset project commencement.

(b) The following legal requirement test applies to all MMC projects:

(1) 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.

(2) If any 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, only emission reductions resulting from the capture and destruction of mine methane that are in excess of what is required to comply with those laws, regulations, and/or legally binding mandates are eligible for crediting under this protocol.

§ 3.4.2. Performance Standard Evaluation.

(a) Emission reductions achieved by an MMC project must exceed those likely to occur in a conservative business-as-usual scenario.

(b) The performance standard evaluation is satisfied if the following requirements are met, depending on the basis of activity type:

(1) Active Underground Mine VAM Activities

(A) Destruction of VAM via any end-use management option automatically satisfies the performance standard evaluation because destruction of VAM is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this protocol.

(2) Active Underground Mine Methane Drainage 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 automatically satisfies 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 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.

(3) Active Surface Mine Methane Drainage Activities

(A) Destruction of extracted mine methane via any end-use management option 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.

(4) Abandoned Mine Methane Recovery Activities

(A) Destruction of extracted mine methane via any end-use management option automatically meets the performance standard evaluation because is not common practice nor considered business-as-usual, and is therefore eligible for crediting under this protocol.

§ 3.5. Methane Source Boundaries.

(a) The methane destroyed for the purpose of reducing mine methane emissions under this protocol must be methane that would otherwise be emitted into the atmosphere during the normal course of mining activities.

(b) To ensure that virgin coal bed methane is excluded from the destructed mine methane accounted for in this protocol, physical boundaries must be placed on the source of the methane.

(c) All methane from a mine's ventilation and drainage systems must be collected from within the mine extents according to an up-to-date mine plan.

(d) Additional physical boundaries on the basis of activity type are as follows:

(1) Active underground mine ventilation air methane activities may account for:

(A) all destructed methane contained in VAM collected from a mine ventilation system; and

(B) all destructed mine methane contained in mine gas extracted from a methane drainage system used to supplement VAM.

(2) Active underground mine methane drainage activities may account for:

(A) destructed mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mined seam through pre-mining surface wells and pre-mining in-mine boreholes; and

(B) all destructed mine methane contained in mine gas extracted through gob wells.

(3) Active surface mine methane drainage activities may account for destructed surface mine methane contained in mine gas extracted from all strata above and up to 50 meters below a mined seam through pre-mining surface wells, pre-mining in-mine boreholes, existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining, abandoned wells that are re-activated, and converted dewatering wells.

(4) Abandoned underground mine methane recovery activities may account for:

(A) Destructed abandoned mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mined seam through pre-mining surface wells and pre-mining in-mine boreholes drilled during active mining operations;

(B) Destructed abandoned mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mine seam through newly drilled surface wells; and

(C) Destructed abandoned mine methane contained in mine gas extracted from strata up to 150 meters above and 50 meters below a mined seam through existing post-mining gob wells.

§ 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* on the date at which the system begins capturing and destroying methane gas upon completion of an initial start-up period.

(b) Per section 95973(a)(2)(B) of the Regulation, compliance offset projects must have an offset project commencement date after December 31, 2006.

§ 3.7. Project Crediting Period.

The crediting period for this protocol is ten years.

§ 3.8. Regulatory Compliance.

(a) An Offset Project Operator or Authorized Project Designee must fulfill all applicable local, regional, and national requirements on environmental impact assessments that apply based on the offset project location.

(b) Offset projects must fulfill 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

(c) 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.

(d) Offset projects are 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.

Chapter 4. GHG Assessment Boundary – Quantification Methodology

The greenhouse gas assessment boundary, or offset project boundary, delineates the GHG emission sources, sinks, and reservoirs (SSRs) that must be included or excluded when quantifying the net change in emissions associated with the installation and operation of a device, or set of devices, associated with the capture and destruction of mine methane. The following GHG assessment boundaries apply to all MMC projects on the basis of activity type:

§ 4.1. Active Underground Mine VAM Activities.

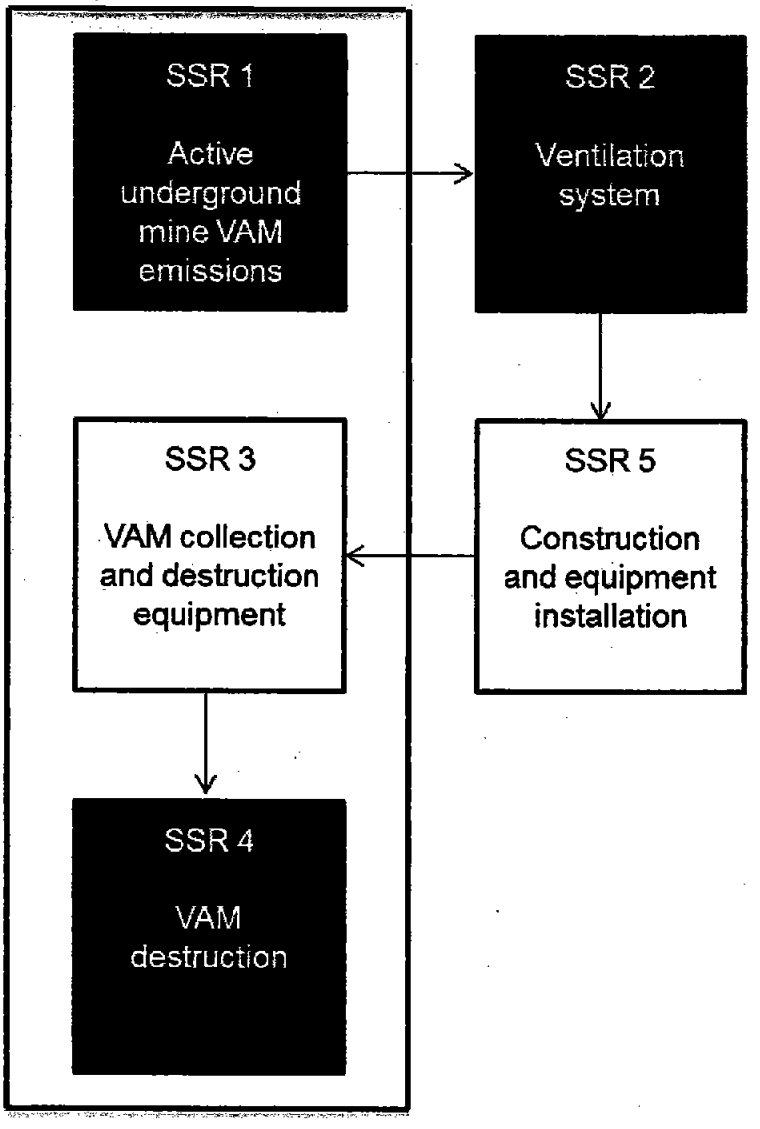
(a) Figure 4.1 illustrates the GHG assessment boundary for active underground mine VAM activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

Figure 4.1. Illustration of the greenhouse gas assessment boundary for active underground mine VAM activities.



(b) Table 4.1 lists the SSRs for active underground mine VAM activities, indicating which gases are included or excluded from the offset project boundary.

Table 4.1. List of the greenhouse gas sinks, sources, and reservoirs for active underground mine VAM activities.

SSR	Description	GHG	Baseline (B) or Project (P)	Included/ Excluded
1	Emissions from the venting of VAM through mine ventilation system	CH_4	B, P	Included
2	Emissions resulting from energy consumed to operate mine ventilation system	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
3	Emissions resulting from energy consumed to operate VAM collection system/ destruction device	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
4	Emissions resulting from VAM destruction	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions of uncombusted methane	CH_4	B, P	Included
5	Emissions from construction and/or installation of new equipment	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from construction	CH_4	n/a	Excluded

§ 4.2. Active Underground Mine Methane Drainage Activities.

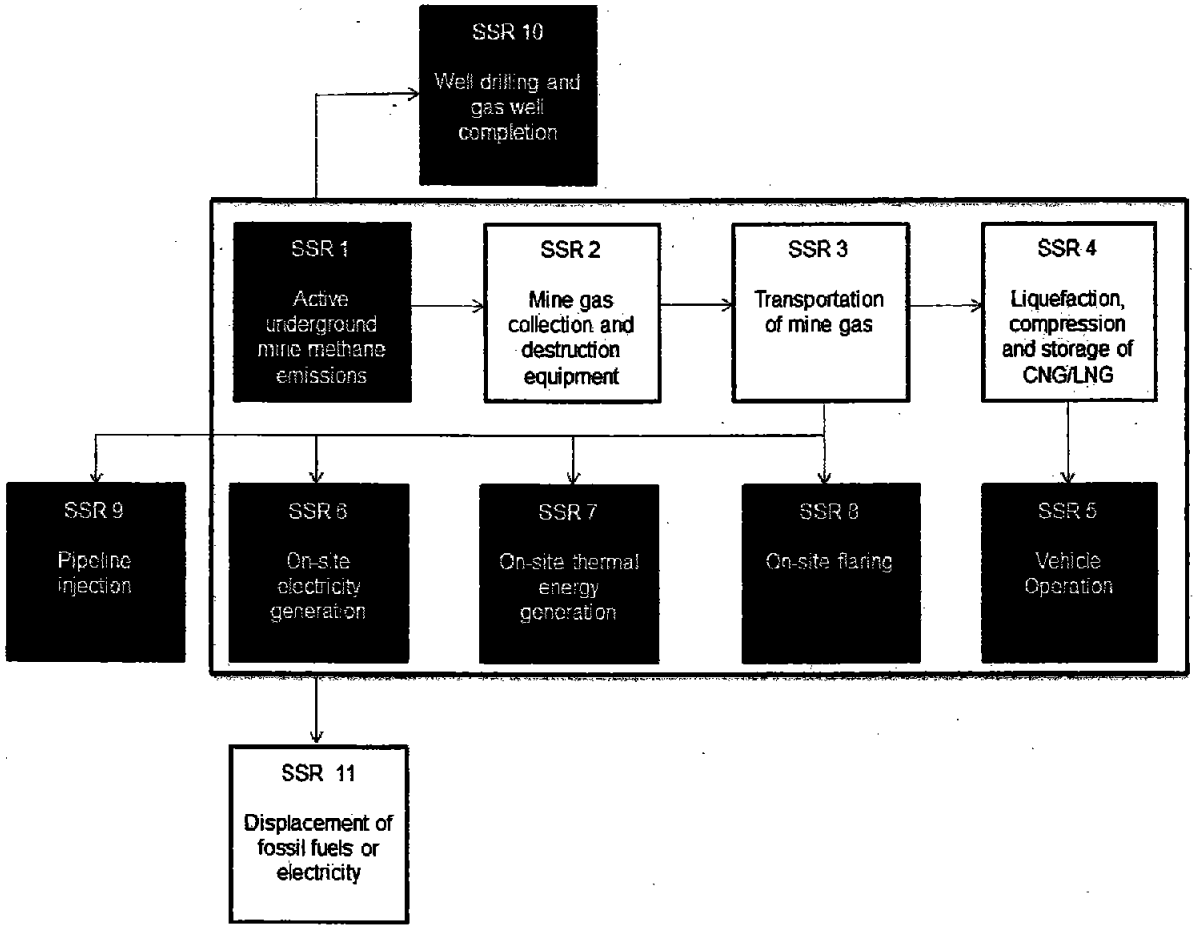
(a) Figure 4.2 illustrates the GHG assessment boundary for active underground mine methane drainage activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

Figure 4.2. Illustration of the greenhouse gas assessment boundary for active underground mine methane drainage activities.



(b) Table 4.2 lists the identified SSRs for active underground mine methane drainage activities, indicating which gases are included or excluded from the offset project boundary.

Table 4.2. List of identified greenhouse gas sinks, sources, and reservoirs for active underground mine methane drainage activities.

SSR	Description	GHG	Relevant to Baseline (B) or Project (P)	Included/ Excluded
1	Emissions from the venting of mine methane extracted through methane drainage system	CH_4	B, P	Included
2	Emissions resulting from energy consumed to operate equipment used to capture or treat drained mine gas	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of equipment used to capture or treat drained mine gas	CH_4	n/a	Excluded
3	Emissions resulting from energy consumed to transport mine gas to treatment or destruction equipment	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from the on-site transportation of mine gas	CH_4	n/a	Excluded
4	Emissions resulting from energy consumed to operate equipment used to liquefy, compress, or store methane for vehicle use.	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of equipment used to liquefy, compress, or store methane for vehicle use	CH_4	n/a	Excluded
5	Emissions resulting from methane combustion during vehicle operation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during vehicle operation	CH_4	B, P	Included
6	Emissions resulting from methane combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during on-site electricity generation	CH_4	B, P	Included
7	Emissions resulting from methane combustion during on-site thermal energy generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during on-site thermal energy generation	CH_4	B, P	Included
8	Emissions resulting from	CO_2	B, P	Included

	methane combustion during on-site flaring	N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during flaring	CH_4	B, P	Included
9	Emissions resulting from methane combustion resulting from pipeline injection	CO_2	n/a	Excluded
		N_2O	n/a	Excluded
	Emissions resulting from the incomplete methane combustion resulting from pipeline injection	CH_4	n/a	Excluded
10	Emissions from well drilling and gas well completion	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from well drilling and gas well completion	CH_4	n/a	Excluded
11	Emission reductions resulting from the displacement of fossil fuels or electricity	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

§ 4.3. Active Surface Mine Methane Drainage Activities.

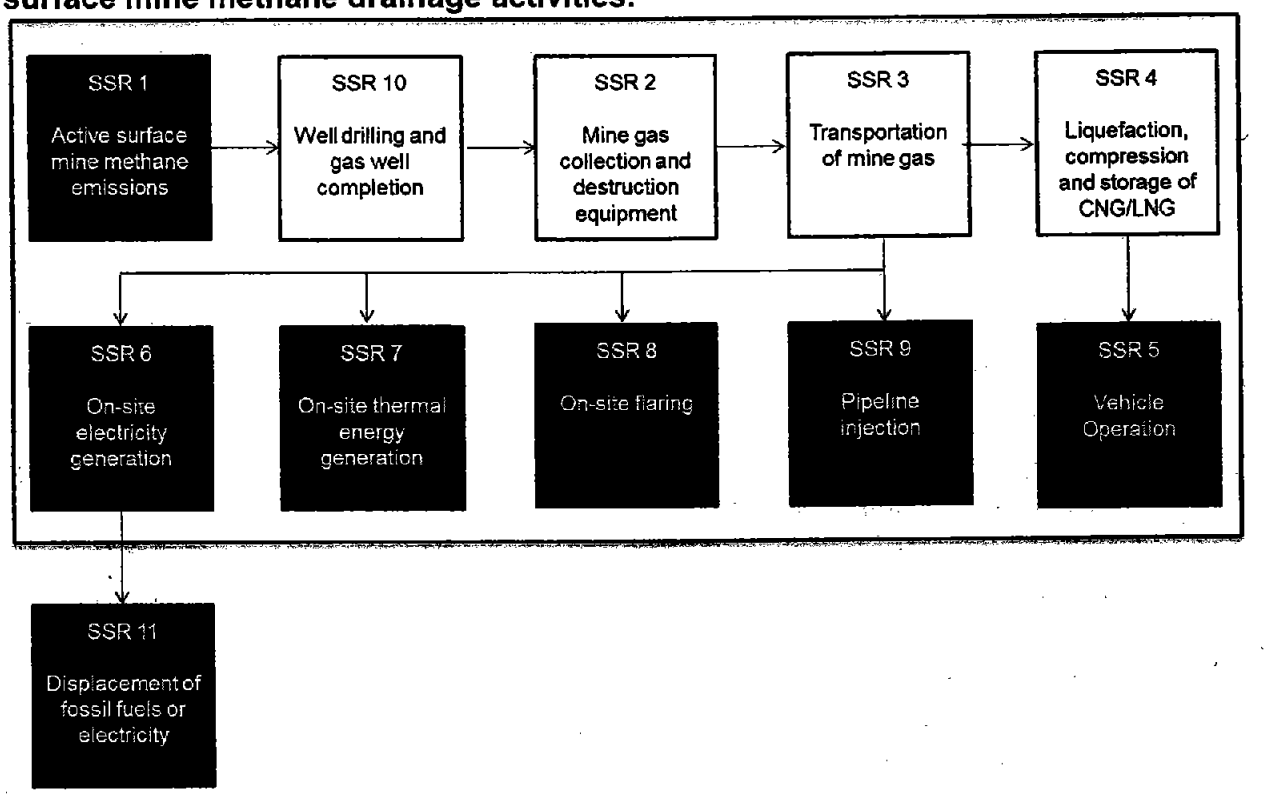
(a) Figure 4.3 illustrates the GHG assessment boundary for active surface mine methane drainage activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

Figure 4.3. Illustration of the greenhouse gas assessment boundary for active surface mine methane drainage activities.



(b) Table 4.3 lists the SSRs for active surface mine methane drainage activities, indicating which gases are included or excluded from the offset project boundary.

Table 4.3. List of the greenhouse gas sinks, sources, and reservoirs for active surface mine methane drainage activities.

SSR	Description	GHG	Relevant to Baseline (B) or Project (P)	Included/ Excluded
1	Emissions from the venting of mine methane during the mining process	CH_4	B, P	Included
2	Emissions resulting from energy consumed to operate equipment used to capture or treat drained mine gas	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of equipment used to capture or treat drained mine gas	CH_4	n/a	Excluded
3	Emissions resulting from energy consumed to transport mine gas to treatment or destruction equipment	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from the on-site transportation of mine gas	CH_4	n/a	Excluded
4	Emissions resulting from energy	CO_2	P	Included

	consumed to operate equipment used to liquefy, compress, or store methane for vehicle use.	CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of equipment used to liquefy, compress, or store methane for vehicle use	CH_4	n/a	Excluded
5	Emissions resulting from methane combustion during vehicle operation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during vehicle operation	CH_4	B, P	Included
6	Emissions resulting from methane combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during on-site electricity generation	CH_4	B, P	Included
7	Emissions resulting from methane combustion during on-site thermal energy generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during on-site thermal energy generation	CH_4	B, P	Included
8	Emissions resulting from methane combustion during on-site flaring	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during flaring	CH_4	B, P	Included
9	Emissions resulting from methane combustion resulting from pipeline injection	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from the incomplete methane combustion resulting from pipeline injection	CH_4	B, P	Included
10	Emissions from well drilling and well gas completion	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from well drilling and gas well completion	CH_4	n/a	Excluded
11	Emission reductions resulting from the displacement of fossil fuels or electricity	CO_2	n/a	Excluded
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

§ 4.4. Abandoned Underground Mine Methane Recovery Activities.

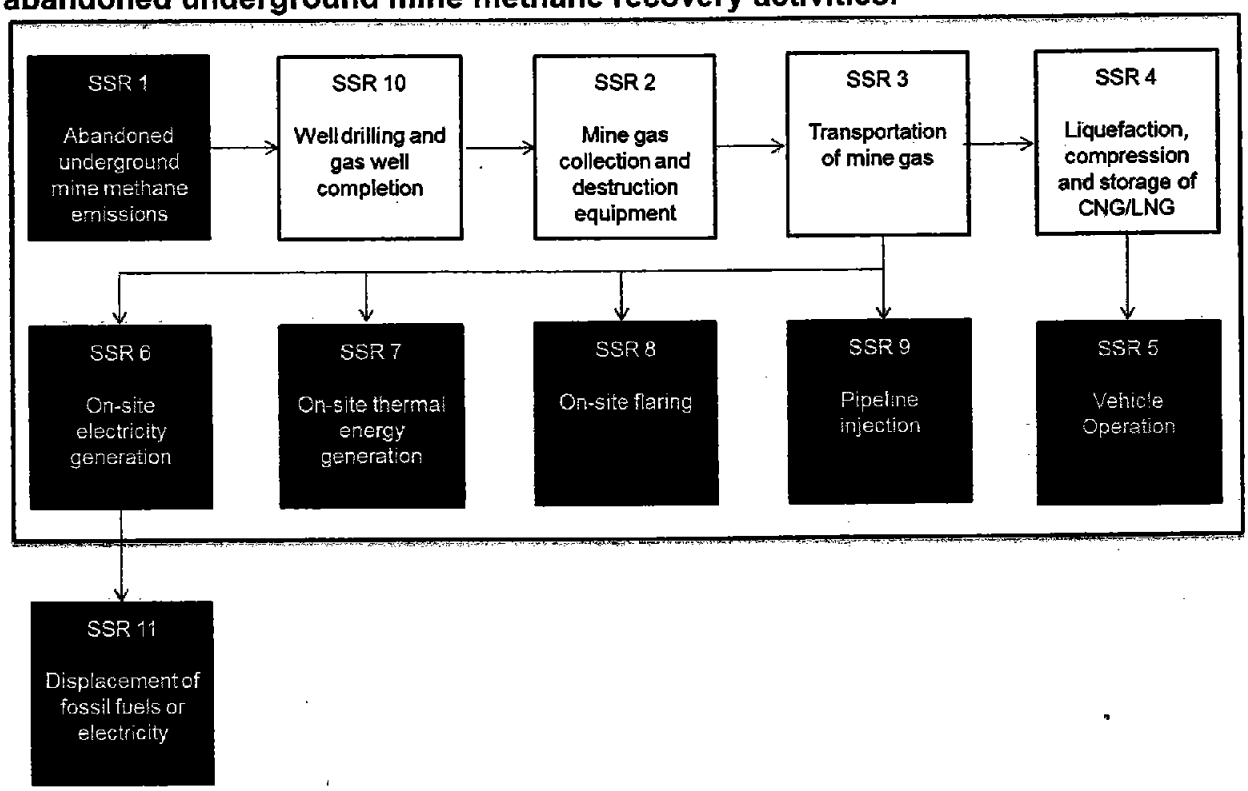
(a) Figure 4.4 illustrates the GHG assessment boundary for abandoned underground mine methane recovery activities, indicating which SSRs are included or excluded from the offset project boundary.

(1) All SSRs within the bold line are included and must be accounted for under this protocol.

(2) SSRs in shaded boxes are relevant to the baseline and project emissions.

(3) SSRs in unshaded boxes are relevant only to the project emissions.

Figure 4.4. Illustration of the greenhouse gas assessment boundary for abandoned underground mine methane recovery activities.



(b) Table 4.4 lists the SSRs for abandoned underground mine methane recovery activities, indicating which gases are included or excluded from the offset project boundary.

Table 4.4. List of the greenhouse gas sinks, sources, and reservoirs for abandoned underground mine methane recovery activities.

SSR	Description	GHG	Relevant for Baseline (B) or Project (P)	Included / Excluded
1	Emissions of mine methane liberated after the conclusion of mining operations	CH_4	B, P	Included
2	Emissions resulting from energy consumed to operate equipment used to collect or treat drained mine gas	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded

	Fugitive emissions from operation of equipment used to collect or treat drained mine gas	CH_4	n/a	Excluded
3	Emissions resulting from energy consumed to transport mine gas to treatment or destruction equipment	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from the on-site transportation of mine gas	CH_4	n/a	Excluded
4	Emissions resulting from energy consumed to operate equipment used to liquefy, compress, or store methane for vehicle use.	CO_2	P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from operation of equipment used to liquefy, compress, or store methane for vehicle use	CH_4	n/a	Excluded
5	Emissions resulting from methane combustion during vehicle operation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during vehicle operation	CH_4	B, P	Included
6	Emissions resulting from methane combustion during on-site electricity generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during on-site electricity generation	CH_4	B, P	Included
7	Emissions resulting from methane combustion during on-site thermal energy generation	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during on-site electricity generation	CH_4	B, P	Included
8	Emissions resulting from methane combustion during on-site flaring	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from incomplete methane combustion during flaring	CH_4	B, P	Included
9	Emissions resulting from methane combustion resulting from pipeline injection	CO_2	B, P	Included
		N_2O	n/a	Excluded
	Emissions resulting from the incomplete methane combustion resulting from pipeline injection	CH_4	B, P	Included
10	Emissions from well drilling and well gas completion	CO_2	B, P	Included
		CH_4	n/a	Excluded
		N_2O	n/a	Excluded
	Fugitive emissions from well drilling and gas well completion	CH_4	n/a	Excluded
11	Emission reductions resulting	CO_2	n/a	Excluded

	from the displacement of fossil fuels or electricity	CH_4	n/a	Excluded
		N_2O	n/a	Excluded

Chapter 5. Quantifying GHG Emission Reductions – Quantification Methodology

(a) GHG emission reductions from an MMC project are quantified by comparing actual project emissions to project baseline emissions at the mine.

(b) Offset Project Operators and Authorized Project Designees must use the activity type-specific calculation methods provided in this protocol to determine baseline and project GHG emissions.

(c) GHG emission reductions must be quantified on at least an annual basis. The length of time over which GHG emission reductions are quantified is called the "reporting period."

(d) Measurements used to quantify emission reductions must be corrected to standard conditions of 60°F and 14.7 pounds per square inch (1 atm).

(e) Global warming potential values must be determined consistent with the definition of Carbon Dioxide Equivalent in MRR section 95102(a).

§ 5.1. Active Underground Mine Ventilation Air Methane Activities.

(a) GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 5.1.

Equation 5.1: GHG Emission Reductions

$ER = BE - PE$

Where,

ER	=	Emission reductions achieved by the project during the reporting period (tCO_2e)
BE	=	Baseline emissions during the reporting period (tCO_2e)
PE	=	Project emissions during the reporting period (tCO_2e)

§ 5.1.1. Quantifying Baseline Emissions

(a) Baseline emissions for a reporting period (BE) must be estimated by summing the baseline emissions for all SSRs identified as included in the baseline in Table 4.1 and by using Equation 5.2.

Equation 5.2: Baseline Emissions

$BE = BE_{MD} + BE_{MR}$

Where,

BE	=	Baseline emissions during the reporting period (tCO_2e)
BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)

(b) Baseline emissions from the destruction of methane (BE_{MD}) must be quantified using Equations 5.3 and 5.4.

(c) BE_{MD} must include the estimated CO_2 emissions from the destruction of VAM by non-qualifying devices.

(d) The volume or mass of VAM that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be the determined by calculating and comparing:

(1) The volume or mass of VAM sent to non-qualifying destruction devices during the reporting period, adjusted for temperature and pressure using Equation 5.11, if applicable; and

(2) The volume or mass of VAM sent to non-qualifying destruction devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using Equation 5.11, if applicable, and averaged according to the length of the reporting period.

(3) The volume or mass of VAM sent to non-qualifying devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using Equation 5.11, if applicable, and averaged according to the length of the reporting period.

(e) The largest of the three above quantities must be used for $VAM_{B,i}$ in Equation 5.4.

(f) If using a quantity from calculation (2) or (3) above and the project does not have data on the methane concentration of ventilation air in ventilation air exhaust to

use in Equations 5.15, the highest single-hour average concentration of ventilation air in ventilation air exhaust during the reporting period must be used in its place.

(g) If using a quantity from calculation (2) or (3) above and the project does not have data on the methane concentration of ventilation air sent to destruction device to use in Equations 5.16, the highest single-hour average methane concentration of ventilation air sent to destruction device must be used in its place.

(h) For the purpose of baseline quantification, only non-qualifying devices that were operating during the year prior to offset project commencement should be taken into account.

(i) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

Equation 5.3: Baseline Emissions from Destruction of Methane

$$BE_{MD} = \sum_{i} MD_{B,i} \times CEF_{CH4}$$

Where,

BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (oxidation or alternative combustion end use)
$MD_{B,i}$	=	Methane that would be destroyed through use i by non qualifying devices during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

Equation 5.4: Methane Destroyed in Baseline

$$MD_{B,i} = \sum_{i} (VAM_{B,i} \times C_{CH4} \times 0.0423 \times 0.000454 - BE_{NO})$$

Where,

$VAM_{B,i}$	=	Volume of VAM that would have been sent to a non-qualifying device for destruction through use i during the reporting period in the baseline scenario (scf)
C_{CH4}	=	Weighted average of measured methane concentration of captured ventilation air sent to non-qualifying devices; calculated separately for each device (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

BE_{NO} = Baseline emissions of non-oxidized methane that would be emitted from oxidation of the VAM stream during the reporting period (tCH_4)

With:

$$C_{CH4} = \frac{\sum_t VAM_{flow,t} \times C_{CH4,t}}{\sum_t VAM_{flow,t}}$$

Where,

$C_{CH4,t}$ = Hourly average methane concentration of ventilation air sent to destruction device (scf CH_4/scf)

$VAM_{flow,t}$ = Hourly average flow of ventilation air sent to destruction device (scf/hour)

And:

$BE_{NO} = VAM_{FLOW,y} \times TIME_y \times C_{CH4,exhaust} \times 0.0423 \times 0.000454$

Where,

$VAM_{FLOW,y}$ = Corrected average flow rate or total volume of ventilation air that would be entering the non qualifying destruction device during period y, adjusted to 60°F and 1 atm (scf/unit of time)

$TIME_y$ = Time during which non qualifying destruction device would be operational during period y (m)

$C_{CH4,exhaust}$ = Weighted average of measured methane concentration in the ventilation air exhaust (scf CH_4/scf)

With:

$$C_{CH4,exhaust} = \frac{\sum_t VAM_{flow,t} \times C_{CH4,exhaust,t}}{\sum_t VAM_{flow,t}}$$

Where,

$C_{CH4,exhaust,t}$ = Hourly average methane concentration of ventilation air in ventilation air exhaust (scf CH_4/scf)

$VAM_{flow,t}$ = Hourly average flow of ventilation air sent to destruction device (scf /hour)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(j) Baseline emissions from the release of methane (BE_{MR}) must be quantified using Equation 5.5.

(k) BE_{MR} must account for the total amount of methane actually destroyed by all qualifying and non-qualifying devices.

(l) VAM project activities may supplement VAM with mine gas (MG) extracted from a methane drainage system to either increase or help balance the concentration of methane flowing into the destruction device. If MG is used to supplement VAM, the MG destructed by the project during the reporting period must be accounted for using Equation 5.5 either as $MG_{SUPP,i,}$ if VAM flow and mine methane flow are monitored separately, or through $VAM_{P,i}$ if only the resulting enriched flow is monitored.

(m) Methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions since it is vented in both scenarios.

Equation 5.5: Baseline Emissions from Release of Methane

$$BE_{MR} = \sum_{i} [(VAM_{P,i} \times C_{CH4} - VAM_{B,i} \times C_{CH4}) + MG_{SUPP,i} \times C_{CH4MG}] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

Where,

BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)
i	=	Use of methane (oxidation or alternative combustion end use)
$VAM_{P,i}$	=	Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the project during the reporting period (scf)
$VAM_{B,i}$	=	Volume of ventilation air that would have sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
C_{CH4}	=	Weighted average of measured methane concentration of captured ventilation air sent to qualifying and non-qualifying devices; calculated separately for each device (scf CH_4/scf)

$MG_{SUPP,i}$	=	Volume of mine methane extracted from a methane drainage system and sent to qualifying and non-qualifying devices for destruction with VAM (scf)
C_{CH4MG}	=	Weighted average of measured methane concentration of captured mine gas (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4
GWP_{CH4}	=	Global warming potential of methane (tCO_2e/tCH_4)

With:

$$C_{CH4} = \frac{\sum_t VAM_{flow,t} \times C_{CH4,t}}{\sum_t VAM_{flow,t}}$$

Where,

$C_{CH4,t}$	=	Hourly average methane concentration of ventilation air sent to destruction device (scf CH_4/scf)
$VAM_{flow,t}$	=	Hourly average flow of ventilation air sent to destruction device (scf /hour)

And:

$$C_{CH4MG} = \frac{\sum_t DV_{MG,t} \times C_{CH4,MG,t}}{\sum_t DV_{MG,t}}$$

Where,

$C_{CH4,MG,t}$	=	Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf CH_4/scf)
$DV_{MG,t}$	=	Daily volume of mine gas sent with ventilation air to destruction device (scf /day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

§ 5.1.2. Quantifying Project Emissions.

(a) Project emissions must be quantified on an annual basis.

(b) Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 4.1 and using Equation 5.6.

(c) Methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions since it is vented in both scenarios.

Equation 5.6: Project Emissions

$PE = PE_{EC} + PE_{MD} + PE_{UM}$

Where,

PE	=	Project emissions during the reporting period (tCO_2e)
PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period (tCO_2e)

(d) If the project uses fossil fuel or grid electricity to power additional equipment required for project activities, the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 5.7.

Equation 5.7: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF,})}{1000}$$

Where,

PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
$CONS_{ELEC}$	=	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	=	CO_2 emission factor of electricity used from Appendix A (tCO_2e/MWh)
$CONS_{HEAT}$	=	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{HEAT}	=	CO_2 emission factor of heat used from Appendix A (kg CO_2/volume)
$CONS_{FF}$	=	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	=	CO_2 emission factor of fossil fuel used from Appendix A (kg CO_2/volume)
1/1000	=	Conversion of kg to metric tons

(e) Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equations 5.8 and 5.9.

(f) PE_{MD} must include the estimated CO_2 emissions from the destruction of VAM by all qualifying and non-qualifying devices.

(g) If MG is used to supplement VAM, the MG destructed by the project during the reporting period must be accounted for using Equation 5.9 either as $MG_{SUPP,i}$, if VAM flow and mine methane flow are monitored separately, or through $VAM_{P,i}$ if only the resulting enriched flow is monitored.

Equation 5.8: Project Emissions from Destruction of Methane

$$PE_{MD} = \sum_i MD_{P,i} \times CEF_{CH4}$$

Where,

PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (oxidation or alternative combustion end use) by all qualifying and non-qualifying devices
$MD_{P,i}$	=	Methane destroyed by use i during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

Equation 5.9: Methane Destroyed

$$MD_{P,i} = \sum_i MM_{P,i} - PE_{NO}$$

Where,

$MD_{P,i}$	=	Methane destroyed by use i during the reporting period (tCH_4)
i	=	Use of methane (oxidation or alternative combustion end use) by all qualifying and non-qualifying devices
$MM_{P,i}$	=	Mine methane sent to qualifying and non-qualifying destruction devices for destruction through use i during the reporting period corrected to standard conditions, if applicable, for pressure and temperature (tCH_4)
PE_{NO}	=	Project emissions of non-oxidized methane from oxidation of the VAM stream during the reporting period (tCH_4)

With:

$$MM_{P,i} = (VAM_{P,i} \times C_{CH4} + MG_{SUPP,i} \times C_{CH4MG}) \times 0.0423 \times 0.000454$$

Where,

$VAM_{P,i}$ = Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the project during the reporting period (scf)

C_{CH4} = Weighted average of measured methane concentration of captured ventilation air sent to qualifying and non-qualifying devices; calculated separately for each device (scf CH_4/scf)

$MG_{SUPP,i}$ = Volume of mine methane extracted from a methane drainage system and sent to destruction device with VAM (scf)

C_{CH4MG} = Weighted average of measured methane concentration of captured mine gas (scf CH_4/scf)

0.0423 = Density of methane (lb CH_4/scf CH_4)

0.000454 = tCH_4/lb CH_4

With:

$VAM_{P,i} = VAM_{FLOW,y} \times TIME_y$

Where,

$VAM_{FLOW,y}$ = Average flow rate of ventilation air entering the destruction device during period y corrected to standard conditions, if applicable, for inlet flow gas pressure and temperature (scfm)

$TIME_y$ = Time during which destruction device is operational during period y (m)

And:

$$C_{CH4} = \frac{\sum_t VAM_{flow,t} \times C_{CH4,t}}{\sum_t VAM_{flow,t}}$$

Where,

$C_{CH4,t}$ = Hourly average methane concentration of ventilation air sent to destruction device (scf CH_4/scf)

$VAM_{flow,t}$ = Hourly average flow of ventilation air sent to destruction device (scf/hour)

And:

$$C_{CH4MG} = \frac{\sum_t DV_{MG,t} \times C_{CH4,MG,t}}{\sum_t DV_{MG,t}}$$

Where,

$C_{CH4,MG,t}$ = Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf CH_4/scf)

$DV_{MG,t}$ = Daily volume of mine gas sent with ventilation air to destruction device (scf/day)

And:

$PE_{NO} = VAM_{FLOW,y} \times TIME_y \times C_{CH4,exhaust} \times 0.0423 \times 0.000454$

Where,

$C_{CH4,exhaust}$ = Weighted average of measured methane concentration in the ventilation air exhaust (scf CH_4/scf)

With:

$$C_{CH4,exhaust} = \frac{\sum_t VAM_{flow,t} \times C_{CH4,exhaust,t}}{\sum_t VAM_{flow,t}}$$

Where,

$C_{CH4,exhaust,t}$ = Hourly average methane concentration of ventilation air in ventilation air exhaust (scf CH_4/scf)

$VAM_{flow,t}$ = Hourly average flow of ventilation air exhaust sent to destruction device (scf /hour)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(h) Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 5.10.

Equation 5.10: Uncombusted Methane Emissions

$PE_{UM} = PE_{NO} \times GWP_{CH4}$

Where,

PE_{UM} = Project emissions from uncombusted methane during the reporting period (tCO_2e)

PE_{NO} = Project emissions of non-oxidized methane from oxidation of the VAM stream during the reporting period (tCH_4)

GWP_{CH4} = Global warming potential of methane (tCO_2e/tCH_4)

With,

$PE_{NO} = VAM_{FLOW,y} \times TIME_y \times C_{CH4,exhaust} \times 0.0423 \times 0.000454$

Where,

$VAM_{FLOW,y}$ = Corrected average flow rate or total volume of ventilation air entering the destruction device during period y, adjusted to 60°F and 1 atm (scf/unit of time)

$TIME_y$ = Time during which destruction device is operational during period y (m)

$C_{CH4,exhaust}$ = Weighted average of measured methane concentration in the ventilation air exhaust (scf CH_4/scf)

With:

$$C_{CH4,exhaust} = \frac{\sum_t VAM_{flow,t} \times C_{CH4,exhaust,t}}{\sum_t VAM_{flow,t}}$$

Where,

$C_{CH4,exhaust,t}$ = Hourly average methane concentration of ventilation air in ventilation air exhaust (scf CH_4/scf)

$VAM_{flow,t}$ = Hourly average flow of ventilation air exhaust sent to destruction device (scf /hour)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(i) If gas flow metering equipment does not internally correct for temperature and pressure, apply Equation 5.11 to the flow rate of ventilation air entering the destruction device.

Equation 5.11: VAM Corrected for Temperature and Pressure

$$VAM_{FLOW,y} = VAM_{FLOWmeas,y} \times \frac{520}{T_{VAMinflowy}} \times \frac{P_{VAMinflow,y}}{1}$$

Where,

$VAM_{FLOW,y}$	=	Corrected average flow rate or total volume of ventilation air entering the destruction device during period y, adjusted to 60°F and 1 atm (scf/unit of time)
$VAM_{FLOWmeas,y}$	=	Measured average flow rate or total volume of ventilation air entering the destruction device as measured during period y (scf/unit of time)
$T_{VAMinflow,y}$	=	Measured temperature of ventilation air entering the destruction device for the time interval y, °R=°F+460 (°R)
$P_{VAMinflow,y}$	=	Measured pressure of ventilation air entering the destruction device for the time interval y (atm)

§ 5.2. Active Underground Mine Methane Drainage Activities.

(a) GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 5.12.

(b) If a mine that has historically sent mine methane (MM) to a natural gas pipeline ceases to do so, MM from that source (pre-mining surface wells, pre-mining in-mine boreholes, or post-mining gob wells) is ineligible for emission reduction under this protocol, even if the MM is sent to an otherwise eligible destruction device. If a mine begins to inject MM into a natural gas pipeline while the offset project is ongoing, MM from that source is ineligible for emission reductions going forward.

(c) MM that is injected into a natural gas pipeline in the project scenario is not accounted for in the project emissions or baseline emissions, since it is injected in both scenarios.

Equation 5.12: GHG Emission Reductions

$ER = BE - PE$

Where,

ER	=	Emission reductions achieved by the project during the reporting period (tCO_2e)
BE	=	Baseline emissions during the reporting period (tCO_2e)
PE	=	Project emissions during the reporting period (tCO_2e)

§ 5.2.1. Quantifying Baseline Emissions.

(a) Baseline emissions for a reporting period (BE) must be estimated by summing the baseline emissions for all SSRs identified as included in the baseline in Table 4.2 and using Equation 5.13.

Equation 5.13: Baseline Emissions

$BE = BE_{MD} + BE_{MR}$

Where,

BE	=	Baseline emissions during the reporting period (tCO_2e)
BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)

(b) Baseline emissions from the destruction of MM (BE_{MD}) must be quantified using Equations 5.14 and 5.15.

(c) BE_{MD} must include the estimated CO_2 emissions from the destruction of MM in non-qualifying devices.

(d) Mine gas (MG) can originate from three distinct sources for active underground mine methane drainage activities: pre-mining surface wells, pre-mining in-mine boreholes, and post-mining gob wells. MG from these sources must be measured and accounted for individually per the equations in this section.

(e) For each eligible methane source, the volume or mass of MG that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be the determined by calculating and comparing:

(1) The volume or mass of MG sent to non-qualifying devices during the reporting period, adjusted for temperature and pressure using Equation 5.23, if applicable; and

(2) The volume or mass of MG sent to non-qualifying devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using Equation 5.23, if applicable, and averaged according to the length of the reporting period.

(3) The volume or mass of MG sent to non-qualifying devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using Equation 5.23, if applicable, and averaged according to the length of the reporting period.

(f) For each methane source, the largest of the three above quantities must be used in Equation 5.15.

(g) If using a quantity from calculation (2) or (3) above and the project does not have data on the concentration of the methane to use in Equations 5.15 and 5.16, the highest single-day average methane concentration measured for that methane source during the reporting period must be used in its place.

(h) For the purpose of baseline quantification, only non-qualifying devices that were operating during the year prior to offset project commencement should be taken into account.

(i) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

Equation 5.14: Baseline Emissions from Destruction of Methane

$$BE_{MD} = \sum_{i} MD_{B,i} \times CEF_{CH4}$$

Where,

BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.)
$MD_{B,i}$	=	Methane that would be destroyed through use i by non qualifying devices during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

Equation 5.15: Methane Destroyed in Baseline

$$MD_{B,i} = \sum_{i} MM_{B,i} \times DE_i$$

Where,

$MD_{B,i}$	=	Methane that would be destroyed through use i by non qualifying devices during the reporting period (tCH_4)

i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by non-qualifying devices
$MM_{B,i}$	=	Methane that would have been sent to non-qualifying devices for destruction through use i during the reporting period; calculated separately for each device (tCH_4)
DE_i	=	Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

With:

$$MM_{B,i} = \sum_i (PSW_{B,i} \times C_{CH4} + PIB_{B,i} \times C_{CH4} + ECW_{B,i} \times C_{CH4} + AWR_{B,i} \times C_{CH4} + CDW_{B,i} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{B,i}$	=	Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
$PIB_{B,i}$	=	Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
$PGW_{B,i}$	=	Volume of MG from post-mining gob wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)

DV_t	=	Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(j) Baseline emissions from the release of methane (BE_{MR}) must be quantified using Equation 5.16.

(k) BE_{MR} must account for the total amount of methane actually destroyed by all qualifying and non-qualifying devices.

(l) Emissions from the release of methane through pre-mining surface wells are only accounted for in the baseline during the reporting period(s) in which the emissions would have occurred (i.e. when the well is mined through). For the purposes of this protocol, a well at an active underground mine is considered mined through when any of the following occur:

(1) The working face intersects the borehole, as long as the endpoint of the borehole is not more than 50 meters below the mined coal seam;

(2) The working face passes directly underneath the bottom of the borehole, as long as the endpoint of the borehole is not more than 150 meters above the mined coal seam;

(3) The working face passes both underneath (not more than 150 meters below the endpoint of the borehole) and to the side of the borehole if room and pillar mining technique is employed and the endpoint of the borehole lies above a block of coal that will be left unmined as a pillar; or

(4) The well produces elevated amounts of atmospheric gases (the percent concentration of nitrogen in mine gas increases by five compared to baseline levels). A full gas analysis using a gas chromatograph must be completed by an ISO 17025 accredited lab. To ensure that elevated nitrogen levels are the result of a well being mined through and not the result of a leak in the well, the gas analysis must show that oxygen levels did not increase by the same proportion as the nitrogen levels.

(m) If using option 1, 2, or 3 to demonstrate that a well is mined through, an up-to-date mine plan must be used to identify which wells were mined through, based on the above criteria, and therefore eligible for baseline quantification in any given reporting period.

(n) If the mine plan calls for mining past rather than through a borehole, MM from that borehole is eligible for quantification in the baseline when the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum.

(o) If an MMC project at an active underground mine consists of both VAM and methane drainage activities, mine gas extracted from a methane drainage system (MG) may be used to supplement VAM to either increase or help balance the concentration of methane flowing into the destruction device. If MG is used to supplement VAM, the MG destructed by the project during the reporting period must be accounted for using Equation 5.16 as $MG_{SUPP,i,}$.

(p) MM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 5.16: Baseline Emissions from Release of Methane

$$BE_{MR} = \sum_{i} [(PSW_{P,i} \times C_{CH4} - PSW_{B,i,} \times C_{CH4\,i}) + (PIB_{P,i} \times C_{CH4} - PIB_{B,i} \times C_{CH4}) + (PGW_{P,i} \times C_{CH4} - PGW_{B,i} \times C_{CH4}) - MG_{SUPP,i} \times C_{CH4MG}] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

Where,

BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, etc.) by all qualifying and non-qualifying devices
$PSW_{P,i}$	=	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.17 in accordance with sections 5.2.1(k), (l) and (m) must be quantified (scf)
$PSW_{B,i}$	=	Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)

$PIB_{P,i}$	=	Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PIB_{B,i}$	=	Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
$PGW_{P,i}$	=	Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PGW_{B,i}$	=	Volume of MG from post-mining gob wells that would have been sent to non-qualifying device for destruction through use i during the reporting period in the baseline scenario (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
$MG_{SUPP,i}$	=	Volume of mine methane extracted from a methane drainage system and sent to qualifying and non-qualifying devices for combustion with VAM (scf)
C_{CH4MG}	=	Weighted average of measured methane concentration of captured mine gas sent with ventilation air methane to destruction device (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4
GWP_{CH4}	=	Global warming potential of methane (tCO_2e/tCH_4)

With,

$PSW_{P,i} = PSWe_i + PSWnqd_i$

Where,

$PSWe_i$	=	Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period. Quantified using Equation 5.17. (scf)
$PSWnqd_i$	=	Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
DV_t	=	Daily volume of mine gas sent to destruction device (scf/day)

And:

$$C_{CH4MG} = \frac{\sum_t DV_{MG,t} \times C_{CH4,MG,t}}{\sum_t DV_{MG,t}}$$

Where,

$C_{CH4,MG,t}$	=	Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf CH_4/scf)
$DV_{MG,t}$	=	Daily volume of mine gas sent with ventilation air to destruction device (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(q) The eligible amount of MG from pre-mining surface wells destroyed by qualifying devices ($PSWe_i$) must be determined by using Equation 5.17.

Equation 5.17: Eligible MG from Pre-mining Surface Boreholes

$PSWe_i = PSWe_{pre,i} + PSWe_{post,i}$

Where,

$PSWe_i$	=	Volume of MG from pre-mining surface wells captured and destroyed by qualifying devices through use i that is eligible for quantification in the reporting period using Equation 5.16 (scf)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, etc.) by all qualifying devices
$PSWe_{pre,i}$	=	Volume of MG destroyed by qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from pre-mining surface wells that were mined through during the current reporting period (scf)
$PSWe_{post,i}$	=	Volume of MG destroyed by qualifying destruction devices in the current reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods (scf)

§ 5.2.2. Quantifying Project Emissions.

(a) Project emissions must be quantified on an annual basis.

(b) Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 4.2 and using Equation 5.18.

(c) Methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions since it is vented in both scenarios.

Equation 5.18: Project Emissions

$PE = PE_{EC} + PE_{MD} + PE_{UM}$

Where,

PE	=	Project emissions during the reporting period (tCO_2e)
PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period (tCO_2e)

(d) If the project uses fossil fuel or grid electricity to power additional equipment required for project activities, the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 5.19.

(e) If the total electricity generated by project activities is greater than the additional electricity consumed for the capture and destruction of methane, then the $CONS_{ELEC}$ term may be omitted from Equation 5.19.

Equation 5.19: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

Where,

PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
$CONS_{ELEC}$	=	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	=	CO_2 emission factor of electricity used from Appendix A (tCO_2e/MWh)
$CONS_{HEAT}$	=	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)

CEF_{HEAT}	=	CO_2 emission factor of heat used from Appendix A (kg CO_2/volume)
$CONS_{FF}$	=	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	=	CO_2 emission factor of fossil fuel used from Appendix A (kg CO_2/volume)
1/1000	=	Conversion of kg to metric tons

(f) Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equations 5.20 and 5.21.

(g) Project emissions must include the CO_2 emissions resulting from the destruction of all MM from pre-mining surface wells that took place during the reporting period regardless of whether or not the well is mined through by the end of the reporting period.

Equation 5.20: Project Emissions from Destruction of Captured Methane

$$PE_{MD} = \sum_{i} MD_{P,i} \times CEF_{CH4}$$

Where,

PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, etc.) by all qualifying and non-qualifying devices
$MD_{P,i}$	=	Methane destroyed by use i during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

(h) The amount of mine methane destroyed (MD_i) must be quantified using Equation 5.21.

(i) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.21: Methane Destroyed

$$MD_{P,i} = \sum_{i} MM_{P,i} \times DE_i$$

Where,

$MD_{P,i}$ = Methane destroyed by use i during the reporting period (tCH_4)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, etc.) by all qualifying and non-qualifying devices

$MM_{P,i}$ = Methane measured sent to qualifying and non-qualifying devices for destruction through use i during the reporting period corrected to standard conditions, if applicable, for pressure and temperature; calculated separately for each device (tCH_4)

DE_i = Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

With:

$$MM_{P,i} = \sum_i (PSW_{P,all,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + PGW_{P,i} \times C_{CH4} - MG_{SUPP,i} \times C_{CH4MG}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{P,all,i}$ = Volume of MG from pre-mining surface wells captured and destroyed by qualifying and non-qualifying devices through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not must be quantified (scf)

$PIB_{P,i}$ = Volume of MG from pre-mining in-mine boreholes captured and destroyed by qualifying and non-qualifying devices through use i during the reporting period (scf)

$PGW_{P,i}$ = Volume of MG from post-mining gob wells captured and destroyed by qualifying and non-qualifying devices through use i during the reporting period (scf)

C_{CH4} = Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)

$MG_{SUPP,i}$ = Volume of mine methane extracted from a methane drainage system and combusted with VAM (scf)

C_{CH4MG} = Weighted average of measured methane concentration of captured mine gas sent with ventilation air to destruction device (scf CH_4/scf)

0.0423 = Density of methane (lb CH_4/scf CH_4)

0.000454 = tCH_4/lb CH_4

And:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_{MG,t}}$$

Where,

$C_{CH4,t}$ = Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane sourc (scf CH_4/scf)

DV_t = Daily volume of mine gas sent to destruction device (scf/day)

And:

$$C_{CH4MG} = \frac{\sum_t DV_{MG,t} \times C_{CH4,MG,t}}{\sum_t DV_{MG,t}}$$

Where,

$C_{CH4,MG,t}$ = Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf CH_4/scf)

$DV_{MG,t}$ = Daily volume of mine gas sent with ventilation air to destruction device (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(j) Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 5.22.

(k) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.22: Uncombusted Methane Emissions

$$PE_{UM} = \sum_i MM_{P,i} \times (1 - DE_i) \times GWP_{CH4}$$

Where,

PE_{UM} = Project emissions from uncombusted methane during the reporting period (tCO_2e)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, etc.) by all qualifying and non-qualifying devices

$MM_{P,i}$	=	Methane measured sent to use i during the reporting period; calculated separately for each destruction device (tCH_4)
DE_i	=	Efficiency of methane destruction device i, either site-specific or from Appendix B (%)
GWP_{CH4}	=	Global warming potential of methane (tCO_2e/tCH_4)

With:

$$MM_{P,i} = \sum_{i} (PSW_{P,all,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + PGW_{P,i} \times C_{CH4} - MG_{SUPP,i} \times C_{CH4MG}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{P,all,i}$	=	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not must be quantified (scf)
$PIB_{P,i}$	=	Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PGW_{P,i}$	=	Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
$MG_{SUPP,i}$	=	Volume of mine methane extracted from a methane drainage system and sent to destruction device with VAM(scf)
C_{CH4MG}	=	Weighted average of measured methane concentration of captured mine gas sent with ventilation air for destruction (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

And:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane sourc (scf CH_4/scf)
DV_t	=	Daily volume of mine gas sent to destruction device (scf/day)

And:

$$C_{CH4MG} = \frac{\sum_t DV_{MG,t} \times C_{CH4,MG,t}}{\sum_t DV_{MG,t}}$$

Where,

$C_{CH4,MG,t}$ = Daily average methane concentration of mine gas sent with ventilation air to destruction device (scf CH_4/scf)

$DV_{MG,t}$ = Daily volume of mine gas sent with ventilation air to destruction device (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(l) If gas flow metering equipment does not internally correct for temperature and pressure, use Equation 5.23 to determine the amount of mine gas sent to each qualifying and non-qualifying device during the reporting period.

Equation 5.23: MG Corrected for Temperature and Pressure

$$MG_{corrected,i,y} = MG_{meas,i,y} \times \frac{520}{T_{MGy}} \times \frac{P_{MG,y}}{1}$$

Where,

$MG_{corrected,i,y}$ = Corrected flow rate or total volume of MG collected for the time interval y at utilization type i, adjusted to 60°F and 1 atm (scf/unit of time)

$MG_{meas,i,y}$ = Measured flow rate or total volume of MG collected for the time interval y at utilization type i (scf/unit of time)

$T_{MG,y}$ = Measured temperature of the MG for the time interval y, °R=°F+460 (°R)

$P_{MG,y}$ = Measured pressure of the MG for the time interval y (atm)

§ 5.3. Active Surface Mine Methane Drainage Activities.

(a) GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) using Equation 5.24.

Equation 5.24: GHG Emission Reductions

$ER = BE - PE$

Where,

ER	=	Emission reductions achieved by the project during the reporting period (tCO_2e)
BE	=	Baseline emissions during the reporting period (tCO_2e)
PE	=	Project emissions during the reporting period (tCO_2e)

§ 5.3.1. Quantifying Baseline Emissions.

(a) Baseline emissions for a reporting period (BE) must be estimated by summing the baseline emissions for all SSRs identified as included in the baseline in Table 4.3 and using Equation 5.25.

Equation 5.25: Baseline Emissions

$BE = BE_{MD} + BE_{MR}$

Where,

BE	=	Baseline emissions during the reporting period (tCO_2e)
BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)

(b) Baseline emissions from the destruction of SMM (BE_{MD}) must be quantified using Equations 5.26 and 5.27.

(c) BE_{MD} must include the estimated CO_2 emissions from the destruction of SMM in non-qualifying devices.

(d) Mine gas (MG) can originate from five distinct sources for active surface mine methane drainage activities: pre-mining surface wells, pre-mining in-mine boreholes, existing coal bed methane (CBM) wells that would otherwise be shut-in and abandoned as a result of encroaching mining, abandoned wells that are re-activated, and converted dewatering wells. MG from these sources must be measured and accounted for individually per the equations in this section.

(e) For each eligible methane source, the volume or mass of MG that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be the determined by calculating and comparing:

(1) The volume or mass of MG sent to non-qualifying destruction devices during the reporting period, adjusted for temperature and pressure using Equation 5.38, if applicable; and

(2) The volume or mass of MG sent to non-qualifying destruction devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using Equation 5.38, if applicable and averaged according to the length of the reporting period.

(3) The volume or mass of MG sent to non-qualifying devices during the time period a law, regulation, or legally binding mandate, in place for less than three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using Equation 5.38, if applicable, and averaged according to the length of the reporting period.

(f) For each methane source, the largest of the three above quantities must be used in Equation 5.27.

(g) If using a quantity from calculation (2) or (3) above and the project does not have data on the concentration of the methane to use in Equations 5.27 and 5.28, the highest single-day average methane concentration measured for that methane source during the reporting period must be used in its place.

(h) For the purpose of baseline quantification, only non-qualifying devices that were operating during the year prior to offset project commencement should be taken into account.

(i) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

Equation 5.26: Baseline Emissions from Destruction of Methane

$$BE_{MD} = \sum_{i} MD_{B,i} \times CEF_{CH4}$$

Where,

BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.)
$MD_{B,i}$	=	Methane that would be destroyed through use i by non qualifying devices during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

Equation 5.27: Methane Destroyed in Baseline

$$MD_{B,i} = \sum_{i} MM_{B,i} \times DE_i$$

Where,

$MD_{B,i}$ = Methane that would be destroyed through use i by non qualifying devices during the reporting period (tCH_4)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by non-qualifying devices

$MM_{B,i}$ = Methane that would have been sent to non qualifying devices for destruction through use i during the reporting period; calculated separately for each device (tCH_4)

DE_i = Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

With:

$$MM_{B,i} = \sum_{i} (PSW_{B,i} \times C_{CH4} + PIB_{B,i} \times C_{CH4} + ECW_{B,i} \times C_{CH4} + AWR_{B,i} \times C_{CH4} + CDW_{B,i} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{B,i}$ = Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)

$PIB_{B,i}$ = Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)

$ECW_{B,i}$ = Volume of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)

$AWR_{B,i}$ = Volume of MG from abandoned wells that are reactivated that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)

$CDW_{B,i}$	=	Volume of MG from converted dewatering wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
C_{CH4}	=	Measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
DV_t	=	Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(j) Baseline emissions from the release of methane (BE_{MR}) must be quantified using Equation 5.28.

(k) BE_{MR} must account for the total amount of methane actually destroyed by all qualifying and non-qualifying devices.

(l) Emissions from the release of methane are only accounted for in the baseline during the reporting period(s) in which the emissions would have occurred (i.e., when the well is mined through). With the exception of pre-mining in-mine boreholes, all other methane sources must demonstrate that the well is mined through. For the purposes of this protocol, a well at an active surface mine is considered mined through when either of the following occurs:

(1) The well is physically bisected by surface mining activities, such as excavation of overburden, drilling and blasting, and removal of the coal.

(2) The well produces elevated amounts of atmospheric gases (the percent concentration of nitrogen in mine gas increases by five compared to baseline levels). A full gas analysis using a gas chromatograph must be completed by an ISO 17025 accredited lab. To ensure that elevated nitrogen levels are the result of a well being mined through and not the result of a leak in the well, the gas analysis must show that oxygen levels did not increase by the same proportion as the nitrogen levels.

(m) If using the first option to demonstrate that a well is mined through, an up-to-date mine plan must be used to identify which wells were mined through and therefore eligible for baseline quantification in any given reporting period.

(n) If the mine plan calls for mining past rather than through a borehole, SMM from that borehole is eligible for quantification in the baseline when the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum.

(o) SMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 5.28: Baseline Emissions from Release of Methane

$$BE_{MR} = \sum_{i} [(PSW_{P,i} \times C_{CH4} - PSW_{B,i} \times C_{CH4}) + (PIB_{P,i} \times C_{CH4} - PIB_{B,i} \times C_{CH4}) + (ECW_{P,i} \times C_{CH4} - ECW_{B,i} \times C_{CH4}) + (AWR_{P,i} \times C_{CH4} - AWR_{B,i} \times C_{CH4}) + (CDW_{P,i} \times C_{CH4} - CDW_{B,i} \times C_{CH4})] \times 0.0423 \times 0.000454 \times GWP_{CH4}$$

Where,

BE_{MR} = Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices

$PSW_{P,i}$ = Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.29 in accordance with sections 5.3.1(k), (l), and (m) must be quantified (scf)

$PSW_{B,i}$ = Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)

$PIB_{P,i}$	=	Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PIB_{B,i}$	=	Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
$ECW_{P,i}$	=	Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.30 in accordance with sections 5.3.1(k), (l), and (m) must be quantified (scf)
$ECW_{B,i}$	=	Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
$AWR_{P,i}$	=	Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.31 in accordance with sections 5.3.1(k), (l), and (m) must be quantified (scf)
$AWR_{B,i}$	=	Volume of MG from abandoned wells that are reactivated that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
$CDW_{P,i}$	=	Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.32 in accordance with sections 5.3.1(k), (l), and (m) must be quantified (scf)
$CDW_{B,i}$	=	Volume of MG from converted dewatering wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4
GWP_{CH4}	=	Global warming potential of methane (tCO_2e/tCH_4)

With,

$PSW_{P,i} = PSWe_i + PSWnqd_i$

Where,

$PSWe_i$ = Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period. Quantified using Equation 5.29. (scf)

$PSWnqd_i$ = Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And,

$ECW_{P,i} = ECWe_i + ECWnqd_i$

Where,

$ECWe_i$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period. Quantified using Equation 5.30. (scf)

$ECWnqd_i$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And,

$AWR_{P,i} = AWRe_i + AWRnqd_i$

Where,

$AWRe_i$ = Volume of MG from abandoned wells that are reactivated sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period. Quantified using Equation 5.31. (scf)

$AWRnqd_i$ = Volume of MG from abandoned wells that are reactivated sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And,

$CDW_{P,i} = CDWe_i + CDWnqd_i$

Where,

$CDWe_i$ = Volume of MG from converted dewatering wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period. Quantified using Equation 5.32. (scf)

$CDWnqd_i$ = Volume of MG from converted dewatering wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)

And:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$ = Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)

DV_t = Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(p) The eligible amount of MG destroyed by qualifying devices must be determined by using Equations 5.29, 5.30, 5.31 and 5.32.

Equation 5.29: Eligible MG from Pre-mining Surface Wells

$PSWe_i = PSWe_{pre,i} + PSWe_{post,i}$

Where,

$PSWe_i$ = Volume of MG from pre-mining surface wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period using Equation 5.28 (scf)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying devices

$PSWe_{pre,i}$ = Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from pre-mining surface wells that were mined through during the current reporting period (scf)

$PSWe_{post,i}$ = Volume of MG sent to qualifying destruction devices in the current reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods (scf)

Equation 5.30: Eligible MG from Existing Coal Bed Methane Wells that Would Otherwise Be Shut-in and Abandoned as a Result of Encroaching Mining

$ECWe_i = ECWe_{pre,i} + ECWe_{post,i}$

Where,

$ECWe_i$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period using Equation 5.28 (scf)

i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying devices
$ECWe_{pre,i}$	=	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during the current reporting period (scf)
$ECWe_{post,i}$	=	Volume of MG sent to qualifying destruction devices in the current reporting period captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during earlier reporting periods (scf)

Equation 5.31: Eligible MG from Abandoned Wells that are Reactivated

$AWRe_i = AWEe_{pre,i} + AWRe_{post,i}$

Where,

$AWRe_i$	=	Volume of MG from abandoned wells that are reactivated sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period using Equation 5.28 (scf)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying devices
$AWRe_{pre,i}$	=	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from abandoned wells that are reactivated that were mined through during the current reporting period (scf)
$AWRe_{post,i}$	=	Volume of MG sent to qualifying destruction devices in the current reporting period captured from abandoned wells that are reactivated that were mined through during earlier reporting periods (scf)

Equation 5.32: Eligible MG from Converted Dewatering Wells that are Reactivated

$CDWe_i = CDWe_{pre,i} + CDWe_{post,i}$

Where,

$CDWe_i$	=	Volume of MG from converted dewatering wells sent to qualifying devices for destruction through use i that is eligible for quantification in the reporting period using Equation 5.28 (scf)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying devices
$CDWe_{pre,i}$	=	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from converted dewatering wells that were mined through during the current reporting period (scf)

$CDWe_{post,i}$	=	Volume of MG sent to qualifying destruction devices in the current reporting period captured from converted dewatering wells that were mined through during earlier reporting periods (scf)

§ 5.3.2 Quantifying Project Emissions.

(a) Project emissions must be quantified on an annual basis.

(b) Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 4.3 and using Equation 5.33.

(c) SMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 5.33: Project Emissions

$PE = PE_{EC} + PE_{MD} + PE_{UM}$

Where,

PE	=	Project emissions during the reporting period (tCO_2e)
PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period (tCO_2e)

(d) If the project uses fossil fuel or grid electricity to power additional equipment required for project activities, the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 5.34.

(e) If the total electricity generated by project activities is greater than the additional electricity consumed for the capture and destruction of methane, then the $CONS_{ELEC}$ term may be omitted from Equation 5.34.

Equation 5.34: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

Where,

PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)

$CONS_{ELEC}$	=	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	=	CO_2 emission factor of electricity used from Appendix A (tCO_2e/MWh)
$CONS_{HEAT}$	=	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{HEAT}	=	CO_2 emission factor of heat used from Appendix A (kg CO_2/volume)
$CONS_{FF}$	=	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	=	CO_2 emission factor of fossil fuel used from Appendix A (kg CO_2/volume)
1/1000	=	Conversion of kg to metric tons

(f) Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equations 5.35 and 5.36.

(g) Project emissions must include the CO_2 emissions resulting from the destruction of SMM that took place during the reporting period regardless of whether or not the well is mined through by the end of the reporting period.

Equation 5.35: Project Emissions from Destruction of SMM

$$PE_{MD} = \sum_{i} MD_{P,i} \times CEF_{CH4}$$

Where,

PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices
$MD_{P,i}$	=	Methane destroyed by use i during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

(h) The amount of mine methane destroyed (MD_i) must be quantified using Equation 5.36.

(i) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to

be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.36: Methane Destroyed

$$MD_{P,i} = \sum_{i} MM_{P,i} \times DE_i$$

Where,

$MD_{P,i}$ = Methane destroyed by use i during the reporting period (tCH_4)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices

$MM_{P,i}$ = Methane measured sent to qualifying and non-qualifying devices for destruction through use i during the reporting period corrected to standard conditions, if applicable, for pressure and temperature; calculated separately for each device (tCH_4)

DE_i = Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

With:

$$MM_{P,i} = \sum_{i} (PSW_{P,all,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + ECW_{P,all,i} \times C_{CH4} + AWR_{P,all,i} \times C_{CH4} \times CDW_{P,all,i,} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{P,all,i}$ = Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

$PIB_{P,i}$ = Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)

$ECW_{P,all,i}$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

$AWR_{P,all,i}$ = Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

$CDW_{P,all,i}$	=	Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
DV_t	=	Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(j) Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 5.37.

(k) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.37: Uncombusted Methane Emissions

$$PE_{UM} = \sum_i MM_{P,i} \times (1 - DE_i) \times GWP_{CH4}$$

Where,

PE_{UM} = Project emissions from uncombusted methane during the reporting period (tCO_2e)

i = Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices

$MM_{P,i}$ = Methane measured sent to qualifying anod non-qualifying devices for destruction through use i during the reporting period; calculated separately for each device (tCH_4)

DE_i = Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

GWP_{CH4} = Global warming potential of methane (tCO_2e/tCH_4)

With,

$$MM_{P,i} = \sum_i (PSW_{P,all,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + ECW_{P,all,i} \times C_{CH4} + AWR_{P,all,i} \times C_{CH4} \times CDW_{P,all,i} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{P,all,i}$ = Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

$PIB_{P,i}$ = Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)

$ECW_{P,all,i}$ = Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

$AWR_{P,all,i}$ = Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

$CDW_{P,all,i}$ = Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified (scf)

C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
DV_t	=	Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(l) If gas flow metering equipment does not internally correct for temperature and pressure, use Equation 5.38 to determine the amount of mine gas sent to each qualifying and non-qualifying device during the reporting period.

Equation 5.38: MG Corrected for Temperature and Pressure

$$MG_{corrected,i,y} = MG_{meas,i,y} \times \frac{520}{T_{MGy}} \times \frac{P_{MG,y}}{1}$$

Where,

$MG_{corrected,i,y}$	=	Corrected flow rate or total volume of MG collected for the time interval y at utilization type i, adjusted to 60°F and 1 atm (scf/unit of time)
$MG_{meas,i,y}$	=	Measured flow rate or total volume of MG collected for the time interval y at utilization type i (scf/unit of time)
$T_{MG,y}$	=	Measured temperature of the MG for the time interval y, °R=°F+460 (°R)
$P_{MG,y}$	=	Measured pressure of the MG for the time interval y (atm)

§ 5.4. Abandoned Underground Mine Methane Recovery Activities.

(a) GHG emission reductions for a reporting period (ER) must be quantified by subtracting the project emissions for that reporting period (PE) from the baseline emissions for that reporting period (BE) and applying an uncertainty deduction (UD) using Equation 5.39.

(b) Abandoned underground mine methane recovery activities that meet the following conditions are not subject to an uncertainty deduction and should calculate GHG emission reductions for a reporting period (ER) using an uncertainty deduction (UD) equal to 1:

(1) The project uses hyperbolic decline curve coefficients derived from mine-specific data measured from pre-exisiting wells or boreholes open to the atmosphere according to the provisions of section 5.4.1(s); or

(2) The project extracts methane exclusively from mines that utilized methane drainage systems when active.

Equation 5.39: GHG Emission Reductions

$ER = (BE - PE) \times UD$

Where,

ER	=	Emission reductions achieved by the project during the reporting period (tCO_2e)
BE	=	Baseline emissions during the reporting period (tCO_2e)
PE	=	Project emissions during the reporting period (tCO_2e)
UD	=	Uncertainty deduction; UD = 0.8 if using default hyperbolic decline curve coefficients and the mine did not utilize a methane drainage system when active, UD = 1 if using default hyperbolic decline curve coefficients and the abandoned mine utilized a methane drainage system when active, UD = 1 if using hyperbolic decline curve coefficients derived from measured data from pre-existing wells or boreholes open to the atmosphere

§ 5.4.1 Quantifying Baseline Emissions.

(a) Baseline emissions for a reporting period (BE) must be estimated by summing the baseline emissions for all SSRs identified as included in the baseline in Table 4.4 and using Equation 5.40.

(b) The emission reductions in any given reporting period must be equal to or less than the baseline emissions for that reporting period.

Equation 5.40: Baseline Emissions

$BE = BE_{MD} + BE_{MR}$

Where,

BE	=	Baseline emissions during the reporting period (tCO_2e)
BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)

(c) Baseline emissions from the destruction of AMM (BE_{MD}) must be quantified using Equations 5.41 and 5.42.

(d) BE_{MD} must include the estimated CO_2 emissions from the destruction of AMM in non-qualifying devices.

(e) Mine gas (MG) can originate from four distinct sources for abandoned underground mine methane recovery activities: pre-mining surface wells drilled into the mine during active mining operations, pre-mining in-mine boreholes drilled into the mine during active mining operations, post-mining gob wells drilled into the mine during active mining operations, and newly drilled surface wells. MG from these sources must be measured and accounted for individually per the equations in this section.

(f) For each eligible methane source, the volume or mass of MG that would have been sent to a non-qualifying device for destruction during the reporting period in the baseline must be the determined by calculating and comparing:

(1) The volume or mass of MG captured and sent to non-qualifying devices during the reporting period, adjusted for temperature and pressure using Equation 5.51, if applicable; and

(2) The volume of MG captured and sent to non-qualifying devices during the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than three years), adjusted for temperature and pressure using Equation 5.51, if applicable and averaged according to the length of the reporting period.

(3) The volume or mass of MG sent to non-qualifying devices during the time period a law, regulation, or legally binding mandate, in place for less than

three years prior to offset project commencement, was in effect, adjusted for temperature and pressure using Equation 5.51, if applicable, and averaged according to the length of the reporting period.

(g) For each methane source, the largest of the three above quantities must be used in Equation 5.42.

(h) If using a quantity from calculation (2) or (3) above and the project does not have data on the concentration of the methane to use in Equation 5.42, the highest single-day average methane concentration measured for that methane source during the reporting period must be used in its place.

(i) For the purpose of baseline quantification, only non-qualifying devices that were operating during the year prior to offset project commencement should be taken into account.

(j) If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

Equation 5.41: Baseline Emissions from Destruction of Methane

$BE_{MD} = MD_{B,i} \times CEF_{CH4}$

Where,

BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.)
$MD_{B,i}$	=	Methane destroyed by non-qualifying devices through use i during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

(k) The amount of mine methane destroyed ($MD_{B,i}$) must be quantified using Equation 5.42.

(l) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.42: Methane Destroyed in Baseline

$$MD_{B,i} = \sum_i MM_{B,i} \times DE_i$$

Where,

$MD_{B,i}$	=	Methane destroyed by use i during the reporting period (tCH_4)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by non-qualifying devices
$MM_{B,i}$	=	Methane measured sent to use i during the reporting period corrected to standard conditions, if applicable, for pressure and temperature; calculated separately for each device (tCH_4)
DE_i	=	Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

With:

$$MM_{B,i} = \sum_i (PSW_{B,i} \times C_{CH4} + PIB_{B,i} \times C_{CH4} + PGW_{B,i} \times C_{CH4} \times NSW_{B,i} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{B,i}$	=	Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)
$PIB_{B,i}$	=	Volume of MG from pre-mining in-mine boreholes sent to non-qualifying devices for destruction through use i during the reporting period (scf)
$PGW_{B,i}$	=	Volume of MG from post-mining gob wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)
$NSW_{B,i}$	=	Volume of MG from newly drilled surface wells sent to non-qualifying devices for destruction through use i during the reporting period (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$ = Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)

DV_t = Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(m) Baseline emissions from the release of methane (BE_{MR}) must be quantified using Equations 5.43 and 5.44. Calculations include the application of a hyperbolic emissions rate decline curve. The function is directly related the gassiness of the mine, which is reflective of physical parameters of the coal mine such as the mine size, gas content of the coal, permeability of the coal to the flow of gas.

(n) The decline curve estimates the emission rate of an abandoned mine over time by taking into account the time elapsed since mine closure, the average methane emission rate calculated using available data collected by MSHA over the life of the mine, and whether the mine is sealed or venting. The decline curve for a given mine is initialized at the date of abandonment and extrapolated through the crediting period.

(o) The amount of AMM released (tCH_4) must be determined by calculating and comparing:

(1) The emissions of methane for that reporting period calculated by the decline curve using Equation 5.44; and

(2) The quantity of methane destroyed by qualifying and non-qualifying devices during that reporting period calculated using Equation 5.49.

(p) The lesser of the two above quantities must be used in Equation 5.43

(q) AMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 5.43: Baseline Emissions from Release of Methane

$$BE_{MR} = \left[\min\left(AMM_{DC}, \sum_i MD_{B,i}\right) - \sum_i MD_{B,i}\right] \times GWP_{CH4}$$

Where,

BE_{MR}	=	Baseline emissions from release of methane into the atmosphere avoided by the project during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices
AMM_{DC}	=	Emissions of methane during the reporting period as calculated by the decline curve (tCH_4)
$MD_{P,i}$	=	Methane sent to all qualifying and non-qualifying devices for destruction through use i during the reporting period (tCH_4)
$MD_{B,i}$	=	Methane sent to non-qualifying devices for destruction through use i during the reporting period (tCH_4)
GWP_{CH4}	=	Global warming potential of methane (tCO_2e/tCH_4)

Equation 5.44: Methane Emissions Derived from the Hyperbolic Emission Rate Decline Curve

AMM_{DC} = $ER_{AMM} \times S \times (1 + b \times D_i \times t)^{\left(\frac{-1}{b}\right)} \times RP_{days} \times 0.0423 \times 0.000454$

Where,

AMM_{DC}	=	Emissions of methane from the decline curve during the reporting period (tCH_4)
ER_{AMM}	=	Average methane emission rate over the life of the mine (mscf/d)
S	=	Default effective degree of sealing; S = 1 for venting mines and 0.5 for sealed mines
b	=	Dimensionless hyperbolic exponent
D_i	=	Initial decline rate (1/day)
t	=	Time elapsed from the date of mine closure to midpoint of the reporting period (days)
RP_{days}	=	Days in reporting period
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

(r) The decline curve relies upon hyperbolic decline curve coefficients. Offset Project Operators or Authorized Project Designees may elect to:

(1) use the default hyperbolic decline curve coefficients presented in Table 5.1 based upon whether the mine is venting or sealed; or

Table 5.1: Default Hyperbolic Decline Curve Coefficients

Variable	Venting	Sealed
b	1.886581	2.016746
D_i (1/day)	0.003519	0.000835

(2) use hyperbolic decline curve coefficients derived from measured data from pre-existing wells or boreholes open to the atmosphere that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default hyperbolic decline curve coefficients upon written approval by the Executive Officer.

(s) To derive hyperbolic emission rate decline curve coefficients using measured data from pre-existing wells or boreholes open to the atmosphere an Offset Project Operator or Authorized Project Designee must do the following:

(1) Obtain average methane emission rate calculated using available data collected by MSHA over the life of the mine.

(2) After mine closure, three parameters must be monitored:

(A) MG flow rates;

(B) local barometric pressure; and

(C) methane concentration of MG

(3) Measurements must be of natural flow only with no assist from vacuum pumps or compressors.

(4) If gas flow metering equipment does not internally correct for temperature and pressure, apply Equation 5.45 to the flow rate of mine gas venting from pre-existing wells or boreholes open to the atmosphere

Equation 5.45: Emissions Rate Corrected for Temperature and Pressure

$$ERcorrected,y = ER_{meas,y} \times \frac{520}{T_{MGy}} \times \frac{P_{MG,y}}{1}$$

Where,

$ER_{corrected,y}$	=	Emissions rate of MG venting from pre-existing wells or boreholes open to the atmosphere during time interval y adjusted to 60°F and 1 atm (scf/unit of time)
$ER_{meas,y}$	=	Measured emission rate of MG venting from pre-existing wells or boreholes open to the atmosphere during time interval y (scf/unit of time)
$T_{MG,y}$	=	Measured temperature of the MG for the time interval y, °R=°F+460 (°R)
$P_{MG,y}$	=	Measured pressure of the MG for the time interval y (atm)

(5) The monitored data must be used to develop a correlation between barometric pressure and methane flow rate. Annual average barometric pressure at the site must then be used to normalize the annual methane flow rate.

(6) This normalized flow rate must then be plotted against the time since mine closure in order to derive the hyperbolic emission rate decline curve by fitting the data to a curve in the form of Equation 5.44.

§ 5.4.2. Quantifying Project Emissions.

(a) Project emissions must be quantified on an annual basis.

(b) Project emissions for a reporting period (PE) must be quantified by summing the emissions for all SSRs identified as included in the project in Table 4.4 and using Equation 5.46.

(c) AMM that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios.

Equation 5.46: Project Emissions

$PE = PE_{EC} + PE_{MD} + PE_{UM}$

Where,

PE	=	Project emissions during the reporting period (tCO_2e)
PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period (tCO_2e)

(d) If the project uses fossil fuel or grid electricity to power additional equipment required for project activities, the resulting CO_2 emissions from the energy consumed to capture and destroy methane (PE_{EC}) must be quantified using Equation 5.47.

(e) If the total electricity generated by project activities is greater than the additional electricity consumed for the capture and destruction of methane, then the $CONS_{ELEC}$ term may be omitted from Equation 5.47.

Equation 5.47: Project Emissions from Energy Consumed to Capture and Destroy Methane

$$PE_{EC} = (CONS_{ELEC} \times CEF_{ELEC}) + \frac{(CONS_{HEAT} \times CEF_{HEAT} + CONS_{FF} \times CEF_{FF})}{1000}$$

Where,

PE_{EC}	=	Project emissions from energy consumed to capture and destroy methane during the reporting period (tCO_2e)
$CONS_{ELEC}$	=	Additional electricity consumption for the capture and destruction of methane during the reporting period (MWh)
CEF_{ELEC}	=	CO_2 emission factor of electricity used from Appendix A (tCO_2e/MWh)
$CONS_{HEAT}$	=	Additional heat consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{HEAT}	=	CO_2 emission factor of heat used from Appendix A (kg CO_2/volume)
$CONS_{FF}$	=	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period (volume)
CEF_{FF}	=	CO_2 emission factor of fossil fuel used from Appendix A (kg CO_2/volume)
1/1000	=	Conversion of kg to metric tons

(f) Project emissions from the destruction of methane (PE_{MD}) must be quantified using Equations 5.48 and 5.49.

Equation 5.48: Project Emissions from Destruction of Captured Methane

$$PE_{MD} = \sum_{i} MD_{P,i} \times CEF_{CH4}$$

Where,

PE_{MD}	=	Project emissions from destruction of methane during the reporting period (tCO_2e)

i	=	Use of methane (flaring, power generation, heat generation production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices
$MD_{P,i}$	=	Methane destroyed by qualifying and non-qualifying devices through use i during the reporting period (tCH_4)
CEF_{CH4}	=	CO_2 emission factor for combusted methane (2.75 tCO_2e/tCH_4)

(g) The amount of mine methane destroyed ($MD_{P,i}$) must be quantified using Equation 5.49.

(h) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.49: Methane Destroyed

$$MD_{P,i} = \sum_{i} MM_{P,i} \times DE_i$$

Where,

$MD_{P,i}$	=	Methane destroyed by qualifying and non-qualifying devices through use i during the reporting period (tCH_4)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline, etc.) by all qualifying and non-qualifying devices
$MM_{P,i}$	=	Methane measured sent to qualifying and non-qualifying devices for destruction through use i during the reporting period corrected to standard conditions, if applicable, for pressure and temperature; calculated separately for each device (tCH_4)
DE_i	=	Efficiency of methane destruction device i, either site-specific or from Appendix B (%)

With:

$$MM_{P,i} = \sum_{i} (PSW_{P,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + PGW_{P,i} \times C_{CH4} + NSW_{P,i} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{P,i}$	=	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period.
$PIB_{P,i}$	=	Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PGW_{P,i}$	=	Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$NSW_{P,i}$	=	Volume of MG from newly drilled surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$	=	Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
DV_t	=	Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(i) Project emissions from uncombusted methane (PE_{UM}) must be quantified using Equation 5.50.

(j) Offset Project Operators and Authorized Project Designees may choose to use default methane destruction efficiencies (DE_i) provided in Appendix B or site-specific methane destruction efficiencies. Site-specific methane destruction

efficiencies that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the default methane destruction efficiencies may be used upon written approval by the Executive Officer.

Equation 5.50: Uncombusted Methane Emissions

$$PE_{UM} = \sum_{i} MM_{P,I} \times (1 - DE_I) \times GWP_{CH4}$$

Where,

PE_{UM}	=	Project emissions from uncombusted methane during the reporting period (tCO_2e)
i	=	Use of methane (flaring, power generation, heat generation, production of transportation fuel, injection into natural gas pipeline etc.) by all qualifying and non-qualifying devices
$MM_{P,I}$	=	Methane measured sent to qualifying and non-qualifying devices for destruction through use i during the reporting period; calculated separately for each device (tCH_4)
DE_I	=	Efficiency of methane destruction device i, either site-specific or from Appendix B (%)
GWP_{CH4}	=	Global warming potential of methane (tCO_2e/tCH_4)

With:

$$MM_{P,i} = \sum_{i} (PSW_{P,i} \times C_{CH4} + PIB_{P,i} \times C_{CH4} + PGW_{P,i} \times C_{CH4} + NSW_{P,I} \times C_{CH4}) \times 0.0423 \times 0.000454$$

Where,

$PSW_{P,i}$	=	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PIB_{P,i}$	=	Volume of MG from pre-mining in-mine boreholes sent to by qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$PGW_{P,i}$	=	Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)
$NSW_{P,i}$	=	Volume of MG from newly drilled surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period (scf)

C_{CH4}	=	Weighted average of measured methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)
0.0423	=	Density of methane (lb CH_4/scf CH_4)
0.000454	=	tCH_4/lb CH_4

With:

$$C_{CH4} = \frac{\sum_t DV_t \times C_{CH4,t}}{\sum_t DV_t}$$

Where,

$C_{CH4,t}$ = Daily average methane concentration of mine gas captured from methane source; calculated separately for each methane source (scf CH_4/scf)

DV_t = Daily volume of mine gas sent to destruction device; calculated separately for each methane source (scf/day)

If a thermal mass flow meter is used to monitor gas flow instead of a volumetric flow meter, the volume and density terms must be replaced by the monitored mass value and the methane concentration must be in mass percent.

(k) If gas flow metering equipment does not internally correct for temperature and pressure, use Equation 5.51 to determine the amount of mine gas sent to each qualifying and non-qualifying device during the reporting period.

Equation 5.51: MG Corrected for Temperature and Pressure

$$MG_{corrected,i,y} = MG_{meas,i,y} \times \frac{520}{T_{MGy}} \times \frac{P_{MG,y}}{1}$$

Where,

$MG_{corrected,i,y}$	=	Corrected flow rate or total volume of MG collected for the time interval y at utilization type i, adjusted to 60°F and 1 atm (scf/unit of time)
$MG_{meas,i,y}$	=	Measured flow rate or total volume of MG collected for the time interval y at utilization type i (scf/unit of time)
$T_{MG,y}$	=	Measured temperature of the MG for the time interval y, °R=°F+460 (°R)
$P_{MG,y}$	=	Measured pressure of the MG for the time interval y (atm)

Chapter 6. Monitoring

§ 6.1. General Monitoring Requirements.

(a) The Offset Project Operators or Authorized Project Designees is responsible for monitoring the performance of the offset project and operating each component of the collection and destruction system(s) in a manner consistent with the manufacturer's specifications.

(b) Operational activity of the methane drainage and ventilation systems and the destruction devices must be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational.

(1) For flares, operation is defined as thermocouple readings above 500°F.

(2) For all other destruction devices, the Offset Project Operator or Authorized Project Designee must demonstrate the destruction device was operational, and this demonstration is subject to the review and verification of an ARB-approved third party offset project verification body.

(c) If gas flow metering equipment does not internally correct for temperature and pressure, flow data must be corrected according to the appropriate quantification methodologies in Chapter 5.

(d) If a project uses elevated amounts of atmospheric gases in extracted mine gas as evidence of a pre-mining well being mined through, nitrogen and oxygen concentrations must be determined for each well at the time of offset project commencement and when the Offset Project Operator or Authorized Project Designee reports a pre-mining well as eligible. Gas samples must be collected by a third-party technician and amounts of nitrogen and oxygen concentrations determined by a full gas analysis using a chromatograph at an ISO 17025 accredited lab or a lab that has been certified by accreditation body conformant with ISO 17025 to perform test methods appropriate for atmospheric gas content analysis.

(e) Data substitution is allowed for limited circumstances where a project encounters flow rate or methane concentration data gaps. Offset Project Operators or Authorized Project Designees may apply the data substitution methodology

provided in Appendix C. No data substitution is permissible for data gaps resulting from inoperable equipment that monitors the proper functioning of destruction devices and no emission reductions will be credited under such circumstances.

§ 6.2. Instrument QA/QC.

Instruments and equipment used to monitor the destruction of mine methane or the temperature and pressure used to correct data measurements to STP must be inspected, cleaned and calibrated according to the following:

(a) All gas flow meters and methane analyzers must be:

(1) cleaned and inspected on a quarterly basis, with the activities performed and "as found/as left condition" of the equipment documented;

(2) field checked by a trained professional for calibration accuracy with the percent drift documented, using either a portable instrument (such as a pitot tube) or manufacturer specifications, no more than 24 hours after and up to two months prior to the end date of the reporting period; and

(3) calibrated by the manufacturer or a certified calibration service per manufacturer's specifications or every 5 years, whichever is more frequent.

(b) Additionally, flow meter calibrations must be documented to show that the meter was calibrated and methane analyzer calibrations must be documented to show that the calibration was carried out to the range of conditions (temperature and pressure) corresponding to the range of conditions as measured at the mine.

(c) If the field check on a piece of equipment reveals accuracy outside of a +/- 5% threshold, calibration by the manufacturer or a certified service provider is required for that piece of equipment.

(d) For the interval between the last successful field check and any calibration event confirming accuracy below the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure. These adjustments must be made for the entire period from the last successful field check until such time as the meter is properly calibrated.

(1) For calibrations that indicate the flow meter was outside the +/- 5% accuracy threshold, the project developer shall estimate total emission reductions using

(A) the metered values without correction; and

(B) the metered values adjusted based on the greatest calibration drift recorded at the time of calibration.

(e) The lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate. Data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check.

(f) If a portable instrument is used (such as a handheld methane analyzer), the portable instrument must be calibrated according to manufacturer's specification prior to each use.

§ 6.3. Document Retention.

(a) The Offset Project Operator or Authorized Project Designee is required to keep all documentation and information outlined in the Regulation and this protocol. Record retention requirements are set forth in section 95976 of the Regulation.

(b) Information that must be retained by the Offset Project Operator or Authorized Project Designee must include:

(1) All data inputs for the calculation of the project baseline emissions and project emission reductions;

(2) Emission reduction calculations;

(3) Mine operating permits, leases (if applicable), and air, water and land use permits;

(4) Notices of Violations (NOVs), and any administrative or legal consent orders related to project activities dating back at least three years prior to offset project commencement and for each year of project operation;

(5) Copies of mine plans and mine ventilation plans submitted to MSHA throughout the project life;

(6) Gas flow meter information (model number, serial number, manufacturer's calibration procedures);

(7) Methane analyzer information (model number, serial number, calibration procedures);

(8) Cleaning and inspection records for all gas meters;

(9) Field check results for all gas meters and methane analyzers;

(10) Calibration results for all gas meters and methane analyzers;

(11) Corrective measures taken if meter does not meet performance specifications;

(12) Gas flow data (for each flow meter);

(13) Methane concentration monitoring data;

(14) Gas temperature and pressure readings (only if flow meter does not correct for temperature and pressure automatically);

(15) Destruction device information (model numbers, serial numbers, installation date, operation dates);

(16) Destruction device monitoring data (for each destruction device);

(17) All maintenance records relevant to the methane collection and/or destruction device(s) and monitoring equipment;

(18) If using a calibrated portable gas analyzer for CH_4 content measurement the following records must be retained:

(A) Date, time, and location of methane measurement;

(B) Methane content of biogas (% by volume or mass) for each measurement;

(C) Methane measurement instrument information (model number and serial number);

(D) Date, time, and results of instrument calibration; and

(E) Corrective measures taken if instrument does not meet performance specifications

§ 6.4. Active Underground Mine Ventilation Air Methane Activities.

(a) The total inlet flow entering the destruction device must be measured continuously and recorded every two minutes to calculate average flow per hour.

(b) The methane concentration of the ventilation air entering the destruction device and of the exhaust gas must be measured continuously and recorded every two minutes to calculate average methane concentration per hour.

(c) If required in order to standardize the flow rate, volume or mass of VAM, the temperature and pressure in the vicinity of the flow meter must be measured continuously and recorded at least every hour to calculate hourly pressure and temperature.

(d) Offset Project Operators and Authorized Project Designees must monitor the parameters prescribed in Table 6.1.

Table 6.1. Active Underground Mine VAM Activity Monitoring Parameters – Quantification Methodology

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c), Measured (m), or Operating Records (o)	Comment
5.4 5.5	$VAM_{B,i}$	Volume of VAM that would have been sent to a non-qualifying device for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.1.1(d)
5.4 5.5 5.9	$C_{CH4,t}$	Hourly average methane concentration of ventilation air sent to destruction device	scf CH_4 / scf	Continuously	c,m	Readings taken every two minutes to calculate average methane concentration per hour
5.4 5.5 5.9	$VAM_{flow,t}$	Hourly average flow of ventilation air sent to destruction device	(scf/hour)	Continuously	c,m	Readings taken every two minutes to calculate average flow per hour
5.4 5.9 5.10	$VAM_{FLOW,y}$	Average flow rate of ventilation air entering the destruction device during period y corrected to	scfm	Continuously	m, c	Readings taken every two minutes to calculate average hourly flow; adjusted if

		standard conditions, if applicable, for inlet flow gas pressure and temperature				applicable using Equation 5.11
5.4 5.9 5.10	$TIME_y$	Time during which the destruction device is operational during period y	m	Continuously	m	
5.4 5.9 5.10	$C_{CH4,exhaust,t}$	Hourly average methane concentration of ventilation air in ventilation air exhaust	scf CH_4 / scf	Continuously	m, c	Readings taken every two minutes (either average over two minutes or instantaneous) to calculate average methane concentration per hour
5.5	$VAM_{P,j}$	Volume of ventilation air sent to qualifying and non-qualifying devices for destruction through use i during the project during the reporting period	scf	Continuously	m	Adjusted if applicable using Equation 5.11
5.5 5.9	$MG_{SUPP,i}$	Volume of mine methane extracted from a methane drainage system and sent to destruction device with	scf	Every reporting period	m	Adjusted if applicable using Equation 5.11
5.5 5.9	$C_{CH4,MG,t}$	Hourly average methane concentration of mine gas sent to destruction device	(scf CH_4/scf)	Continuously	m, c	Readings taken every 15 minutes to calculate average methane concentration per day
5.5 5.9	$DV_{MG,t}$	Daily volume of mine gas sent with ventilation air to destruction device	(scf /day)			Readings taken every 15 minutes to calculate average flow

						per day.
5.7	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	o	From electricity use records
5.7	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From purchased heat records
5.7	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From fuel use records
5.11	$VAM_{FLOWmeas,y}$	Uncorrected average flow rate of ventilation air entering the destruction device as measured during period y	scf/unit of time	Continuously	m, c	Readings taken every two minutes to calculate average hourly flow; adjusted, if applicable, to $VAM_{FLOW,y}$ using Equation 5.11
5.11	$T_{VAMinflow,y}$	Measured temperature of ventilation air entering the destruction device for the time period y, °R=°F+460	°R	Continuously	m, c	Readings taken at least every hour to calculate hourly temperature
5.11	$P_{VAMinflow,y}$	Measured pressure of ventilation air entering the destruction device for the time period y	atm	Continuously	m, c	Readings taken at least every hour to calculate hourly pressure

§ 6.5. Active Underground Mine Methane Drainage Activities.

(a) Mine gas from each methane source (i.e., pre-mining surface wells, pre-mining in-mine boreholes, or post-mining gob wells) must be monitored separately prior to interconnection with other MG sources. The volumetric or mass gas flow,

methane concentration, temperature, and pressure must be monitored and recorded separately for each methane source.

(b) Mine gas from each methane source (i.e., pre-mining surface wells, pre-mining in-mine boreholes, or post-mining gob wells) must be measured continuously. Offset Project Operators must record the mine gas flow rate every 15 minutes, adjusted for temperature and pressure, and record the totalized mine gas volume or mass at least daily, adjusted for temperature and pressure.

(c) Mine gas delivered to a destruction device must be measured continuously. Offset Project Operators must record the mine gas flow rate every 15 minutes, adjusted for temperature and pressure, and record the totalized mine gas volume or mass at least daily, adjusted for temperature and pressure. The flow of gas to each destruction device must be monitored separately for each destruction device, unless:

(1) a project consists of destruction devices that are of identical efficiency and verified to be operational throughout the reporting period; then a single flow meter may be used to monitor gas flow to all destruction devices; or

(2) a project consists of destruction devices that are not of identical efficiency, in which case the destruction efficiency of the least efficient destruction device must be used as the destruction efficiency for all destruction devices monitored by that meter.

(d) If a project using a single meter to monitor gas flow to multiple destruction devices has any periods of time when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods of time will only be eligible provided that the offset verifier can confirm all of the following requirements and conditions are met:

(1) The destruction efficiency of the least efficient downstream destruction device in operation must be used as the destruction efficiency for all destruction devices downstream of the single meter; and

(2) All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual

intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and

(3) For any period of time during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

(e) The methane concentration of the mine gas extracted from each methane source must be measured continuously, recorded every 15 minutes and averaged at least daily.

(f) If required in order to adjust the flow rate, volume, or mass of mine gas, the temperature and pressure of the mine gas from each methane source must be measured continuously and recorded at least every hour to calculate hourly temperature and pressure.

(g) Offset Project Operators and Authorized Project Designees must monitor the parameters prescribed in Table 6.2.

Table 6.2. Active Underground Mine Methane Drainage Activity Monitoring Parameters – Quantification Methodology

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c), Measured (m), Operating Records (o), Reference (r)	Comment
5.15 5.21 5.22	DE_i	Efficiency of methane destruction device i	%	Annually	r or m	Default methane destruction efficiencies provided in Appendix B or site-specific methane destruction efficiencies approved by the Executive Officer

5.15 5.16	$PSW_{B,i}$	Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.2.1(e).
5.15 5.16	$PIB_{B,i}$	Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.2.1(e)
5.15 5.16	$PGW_{B,i}$	Volume of MG from post-mining gob wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.2.1(e)
5.15 5.21 5.22	$C_{CH4,t}$	Hourly average methane concentration of mine gas sent to destruction device	(scf CH_4/scf)	Continuously	m, c	Readings taken every 15 minutes to calculate average methane concentration per day
5.15 5.21 5.22	DV_t	Daily volume of mine gas sent to destruction device	(scf /day)			Readings taken every 15 minutes to calculate average flow per day.

5.16 5.21 5.22	$PIB_{P,i}$	Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.23
5.16 5.21 5.22	$PGW_{P,i}$	Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.23
5.16	$PSWnqd_i$	Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.23
5.16 5.21 5.22	$MG_{SUPP,i}$	Volume of mine methane extracted from a methane drainage system and combusted with VAM	scf	Every reporting period	m	Adjusted if applicable using Equation 5.23
5.16 5.21 5.22	$C_{CH4,MG,t}$	Hourly average methane concentration of mine gas sent to destruction device	(scf CH_4/scf)	Continuously	m, c	Readings taken every 15 minutes to calculate average methane concentration per day
5.16 5.21 5.22	$DV_{MG,t}$	Daily volume of mine gas sent with ventilation air to destruction device	(scf /day)			Readings taken every 15 minutes to calculate average flow per day.

5.17	$PSWe_{pre,i}$	Volume of MG destroyed by qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from pre-mining surface wells that were mined through during the current reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.23
5.17	$PSWe_{post,i}$	Volume of MG destroyed by qualifying destruction devices in the current reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.23
5.19	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	o	From electricity use records
5.19	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From purchased heat records
5.19	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From fuel use records

5.21 5.22	$PSW_{P,all,i}$	Volume of MG from pre-mining surface wells captured and destroyed by qualifying and non-qualifying devices through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.23
5.23	$MG_{meas,i,y}$	Measured volume of MG collected for the time interval y at utilization type i	(scf/unit of time)	Continuously	m	Adjusted, if applicable, to STP using Equation 5.23
5.23	$T_{MG,y}$	Measured temperature of MG for the time interval y, °R=°F+460	°R	Continuously	m, c	Readings taken at least every hour to calculate temperature for time interval y
5.23	$P_{MG,y}$	Measured pressure of MG for the time interval y	atm	Continuously	m, c	Readings taken at least every hour to calculate temperature for time interval y

§ 6.6. Active Surface Mine Methane Drainage Activities.

(a) SMM from the drainage system must be measured continuously. Offset Project Operators must record the SMM flow rate every 15 minutes, adjusted for temperature and pressure, and record the totalized SMM volume or mass at least daily, adjusted for temperature and pressure.

(b) SMM delivered to a destruction device must be measured continuously. Offset Project Operators must record the SMM flow rate every 15 minutes, adjusted for temperature and pressure, and record the totalized SMM volume or mass at least daily, adjusted for temperature and pressure. The flow of gas to each destruction device must be monitored separately for each destruction device, unless:

(1) a project consists of destruction devices that are of identical efficiency and verified to be operational throughout the reporting period; then a single flow meter may be used to monitor gas flow to all destruction devices; or

(2) a project consists of destruction devices that are not of identical efficiency, in which case the destruction efficiency of the least efficient destruction device must be used as the destruction efficiency for all destruction devices monitored by that meter.

(c) If a project using a single meter to monitor gas flow to multiple destruction devices has any periods of time when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods of time will only be eligible provided that the offset verifier can confirm all of the following requirements and conditions are met:

(1) The destruction efficiency of the least efficient downstream destruction device in operation must be used as the destruction efficiency for all destruction devices downstream of the single meter; and

(2) All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and

(3) For any period of time during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

(d) The methane concentration of the SMM extracted from each methane source must be measured continuously, recorded every 15 minutes and averaged at least daily.

(e) If required in order to adjust the flow rate, volume, or mass of mine gas, the temperature and pressure of the SMM must be measured continuously and recorded at least every hour to calculate hourly temperature and pressure.

(f) Offset Project Operators and Authorized Project Designees must monitor the parameters prescribed in Table 6.3.

Table 6.3. Active Surface Mine Methane Drainage Activity Monitoring Parameters – Quantification Methodology

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c), Measured (m), Operating Records (o), Reference (r)	Comment
5.27 5.36 5.37	DE_i	Efficiency of methane destruction device i	%	Annually	r or m	Default methane destruction efficiencies provided in Appendix B or site-specific methane destruction efficiencies approved by the Executive Officer
5.27 5.28	$PSW_{B,i}$	Volume of MG from pre-mining surface wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.3.1(e).
5.27 5.28	$PIB_{B,i}$	Volume of MG from pre-mining in-mine boreholes that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.3.1(e).

5.27 5.28	$ECW_{B,i}$	Volume of MG from existing coalbed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.3.1(e).
5.27 5.28	$AWR_{B,i}$	Volume of MG from abandoned wells that are reactivated that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.3.1(e).
5.27 5.28	$CDW_{B,i}$	Volume of MG from converted dewatering wells that would have been sent to non-qualifying devices for destruction through use i during the reporting period in the baseline scenario	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.3.1(e).
5.27 5.28 5.36 5.37	$C_{CH4,t}$	Hourly average methane concentration of mine gas sent to destruction device	(scf CH_4/scf)	Continuously	m, c	Readings taken every 15 minutes to calculate average methane concentration per day

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5.27 5.28 5.36 5.37	DV_t	Daily volume of mine gas sent to destruction device	(scf /day)			Readings taken every 15 minutes to calculate average flow per day.
5.28	$PSW_{P,i}$	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.29 in accordance with sections 5.3.1(k), (l), and (m) must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.28 5.36 5.37	$PIB_{P,i}$	Volume of MG from pre-mining in-mine boreholes sent to qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.28	$ECW_{P,i}$	Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.27 in accordance with sections 5.3.1(k), (l), and (m) must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.28	$AWR_{P,i}$	Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.31 in accordance with sections 5.3.1(k), (l), and (m) must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.28	$CDW_{P,i}$	Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, only the eligible amount per Equation 5.29 in accordance with sections 5.3.1(k), (l), and (m) must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.28	$PSWnqd_i$	Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.28	$ECWnqd_i$	Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.28	$AWRnqd_i$	Volume of MG from abandoned wells that are reactivated sent to non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.28	$CDWnqd_i$	Volume of MG from converted dewatering wells sent to non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.29	$PSWe_{pre,i}$	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from pre-mining surface wells that were mined through during the current reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.29	$PSWe_{post,i}$	Volume of MG sent to qualifying destruction devices in the current reporting period captured from pre-mining surface wells that were mined through during earlier reporting periods	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.30	$ECWe_{pre,i}$	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during the current reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.30	$ECWe_{post,i}$	Volume of MG sent to qualifying destruction devices in the current reporting period captured from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining that were mined through during earlier reporting periods	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.31	$AWRe_{pre,i}$	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from abandoned wells that are reactivated that were mined through during the current reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.31	$AWRe_{post,i}$	Volume of MG sent to qualifying destruction devices in the current reporting period captured from abandoned wells that are reactivated that were mined through during earlier reporting periods	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.32	$CDWe_{pre,i}$	Volume of MG sent to qualifying destruction devices, from the offset project commencement date through the end of the current reporting period, captured from converted dewatering wells that were mined through during the current reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.32	$CDWe_{post,i}$	Volume of MG sent to qualifying destruction devices in the current reporting period captured from converted dewatering wells that were mined through during earlier reporting periods	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.34	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	o	From electricity use records
5.34	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From purchased heat records
5.34	$CONS_{FF}$	Additional fossil fuel consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From fuel use records
5.36 5.37	$PSW_{P,all,i}$	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.36 5.37	$ECW_{P,all,i}$	Volume of MG from existing coal bed methane wells that would otherwise be shut-in and abandoned as a result of encroaching mining sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.36 5.37	$AWR_{P,all,i}$	Volume of MG from abandoned wells that are reactivated sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38

5.36 5.37	$CDW_{P,all,i}$	Volume of MG from converted dewatering wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period. For qualifying devices, all MG, whether from a mined through well or not, must be quantified	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.38
5.38	$MG_{meas,l,y}$	Measured volume of MG collected for the time interval y at utilization type i	(scf/unit of time)	Continuously	m	Adjusted, if applicable, to STP using Equation 5.38
5.38	$T_{MG,y}$	Measured temperature of MG for the time interval y, °R=°F+460	°R	Continuously	m, c	Readings taken at least every hour to calculate temperature for time interval y
5.38	$P_{MG,y}$	Measured pressure of MG for the time interval y	atm	Continuously	m, c	Readings taken at least every hour to calculate temperature for time interval y

§ 6.7. Abandoned Underground Mine Methane Recovery Activities.

(a) AMM from the drainage system must be measured continuously. Offset Project Operators must record the AMM flow rate every 15 minutes, adjusted for temperature and pressure, and record the totalized mine gas volume or mass at least daily, adjusted for temperature and pressure.

(b) AMM delivered to a destruction device must be measured continuously. Offset Project Operators must record the AMM flow rate every 15 minutes, adjusted for temperature and pressure, and record the totalized mine gas volume or mass at least daily, adjusted for temperature and pressure. The flow of gas to each

destruction device must be monitored separately for each destruction device, unless:

(1) a project consists of destruction devices that are of identical efficiency and verified to be operational throughout the reporting period; then a single flow meter may be used to monitor gas flow to all destruction devices; or

(2) a project consists of destruction devices that are not of identical efficiency, in which case the destruction efficiency of the least efficient destruction device must be used as the destruction efficiency for all destruction devices monitored by that meter.

(c) If a project using a single meter to monitor gas flow to multiple destruction devices has any periods of time when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods of time will only be eligible provided that the offset verifier can confirm all of the following requirements and conditions are met:

(1) The destruction efficiency of the least efficient downstream destruction device in operation must be used as the destruction efficiency for all destruction devices downstream of the single meter; and

(2) All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and

(3) For any period of time during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

(d) The methane concentration of the MG extracted from each methane source must be measured continuously, recorded every 15 minutes and averaged at least daily.

(e) If required in order to adjust the flow rate, volume, or mass of AMM, the temperature and pressure of the AMM must be measured continuously and recorded at least every hour to calculate hourly temperature and pressure.

(f) Offset Project Operators or Authorized Project Designees that elect to derive mine-specific hyperbolic emission rate decline curve coefficients using measured data from pre-existing wells or boreholes open to the atmosphere must adhere to adhere to the following:

(1) Offset Project Operators and Authorized Project Designees must monitor the:

(A) MG flow rates;

(B) local barometric pressure; and

(C) methane concentration of MG

(2) Data must be monitored over a 72 hour period on at least three separate occasions each separated by a minimum of 90 days.

(3) MG flow rate and the barometric pressure must be monitored continuously and recorded at least on an hourly basis.

(4) Methane concentration must be measured at least daily.

(g) Offset Project Operators and Authorized Project Designees must monitor the parameters prescribed in Table 6.4.

Table 6.4. Abandoned Underground Mine Methane Recovery Activity Monitoring Parameters – Quantification Methodology

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c), Measured (m), Operating Records (o), Reference (r)	Comment
5.42 5.49 5.50	DE_i	Efficiency of methane destruction device i	%	Annually	r or m	Default methane destruction efficiencies provided in Appendix B or site-specific methane destruction efficiencies approved by the Executive

						Officer.
5.42	$PSW_{B,i}$	Volume of MG from pre-mining surface wells sent to non-qualifying devices for destruction through use i during the reporting period	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.4.1(f).
5.42	$PIB_{B,i}$	Volume of MG from pre-mining in-mine boreholes sent to non-qualifying devices for destruction through use i during the reporting period	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.4.1(f).
5.42	$PGW_{B,i}$	Volume of MG from post-mining gob wells sent to non-qualifying devices for destruction through use i during the reporting period	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.4.1(f).
5.42	$NSW_{B,i}$	Volume of MG from newly drilled surface wells sent to non-qualifying devices for destruction through use i during the reporting period	scf	Estimated at offset project commencement; calculated annually if non-qualifying device continues to operate after project start	c, m	The largest of the three values calculated per section 5.4.1(f).
5.42 5.49 5.50	$C_{CH4,t}$	Hourly average methane concentration of mine gas sent to destruction device	(scf CH_4/scf)	Continuously	m, c	Readings taken every 15 minutes to calculate average methane concentration per day
5.42 5.49 5.50	DV_t	Daily volume of mine gas sent to destruction device	(scf /day)			Readings taken every 15 minutes to calculate average flow per day.

5.44	ER_{AMM}	Average emission rate of AMM over the life of the mine calculated using available data collected by MSHA	scf/d	At offset project commencement	o	Available from MSHA
5.44	t	Time elapsed from the date of mine closure to midpoint of the reporting period	days	At offset project commencement	o	Available from public agency (i.e., MSHA, EPA, etc.)
5.44	RP_{days}	Days in reporting period	days	Annually	o	
5.45	$ER_{meas,y}$	Measured emission rate of MG venting from pre-existing wells or boreholes open to the atmosphere during time interval y	(scf/unit of time)	Continuously	m	Adjusted, if applicable, to STP using Equation 5.45
5.45 5.51	$T_{MG,y}$	Measured temperature of MG for the time interval y, °R=°F+460	°R	Continuously	m, c	Readings taken at least every hour to calculate temperature for time interval y
5.45 5.51	$P_{MG,y}$	Measured pressure of MG for the time interval y	atm	Continuously	m, c	Readings taken at least every hour to calculate temperature for time interval y
5.47	$CONS_{ELEC}$	Additional electricity consumption for the capture and destruction of methane during the reporting period	MWh	Every reporting period	o	From electricity use records
5.47	$CONS_{HEAT}$	Additional heat consumption for the capture and destruction of methane during the reporting period	Volume	Every reporting period	o	From purchased heat records
5.47	$CONS_{FF}$	Additional fossil fuel consumption	Volume	Every reporting period	o	From fuel use records

		for the capture and destruction of methane during the reporting period				
5.49 5.50	$PSW_{P,i}$	Volume of MG from pre-mining surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.51
5.49 5.50	$PIB_{P,i}$	Volume of MG from pre-mining in-mine boreholes sent to by qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.51
5.49 5.50	$PGW_{P,i}$	Volume of MG from post-mining gob wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.51
5.49 5.50	$NSW_{P,i}$	Volume of MG from newly drilled surface wells sent to qualifying and non-qualifying devices for destruction through use i during the reporting period	scf	Every reporting period	m	Adjusted, if applicable, to STP using Equation 5.51
5.51	$MG_{meas,i,y}$	Measured volume of MG collected for the time interval y at utilization type i	(scf/unit of time)	Continuously	m	Adjusted, if applicable, to STP using Equation 5.51
Monitoring Parameters for Deriving Mine-Specific Hyperbolic Emission Rate Decline Curve Coefficients						
Description			Data	Measurement	Calculated (c),	Comment

	Unit	Frequency	Measured (m)	
MG flow rate	(mscf/d)	Continuously	m, c	Recordings taken at least on an hourly basis during the monitoring period
Local barometric pressure	atm	Continuously	m	Recordings taken at least on an hourly basis during the monitoring period
Measured methane concentration of mine gas captured from methane source	scf CH_4/scf	Continuously	m	Readings taken at least daily during the monitoring period.

Chapter 7. Reporting

In addition to the offset project requirements set forth in sections 95975 and 95976 the Regulation, mine methane capture offset projects must adhere to the project listing and reporting eligibility requirements below.

§ 7.1. Listing Requirements.

(a) Listing information must be submitted by the Offset Project Operator or Authorized Project Designee no later than the date on which the Offset Project Operator or Authorized Project Designee submits the first Offset Project Data Report.

(b) In order for a mine methane capture Compliance Offset Project to be listed, the Offset Project Operator or Authorized Project Designee must submit the information required by section 95975 the Regulation, in addition to the following information:

(1) Offset project name.

(2) Mine methane capture activity type (i.e., active underground mine VAM activity, active underground mine methane drainage activity, active surface mine methane drainage activity, or abandoned underground mine methane recovery activity).

(3) Contact information including name, phone number, mailing address, physical address (if different from mailing address), and email address for the:

(A) Offset Project Operator; and

(B) Authorized Project Designee (if applicable).

(4) CITSS ID number for the:

(A) Offset Project Operator; and

(B) Authorized Project Designee (if applicable).

(5) Contact information including name, phone number, email address and, if applicable, the organizational affiliation for:

(A) the person submitting the information;

(B) technical consultants.

(6) Date of form completion.

(7) *Name and mailing address of mine owner(s) and parent company(ies), if different from owner.

(8) *Name and mailing address of surface owner(s), if different from mine owner.

(9) *Name and mailing address of mine methane owner(s), if different from mine owner.

(10) *Name and mailing address of mine operator(s), if different from mine owner.

(11) *Name and mailing address of methane destruction system owner(s), if different from mine owner.

(12) Other parties with a material interest in the mine methane.

(13) A description of the mine and resource ownership and operation structures.

(14) *Documentation (e.g., title report, coal lease, gas lease, etc.) showing the Offset Project Operator's legal authority to implement the offset project.

(15) *Physical address and latitude and longitude coordinates of mine site.

(16) *Indicate if the project occurs on private or public lands and further specify if the project occurs on any of the following categories of land:

(A) Land that is owned by, or subject to an ownership or possessory interest of a Tribe;

(B) Land that is "Indian lands" of a Tribe, as defined by 25 U.S.C. §81(a)(1); or

(C) Land that is owned by any person, entity, or Tribe, within the external borders of such Indian lands.

(17) *If the project is located on one the above categories of land, a description and copies of documentation demonstrating that the land is owned by (or subject to an ownership or possessory interest of) a tribe or private entities.

(18) *MSHA mine identification number.

(19) *MSHA classifications.

(A) coal or metal and nonmetal;

(B) underground or surface; and

(C) active or abandoned.

(20) Mine basin as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991).

(21) *Mining method(s) employed (e.g., longwall, room and pillar, open-pit, etc.).

(22) *Average annual mineral production (specify mineral produced and unit).

(23) *Year of initial production.

(24) *Year of closure (estimate if mine is not yet closed).

(25) Name of state and/or federal agency(ies) responsible for issuing mine leases and/or permits.

(26) List any permits obtained, or to be obtained, to build and operate the project.

(27) For active underground mine VAM activities, active underground mine methane drainage activities, and active surface mine methane drainage activities, up-to-date mine plan, mine ventilation plan, and mine map

submitted to MSHA and/or appropriate state or federal agency responsible for mine leasing/permitting.

(28) *For abandoned mine methane recovery activities, the final mine maps submitted to appropriate state or federal environmental or mining agencies upon closure.

(29) Offset project commencement date and specification of the action(s) that identify the commencement date.

(30) First reporting period.

(31) A qualitative characterization and quantitative estimate of the baseline emissions at the mine including an explanation of how the quantitative estimate was reached.

(32) Describe any mine methane destruction occurring at the mine prior to the offset project commencement date. List the source of the methane destroyed, destruction device(s) used, and device operation dates.

(33) A description of the project activities that will lead to GHG emission reductions including the methane end-use management option(s), destruction devices, and metering and data collection systems to be employed by the project.

(34) For active underground mine VAM activities, state whether supplemental methane will be used.

(35) Declaration that the project is not being implemented as a result of any federal, state or local law, statute, regulation, court order or other legally binding mandate.

(36) *Disclose if any GHG reductions associated with the offset project have ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing. Identify the registry or program as well as the vintage(s) of credits issued, reporting period(s), and verification bodies that have performed verification services.

(37) State whether the project is transitioning to the Compliance Offset Protocol Mine Methane Capture Projects, after previously being listed as an early action offset project.

(38) *List any programs participated in by the mine owner and operator, either in the past or present, that encourage the capture and destruction of mine methane. If applicable, include programs at mine locations other than the project site. Specify dates of participation for each program

(39) *Bird's-eye view map of the mine site that includes:

(A) Longitude and latitude coordinates.

(B) Governing jurisdictions.

(C) Public and private roads.

(D) Mine permit boundary.

(E) Mine lease boundary, if applicable.

(F) Location of existing ventilation shafts. For active underground mine VAM activities, indicate whether or not the shaft is part of the project.

(G) Planned location of additional ventilation shafts. For active underground mine VAM activities, indicate whether or not the shaft will be part of the project.

(H) Location of existing wells and boreholes. For active underground mine methane drainage activities, active surface mine methane drainage activities, and abandoned underground mine methane recovery activities, assign a number to each existing well/borehole and, on a separate sheet of paper, indicate:

1. the source type (i.e., pre-mining surface well, pre-mining in-mine borehole, post-mining gob well, existing coal bed methane (CBM) well that would otherwise be shut-in and abandoned, abandoned well that is re-activated, and converted dewatering wells);
2. whether or not the well/borehole is part of the project; and
3. for pre-mining surface wells, specify whether or not the well is mined through and when the well was, or is expected to be, mined through.

(I) Location of additional wells and boreholes planned to be drilled prior to offset project commencement. For active underground mine methane drainage activities, active surface mine methane drainage activities, and abandoned underground mine methane recovery activities, assign a number to each well/borehole and, on a separate sheet of paper, indicate:

1. the source type (i.e., pre-mining surface well, pre-mining in-mine borehole, post-mining gob well);
2. whether or not the well/borehole will be part of the project; and
3. for pre-mining surface wells, specify when the well is expected to be mined through.

(J) Location of existing equipment used to collect, treat, store, meter, and destroy mine methane. Assign a number to each piece of equipment and, on a separate sheet of paper, indicate:

1. the manufacturer and name of each piece of equipment;
2. the purpose of each piece of equipment;
3. the installation date of each piece of equipment;
4. for metering equipment, the date of the most recent inspection, cleaning and calibration of each piece of equipment;
5. for destruction devices, whether it is a qualifying or non-qualifying destruction device in accordance with Chapter 2;
6. for non-qualifying destruction devices that were operating at the mine prior to offset project commencement and during the year immediately preceding offset project commencement, provide the volume or mass of VAM/MM/SMM/AMM destroyed by the device in the three-year period prior to offset project commencement (or during the length of time the devices are operational, if less than

three years), averaged according to the length of the reporting period; and

7. for destruction devices that have been source-tested to develop site-specific device destruction efficiency, the date of the test and the resulting destruction efficiency.

(K) Location of additional equipment used to collect, treat, store, meter, and destroy mine methane planned to be installed prior to offset project commencement. Assign a number to each piece of equipment and, on a separate sheet of paper, indicate:

1. the manufacturer, name/model number, and serial number of each piece of equipment;
2. the purpose of each piece of equipment;
3. the expected installation date of each piece of equipment; and
4. for destruction devices, whether it is a qualifying or non-qualifying destruction device in accordance with Chapter 2.

(40) A geologic cross section diagram showing aboveground and underground conditions including:

(A) Mined and unmined coal seam(s) from the surface to 50 meters below the lowest mined seam.

(B) Underground mine extents according to an up-to-date mine plan.

(C) Include the well depth of completion relative to the lowermost mined seam.

(D) Mining progress indicating direction of mining.

(E) Aboveground mine boundary.

(F) For active underground mine VAM activities, all existing and planned ventilation shafts (labeled using the same numbering system as the map).

(G) For active underground mine methane drainage activities, active surface mine methane drainage activities and abandoned underground mine methane recovery activities, all existing and

planned wells/boreholes (labeled using the same numbering system as the map). Include the depth and angle of existing pre-mining surface wells.

(H) Existing and planned equipment used to collect, treat, store, meter, and destroy mine methane (labeled using the same numbering system as the map).

(c) Abandoned mine methane recovery activities that are comprised of multiple mines as allowed for by section 2.4 must provide the items marked with an asterisk (*) for each involved mine.

§ 7.2. Offset Project Data Report.

(a) Offset Project Operators or Authorized Project Designees must submit an Offset Project Data Report (OPDR) at the conclusion of each Reporting Period according to the reporting schedule in section 95976 of the Regulation.

(b) Offset Project Operators or Authorized Project Designees must submit the information required by section 95976 of the Regulation, in addition to the following information:

(1) Offset project name.

(2) Mine methane capture activity type (i.e., active underground mine VAM activity, active underground mine methane drainage activity, active surface mine methane drainage activity, or abandoned underground mine methane recovery activity).

(3) Contact information including name, phone number, mailing address, physical address (if different from mailing address), and email address for the:

(A) Offset Project Operator; and

(B) Authorized Project Designee (if applicable).

(4) CITSS ID number for the:

(A) Offset Project Operator; and

(B) Authorized Project Designee (if applicable).

(5) Contact information including name, phone number, email address and, if applicable, the organizational affiliation for:

(A) the person submitting the information;

(B) technical consultants.

(6) Date of form completion.

(7) Reporting period.

(8) Offset project commencement date.

(9) *Physical address and latitude and longitude coordinates of mine site.

(10) Mine basin as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG-CSD Geological Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laurie G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991).

(11) *Mining method(s) employed (e.g., longwall, room and pillar, open-pit, etc.).

(12) *Mineral production during reporting period (specify mineral produced and unit).

(13) Statement as to whether all the information submitted for project listing is still accurate. If not, provide updates to relevant listing information.

(14) *Statement as to whether the project has met all local, state, or federal regulatory requirements during the reporting period. If not, an explanation of the non-compliance must be provided.

(15) For active underground mine methane drainage activities and active surface mine methane drainage activities, latest mine plan and mine map submitted to appropriate state or federal agency responsible for mine leasing/permitting.

(16) For active underground mine VAM activities, state whether supplemental methane was used.

(17) Baseline emissions during the reporting period (BE), following the requirements of Chapter 5.

(18) Project emissions during the reporting period (PE), following the requirements of Chapter 5.

(19) A calculation of the total net GHG reductions for the reporting period (ER), following the requirements of Chapter 5.

(20) For each methane source:

(A) name the destruction device that captured methane was sent to;

(B) provide the amount of VAM or mine gas (MG) collected during the reporting period and the weighted average of methane concentration of the VAM/MG for the reporting period;

(C) provide the amount of methane (CH_4) sent to each qualifying destruction device during the reporting period;

(D) provide the amount of methane (CH_4) sent to each non-qualifying destruction device during the reporting period; and

(E) for pre-mining surface wells, indicate whether the well is mined through.

(21) For active underground mine methane drainage activities and active surface mine methane drainage activities, identify all pre-mining surface wells that were mined through during the reporting period in accordance with Chapter 5.

(22) For each qualifying and non-qualifying destruction device:

(A) provide the amount of methane destroyed during the reporting period; and

(B) indicate if the gas flow metering equipment for the device internally corrects for temperature and pressure

(23) Indicate whether the project used site-specific methane destruction efficiencies and, if so, provide a description of the process of establishing these destruction efficiencies that includes the identity of any third parties involved.

(24) Declaration that the project is not being implemented as a result of any federal, state or local law, statute, regulation, court order or other legally binding mandate.

(d) Abandoned mine methane recovery activities that are comprised of multiple mines as allowed for by section 2.4 must provide the items marked with an asterisk (*) for each involved mine.

Chapter 8. Verification

(a) All Offset Project Data Reports are subject to regulatory verification as set forth in section 95977 of the Regulation by an ARB accredited offset verification body.

(b) The Offset Project Data Reports must receive a positive or qualified positive verification statement to be issued ARB or registry offset credits.

Appendix A. Emission Factors – Quantification Methodology

Table A.1 CO_2 Emission Factors for Fossil Fuel Use

Fuel Type Coal and Coke	Default High Heat Value MMBtu / short ton	Default CO2 Emission Factor kg Co_2 / mmBtu	Default CO2 Emission Factor kg CO_2 / short ton
Anthracite	25.09	103.54	2597.819
Bituminous	24.93	93.40	2328.462
Subbituminous	17.25	97.02	1673.595
Lignite	14.21	96.36	1369.276
Coke	24.80	102.04	2530.592
Mixed (Commercial sector)	21.39	95.26	2037.611
Mixed (Industrial coking)	26.28	93.65	2461.122
Mixed (Electric Power sector)	19.73	94.38	1862.117
Natural Gas	**MMBtu / scf**	**kg CO_2 / mmBtu**	**kg CO_2 / scf**
(Weighted U.S. Average)	1.028×10^{-3}	53.02	0.055
Petroleum Products	**MMBtu/gallon**	**kg CO_2 / mmBtu**	**kg CO_2 / gallon**
Distillate Fuel Oil No. 1	0.139	73.25	10.182
Distillate Fuel Oil No. 2	0.138	73.96	10.206
Distillate Fuel Oil No. 4	0.146	75.04	10.956
Distillate Fuel Oil No. 5	0.140	72.93	10.210
Residual Fuel Oil No. 6	0.150	75.10	11.265
Used Oil	0.135	74.00	9.990
Kerosene	0.135	75.20	10.152
Liquefied petroleum gases (LPG)	0.092	62.98	5.794
Propane	0.091	61.46	5.593
Propylene	0.091	65.95	6.001
Ethane	0.069	62.64	4.322
Ethanol	0.084	68.44	5.749
Ethylene	0.100	67.43	6.743
Isobutane	0.097	64.91	6.296
Isobutylene	0.103	67.74	6.977
Butane	0.101	65.15	6.580
Butylene	0.103	67.73	6.976
Naphtha (<401 deg F)	0.125	68.02	8.503
Natural Gasoline	0.110	66.83	7.351
Other Oil (>401 deg F)	0.139	76.22	10.595
Pentanes Plus	0.110	70.02	7.702
Petrochemical Feedstocks	0.129	70.97	9.155
Petroleum Coke	0.143	102.41	14.645
Special Naphtha	0.125	72.34	9.043
Unfinished Oils	0.139	74.49	10.354
Heavy Gas Oils	0.148	74.92	11.088

Lubricants	0.144	74.27	10.695
Motor Gasoline	0.125	70.22	8.778
Aviation Gasoline	0.120	69.25	8.310
Kerosene-Type Jet Fuel	0.135	72.22	9.750
Asphalt and Road Oil	0.158	75.36	11.907
Crude Oil	0.138	74.49	10.280
Other fuels (solid)	**MMBtu / short ton**	**kg CO_2 / mmBtu**	**kg CO_2 / short ton**
Municipal Solid Waste	9.95[1]	90.7	902.465
Tires	26.87	85.97	2310.014
Plastics	38.00	75.00	2850.000
Petroleum Coke	30.00	102.41	3072.300
Other fuels (Gaseous)	**MMBtu / scf**	**kg CO_2 / mmBtu**	**kg CO_2 / scf**
Blast Furnace Gas	0.092×10^{-3}	274.32	0.025
Coke Oven Gas	0.599×10^{-3}	46.85	0.028
Propane Gas	2.516×10^{-3}	61.46	0.155
Fuel Gas[2]	1.388×10^{-3}	59.00	0.082
Biomass Fuels - Solid	**MMBtu / short ton**	**kg CO2 /mmBtu**	**kg CO_2 / short ton**
Wood and Wood Residuals	15.38	93.80	1442.644
Agricultural Byproducts	8.25	118.17	974.903
Peat	8.00	111.84	894.720
Solid Byproducts	25.83	105.51	2725.323
Biomass Fuels - Gaseous	**MMBtu / scf**	**kg CO2 / mmBtu**	**kg CO_2 / scf**
Biogas (Captured methane)	0.841 x 10-3	52.07	0.044
Biomass Fuels - Liquid	**MMBtu / gallon**	**kg CO2 / mmBtu**	**kg CO_2 / gallon**
Ethanol	0.084	68.44	5.749
Biodiesel	0.128	73.84	9.452
Rendered Animal Fat	0.125	71.06	8.883
Vegetable Oil	0.120	81.55	9.786

Table A.2 Emissions & Generation Resource Integrated Database (eGRID) Table

eGRID subregion acronym	eGRID subregion name	Annual output emission rates (lb CO_2/MWh)	(metric ton CO_2/MWH)*
AKGD	ASCC Alaska Grid	1,280.86	0.633
AKMS	ASCC Miscellaneous	521.26	0.257
AZNM	WECC Southwest	1,191.35	0.588
CAMX	WECC California	658.68	0.325
ERCT	ERCOT All	1,181.73	0.584
FRCC	FRCC All	1,176.61	0.581
HIMS	HICC Miscellaneous	1,351.66	0.668
HIOA	HICC Oahu	1,593.35	0.787
MORE	MRO East	1,591.65	0.786
MROW	MRO West	1,628.60	0.804
NEWE	NPCC New England	728.41	0.360
NWPP	WECC Northwest	819.21	0.405
NYCW	NPCC NYC/Westchester	610.67	0.302
NYLI	NPCC Long Island	1,347.99	0.666
NYUP	NPCC Upstate NY	497.92	0.246
RFCE	RFC East	947.42	0.468
RFCM	RFC Michigan	1,659.46	0.820
RFCW	RFC West	1,520.59	0.751
RMPA	WECC Rockies	1,824.51	0.901
SPNO	SPP North	1,815.76	0.897
SPSO	SPP South	1,599.02	0.790
SRMV	SERC Mississippi Valley	1,002.41	0.495
SRMW	SERC Midwest	1,749.75	0.864
SRSO	SERC South	1,325.68	0.655
SRTV	SERC Tennessee Valley	1,357.71	0.671
SRVC	SERC Virginia/Carolina	1,035.87	0.512
U.S.		**1,216.18**	**0.601**

*Converted from lbs CO2/MWh to metric tons CO2/MWH using using conversion factor 1 metric ton = 2,204.62lbs.

Appendix B. Device Destruction Efficiencies – Quantification Methodology

Table B.1 Default Destruction Efficiencies by Destruction Device

Biogas Destruction Device	Biogas Destruction Efficiency (BDE)
Open Flare	0.96
Enclosed Flare	0.995
Lean-burn Internal Combustion Engine	0.936
Rich-burn Internal Combustion Engine	0.995
Boiler	0.98
Microturbine or large gas turbine	0.995
Upgrade and use of gas as CNG/LNG fuel	0.95
Upgrade and injection into natural gas transmission and distribution pipeline	0.98

Equation B.1: Calculating Heat Generation Emission Factor

$$CEF_{heat} = \frac{CEF_{CO2,i}}{Eff_{heat}} \times \frac{44}{12}$$

Where,

CEF_{heat} = CO_2 emission factor for heat generation *12*

$CEF_{CO2,i}$ = CO_2 emission factor of fuel used in heat generation (see table B.1)

Eff_{heat} = Boiler efficiency of the heat generation (either measured efficiency, manufacturer nameplate data for efficiency, or 100%

$\frac{44}{12}$ = Carbon to carbon dioxide conversion factor

Appendix C. Data Substitution Methodology – Quantification Methodology

(a) ARB expects that MMC projects will have continuous, uninterrupted data for the entire reporting period. However, ARB recognizes that unexpected events or occurrences may result in brief data gaps.

(b) This appendix provides a quantification methodology to be applied to the calculation of GHG emission reductions for MMC projects when data integrity has been compromised due to missing data points.

(c) This methodology is only applicable to gas flow metering and methane concentration parameters. Data substitution is not allowed for equipment that monitors the proper functioning of destruction devices such as thermocouples.

(d) The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances.

(e) Data substitution is not allowed for data used to calculate mine specific hyperbolic decline curve coefficients for an abandoned underground mine methane recovery activity.

(f) Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited.

(g) Substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

(1) Proper functioning can be evidenced by thermocouple readings for flares or engines, energy output for engines, etc.

(2) For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.

(3) For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

(h) If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology may be applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours immediately before and following the outage
Six to 24 hours	Use the 90% lower confidence limit of the 24 hours prior to and after the outage
One to seven days	Use the 95% lower confidence limit of the 72 hours prior to and after the outage
Greater than one week	No data may be substituted and no credits may be generated

Appendix B:

Leakage Risk Analysis for New and Modified Sectors

What is Leakage Risk Analysis?

The California Cap-and-Trade Program was designed such that it would not unduly disadvantage California industry while achieving the emissions reduction goals set forth in the Global Warming Solutions Act of 2006 (AB 32). When introducing an environmental regulation within a jurisdiction, there is the possibility that production costs and prices in that jurisdiction increase relative to those costs in jurisdictions that do not introduce comparable regulations. This can precipitate a shift in demand away from goods produced in the implementing jurisdiction toward goods produced elsewhere. As a result, the reduction in production and emissions in the implementing jurisdiction may be offset by increased production and emissions elsewhere. This offsetting increase in emissions is called emissions leakage.[1] AB 32 directs the Air Resources Board (ARB) to design all greenhouse gas (GHG) regulations to minimize leakage to the extent feasible.[2]

Staff developed ARB's leakage risk analysis methodology in 2010 as part of the Cap-and-Trade Program. This allows for entities covered by the Cap-and-Trade Program to be categorized by leakage risk and receive industry assistance in the form of free allowances based in part on the entity's leakage risk classification. For a thorough understanding of the leakage risk analysis methodology, see Appendix K to the 2010 Cap-and-Trade regulation.[3]

Since that time there have been several new covered entities entering the program whose products are dissimilar enough from previous entrants that new leakage analysis must be performed for those new entrants. Further, there was one industrial sector which was previously analyzed for which newly public data has indicated a change in the leakage risk categorization for entities in that industrial sector. This document describes the leakage risk analysis that staff performed to properly categorize the leakage risk for these covered entities.

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[1] California Global Warming Solutions Act of 2006 (AB 32) HSC § 38505(j) http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.html.
[2] Ibid, § 38562(b)(8).
[3] California Air Resources Board (2010) Cap-and-Trade Regulation Initial Statement of Reasons (ISOR) Appendix K. http://www.arb.ca.gov/regact/2010/capandtrade10/capv4appk.pdf.

Industrial Sector Classification

In order to perform the leakage risk analysis for an entity, staff must first classify the entity by industrial sector in order to apply industrial economic data collected by the U.S. Census Bureau and other government agencies. Staff used the North American Industrial Classification System (NAICS) to group industrial activities at the 6 digit level disaggregation whenever possible, as this is the most disaggregated level of information commonly collected. Because some of the new entrants to the program do not fall under previously analyzed 6 digit level NAICS sectors, it was necessary for staff to perform new leakage analysis for the newly represented sectors. These new sectors include the following:

- 212299 - All Other Metal Ore Mining[4]
- 324121 - Asphalt Paving Mixture and Block Manufacturing
- 325193 - Ethyl Alcohol Manufacturing
- 332510 - Hardware manufacturing
- 336414 - Guided Missile and Space Vehicle Manufacturing
- 332112 - Nonferrous Forging

Further, this analysis includes one sector that was re-categorized due to newly available public data:

- 327993 - Mineral Wool Manufacturing

Leakage Risk Metrics

After determining the NAICS sector of a covered entity, two metrics are employed to determine leakage risk classification for an industrial sector: emissions intensity (EI) and trade exposure (TE).

The EI metric is used to measure the amount of GHG emissions generated per the value added for an industrial sector in the creation of its products:

$$EI = \text{metric tons } CO_2e \,/\, \$\text{million value added} \quad (1)$$

Emissions data is collected by ARB either through ARB's own mandatory reporting program (MRR) or from the Interagency Report on International Competitiveness and

[4] In this case, the analysis is specific to mining of rare earth metals due to uniqueness of the covered entity and lack of data for the overall sector.

Emission Leakage (IAR).[5] Value added data is taken from the U.S. Census Bureau's Annual Survey of Manufacturers (ASM) and 2007 Economic Census,[6] or the National Bureau of Economic Research.[7] In the event of conflicting data, staff referred to the most recent numbers for the ASM. In the previous leakage analysis applied to original entrants to the Cap-and-Trade Program in 2010, staff used data corresponding to 2008 when applying emissions data from taken from the MRR and 2005 data when applying emissions data taken from the IAR.[8] Unless these data are not available, these are the dates from which EI data are analyzed in this document as well.

Upon calculating the EI for a sector from the formula given in equation 1 above, the EI metric is categorized into the following four levels:

- High: > 5000 $mtCO_2e$/$M value added
- Medium: 4999 to 1000 $mtCO_2e$/$M value added
- Low: 999 to 100 $mtCO_2e$/$M value added
- Very Low: < 100 $mtCO_2e$/$M value added

The TE metric uses trade share to measure the level of competition from entities outside the jurisdiction of the Cap-and-Trade Program and the ability of covered entities to pass through compliance costs. Trade share is reported as a percentage and measured as follows:

$$\text{trade share} = (\text{imports} + \text{exports}) / (\text{shipments} + \text{imports}) \qquad (2)$$

U.S. Import and Export data is taken from the International Trade Commission[9] (ITC) and Total Value of Shipments data is taken from taken from the U.S. Census Bureau's Annual Survey of Manufacturers and 2007 Economic Census, or the National Bureau of Economic Research. In the analysis completed for the initial set of industrial covered entities, staff used data corresponding to an average value for each input for over the years 2003 to 2008.[10] Unless these data are not available, these are the dates from which TE data are analyzed in this document as well.

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[5] U.S. EPA (2009) Interagency Report on International Competitiveness and Emission Leakage, Data Annex. Retrieved June 30, 2013 from http://www.epa.gov/climatechange/EPAactivities/economics/legislativeanalyses.html#interagencyReport .

[6] U.S. Census Bureau's American Finder. Retrieved August 23, 2013 from http://factfinder2.census.gov/faces/nav/jsf/pages/index.xhtml

[7] National Bureau of Economic Research, NBER-CES Manufacturing Industry Database (1958-2009) 1997 NAICS version. Retrieved June 20, 2013 from http://www.nber.org/data/nberces5809.html

[8] These calculations can be found in the 2010 Appendix K to the 2010 Cap-and-Trade Regulation previously referenced in footnote 3.

[9] International Trade Commission Interactive Tariff and Trade DataWeb. Retrieved August 23, 2013 from http://dataweb.usitc.gov/

[10] These calculations can be found in the 2010 Appendix K to the 2010 Cap-and-Trade Regulation previously referenced in footnote 3.

Upon calculating the trade share for a sector from the formula given in equation 2 above, the TE metric is categorized into the following three levels:

- High: > 19 %
- Medium: 19 to 10%
- Low: < 10%

Leakage Risk Categories

The leakage risk is category is determined by the combination of the EI and TE metrics from the previous section. This is demonstrated in Table 1.

Table 1 Leakage Risk Categorization

[illegible]	Emissions Intensity	Trade Exposure
[illegible]	High	High Medium Low
	Medium	High
[illegible]	Medium	Medium Low
	Low	High Medium
[illegible]	Low	Low
	Very Low	High Medium Low

For example from this table it is clear that an emission intensity category of high combined with any trade exposure category will result in a leakage risk category of high. Whereas an emissions intensity category of very low combined with any combination of trade exposure category would result in a leakage risk category of low. An emissions intensity category of either low or medium would need to be check against the specific category of trade exposure to determine the corresponding leakage risk category.

Leakage Analysis for Newly Covered Sectors

Staff applied the leakage metrics described earlier to industrial sectors representing the activities of new entrants to the Cap-and-Trade Program. The EI data, EI value and the resulting EI category can be found below in Table 2.

Table 2 Emissions Intensity Summary Data for New Sectors

NAICS Code	Description	Emissions* ($MMTCO_2e$)	Value Added** ($ millions)	Emissions Intensity (EI) ($MTCO_2e$***/$ millions)	EI Category
212299****	All Other Metal Ore Mining	0.5*****	ND******	ND******	Medium
324121	Asphalt Paving Mixture and Block Manufacturing	8.6	3,425	2,511	Medium
325193	Ethyl Alcohol Manufacturing	7.9	3,152	2,506	Medium
332510	Hardware manufacturing	1.1	5,791	190	Low
336414	Guided Missile and Space Vehicle Manufacturing	1.0	6,677	150	Low
332112	Nonferrous Forging	0.9	1,114	808	Low

** Emissions are national data obtained from U.S. EPA's Interagency Report with units in million metric tons CO_2 equivalent ($MMTCO_2e$).*

*** Value added are national data obtained from National Bureau of Economic Research, NBER-CES Manufacturing Industry Database (1958-2009) 1997 NAICS version. and are an average of the values reported from 2004 to 2006.*

**** Units in metric tons of CO_2 equivalent ($MTCO_2e$).*

***** The emissions intensity reported here is specific to the activity of mining rare earth metals which is only a small part of sector 212299.*

****** Emissions are a future projection based upon engineering analysis due to the transitional state of the facility.*

******* Because the activity of mining of rare earth metals is unique to only one facility in the United States, and this data is not available anywhere else, this data is treated as confidential.*

The EI analysis for the sector with NAICS code 212299 is specific to the activity of mining of rare earth metals. There currently exists only one facility in the United States and California that staff is aware of whose primary activity is the mining of Rare Earth Metals. Further, due to dynamically changing industry conditions, staff needed to rely on future emissions projections based upon an engineering analysis of ongoing capital improvements to the facility and future production capacity estimates. Due to the confidential nature of this data, only the emissions estimate and EI categorization are provided in this document. Because of these complexities, future entrants to the Cap-and-Trade program under the NAICS code of 212299 may require a new EI analysis due to the uniqueness of this sector and the activity of mining of rare earth metals.

The trade share data, trade share value and the resulting TE category can be found below in Table 3.

Table 3 Trade Exposure Summary Data for New Sectors*

NAICS Code	Description	Total Value of Shipments** ($ millions)	Value of Exports FASV*** ($ millions)	Value of Imports LDPV**** ($ millions)	Trade Share	Trade Exposure Category
212299	All Other Metal Ore Mining	2,301	1,300	1,345	72.5%	High
324121	Asphalt Paving Mixture and Block Manufacturing	10,232	74	76	1.5%	Low
325193	Ethyl Alcohol Manufacturing	9,230	183	922	10.9%	Medium
332510	Hardware manufacturing	9,966	2,059	5,206	47.9%	High
336414	Guided Missile and Space Vehicle Manufacturing	14,610	11	54	0.4%	Low
33211(2)*****	Nonferrous Forging	29,074	355	357	2.4%	Low

** Data averaged from 2003 to 2008.*

*** Value of shipments are national data obtained from National Bureau of Economic Research, NBER-CES Manufacturing Industry Database (1958-2009) 1997 NAICS version.*

**** Free alongside ship value are national data, obtained from the International Trade Commission (ITC).*

***** Landed duty paid value are national data, obtained from the ITC.*

****** Sector data was aggregated to 5 digits NAICS level due to lack of ITC data at 6 digit NAICS level.*

Staff applied TE analysis of the broader sector of 212299 based upon publicly available data to the activity of rare earth mining because, based upon engineering analysis for the years 2003 to 2008, it appears conservative and applying special analysis for this activity would not alter the TE category at the present time.

Staff needed to use a TE analysis aggregated to the 5 digit NAICS code level for sector 332112 due to a lack of publicly available import and export data on this sector at the ITC.

The EI and TE leakage metrics are combined per the strategy given in Table 1 to generate the leakage risk category for each new sector covered under the Cap-and-Trade program. These leakage categories are given below in Table 4.

Table 4 Leakage Categorization Summary for New Sectors

NAICS Code	Description	Emissions Intensity		Trade Exposure		Leakage Categorization
212299*	All Other Metal Ore Mining	ND**	Medium	72.5%	High	High
324121	Asphalt Paving Mixture and Block Manufacturing	2511	Medium	1.5%	Low	Medium
325193	Ethyl Alcohol Manufacturing	2506	Medium	10.9%	Medium	Medium
332112	Nonferrous Forging	808	Low	2.4%	Low	Low
332510	Hardware manufacturing	190	Low	47.9%	High	Medium
336414	Guided Missile and Space Vehicle Manufacturing	150	Low	0.4%	Low	Low

** The leakage category reported here for sector 212299 is specific to the activity of mining rare earth metals which is only a small part of sector 212299.*

*** Because the activity of mining of rare earth metals is unique to only one facility in the United States, and this data is not available anywhere else, this data is treated as confidential.*

Changes to Leakage Risk Classification of Existing Sectors

Staff analyzed newly available data on the TE metric for those NAICS sectors for which data was available. From this analysis, staff found that since the original 2010 TE analysis for the sector 327993 (Mineral Wool Manufacturing), imports and exports have been rising relative to total value of shipments such that the trade share given in equation 2 earlier in this paper has risen for this sector such that TE has gone from a five year average of 17.5%[11] to the most recent five year average of 21.0%. This can be seen in Table 5.

Table 5 Moving Average Trade Share for Mineral Wool Manufacturing Sector

NAICS Code	2002 - 2007	2003 - 2008	2004 - 2009	2005 - 2010	2006 - 2011
327993	16.3%	17.5%	18.7%	19.8%	21.0%

[11] This was the value reported in Appendix K to the 2010 Cap-and-Trade Regulation previously referenced in footnote 3.

This trend is further illustrated below in Table 6 for this sector when looking at the TE metric applied annually over the most recent decade for which data is available.

Table 6 Annual Trade Share Trend for Mineral Wool Manufacturing Sector

NAICS Code	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
327993	14.0%	14.9%	16.1%	16.9%	17.3%	18.0%	21.6%	23.2%	23.7%	24.0%

The trend in Table 5 clearly indicates a gradual change in trade share that moves this sector to a high TE categorization. The most recent TE, when combined per the strategy in Table 1 with the previously determined EI category of medium, results in a new leakage categorization for this sector of high. This can be seen below in Table 7.

Table 7 New Leakage Risk Category for Mineral Wool Manufacturing Sector

NAICS Code	Description	Emissions Intensity		Trade Exposure		Leakage Categorization
327993	Mineral Wool Manufacturing	1102	Medium	21.0%	High	High

Staff did not find any similar trend for other sectors for which public data was available that resulted in a similar shift of TE categorization.

Appendix C:
New and Modified Product-Based Benchmarks

Greenhouse Gas Benchmarks

Greenhouse gas (GHG) benchmarks are metrics that enable the comparison of GHG performance across similar industrial facilities. As described in staff's Initial Statement of Reasons (ISOR) for the Cap-and-Trade Regulation, GHG emissions intensity benchmarks are a key part of the calculation methodology to determine the annual number of free allowances allocated to each eligible industrial facility in the Cap-and-Trade Program[1]. There are two methods of benchmarking: 1) product-based benchmarking (PBB) and 2) energy-based benchmarking (EBB). A product-based benchmark is a function of the quantity of GHGs released per unit of industrial product output. A generic form of a product benchmark is shown in Equation 1.

Equation 1. Example Product Benchmark Formula

$$GHG\ Benchmark = \frac{Emissions\ (tonnes\ CO_2e)}{Output\ (tons)}$$

In the energy-based approach, the benchmark is a function of how many GHGs are emitted to produce the energy that is used at a facility. A generic form of an energy-based benchmark is shown in Equation 2. An energy-based benchmark is based on: 1) boiler efficiency which is set at 85%, and 2) fuel choice, set at natural gas.

Equation 2. Example Energy-Use Benchmark Formula

$$GHG\ Benchmark = \frac{Emissions\ (tonnes\ CO_2e)}{Energy\ Used\ (MMBtu)}$$

A distinct difference between PBB and EBB is that PBB is updating while EBB is fixed. The amount of free allocation for PBB is updated annually based on the recent production level whereas it remains constant for EBB at a historical baseline level. This is the primary reason why PBB is ARB's preferred approach in order to incentivize continued/increased production in California. Resolution 11-32 directs Staff to continue working to include more sectors in the PBB methodology. As part of the efforts, ARB contracted with Ecofys and UC Berkeley/Northwestern University to acquire adequate engineering knowledge to develop benchmarks for the sectors that have complex processes such as refineries and food/beverage processing.

[1] See ISOR, Appendix J: http://www.arb.ca.gov/regact/2010/capandtrade10/capv4appj.pdf

General Benchmarking Process

Staff reached out to both the sectors currently subject to the EBB and the sectors identified to be newly entering the program to assess the feasibility of developing PBBs. The assessment included 3 steps: 1) acquire a sound technical understanding of manufacturing process, 2) evaluate the potential number of product units to benchmark, and 3) consult with the covered facilities/stakeholders to determine if sufficient data would be available to construct robust benchmarks.

Throughout the process, Staff applied the below principles to ensure that new benchmarks would be developed in a manner consistent with the existing benchmarks.

1. One product, one benchmark
    - Product unit definition is not differentiated by technology, fuel mix, size, age, climatic circumstances or raw material quality.
    - When a set of products undergoes a similar set of processing steps but may be refined to different levels, use Equivalence Factors (EF) to normalize the target content of the product[2].
2. Use data years that are representative of normal operation years
    - The benchmark should be set using data years with normal operational conditions so that the value is not affected by factors irrelevant to the operational efficiency. Therefore years with any abnormal events should be excluded from the calculation. Examples of abnormal events are maintenance, temporal shutdown, or change in the operation due to the external factors uncontrollable by the operator.
    - Unless any abnormal events are identified, data years 2008-10 should be used because 1) ARB has Mandatory Reporting Regulation data to ensure the rigorousness of the data quality (2009 and 10 data are verified), and 2) it levels the playing field with the sectors with existing benchmarks for which 2008-10 data were used primarily. Since efficiency tends to improve over time, using the same years across the board ensures that the efficiency improvements are taken into account in the fair and equal manner.

Staff proposes to establish new product-based benchmarks for the following sectors:

- Diatomaceous earth mining and processing
- Aluminum and aluminum alloy billet manufacturing
- Iron foundry
- Forging and stamping
- Lead acid battery recycling
- Onshore natural gas processing plants

[2] Example of this includes tomato paste: whereas the targeted content is tomato solids, different products can contain different level of moisture. See Page 7 of this Appendix for detailed description of EF.

- Food and beverage processors (tomato processing, poultry processing, dehydrated flavor processing, sugar beet refining, juice manufacturing, snack chips manufacturing, dairies and pistachios/almond processing)

Sector-by-Sector Benchmark Product Proposal

This section provides the description of the product, manufacturing process, number of covered entities under the Cap-and-Trade Program and proposed product unit on a sector-by-sector basis.

Diatomaceous earth (NAICS 212399)

Diatomite is a chalk-like, soft, friable, earthy, very fine-grained, siliceous sedimentary rock comprised of fossilized diatom remains. Diatomite deposits form from an accumulation of amorphous hydrous silica cell walls of dead diatoms in both oceanic and fresh waters. These microscopic single-cell aquatic plants (algae) contain an internal, elaborate siliceous skeleton consisting of two frustules (valves) that vary in size from less than 1 micrometer (µm) to more than 1 millimeter in diameter but are typically 10 to 200 µm in diameter. The frustules have a broad variety of delicate, lacy, perforated shapes, including cylinders, discs, feathers, ladders, needles, and spheres (U.S. GS 2011). Due to the difference in the habitat, freshwater diatoms have different characteristics than marine diatoms. After mining, diatom ore is dried, milled and then calcined to make different products.

There are 2 diatomite miner/processors subject to the Cap-and-Trade Program and there is one processor of freshwater diatomaceous earth. Staff collected data for freshwater diatom filter aids and proposes to define the product unit as following:

- Short ton of freshwater diatomite filter aids

Aluminum and aluminum alloy billet manufacturing (NAICS 331314 Secondary Smelting and Alloying of Aluminum)

Metal billets are a length of metal that has a round or square cross-section that is manufactured via casting. To create aluminum and aluminum alloy billets, scrap aluminum consisting of aluminum, aluminum alloys, and alloying ingredients is melted, and cast into billets. Following melting and casting operations, billets may undergo additional processing such as heat treatment.

There is one aluminum and aluminum alloy billet manufacturer subject to the Cap-and-Trade program. Staff proposes to define product unit as following:

- Short ton of aluminum and aluminum alloy billet

Iron Foundry (NAICS 331511)

Foundries manufacture castings by pouring metal melted in a furnace into a mold of a desired, and potentially intricate, shape. Achieving the same detail of form as a casting would require extensive tooling and shaping of metal from a mill (US EPA 2002).

There is one iron foundry subject to the Cap-and-Trade program that manufactures ductile iron pipes.

At a pipe manufacturing facility, iron is melted in the cupola furnace at approximately 1,550 °C using scrap steel and recycled materials. In order to obtain ductile cast iron, the iron is injected in the converter with a magnesium alloy. Pipes are then manufactured from the injected iron using a centrifugal casting process. The pipes leave the centrifugal casting shop and are annealed at 960 °C. All pipes are then given a zinc or zinc-aluminum casing (Duktus 2013).

Staff proposes to define product unit as following:

- Short ton of ductile iron pipes

Forging and stamping (NAICS 33211)

Forging is the process of heating metals to a forging temperature well below the melting temperature and then forming the parts through a series of mechanical operations. Different finish product types would require different numbers of processes.

There are 2 forging companies in California that are above or close to 25,000 MT CO2e annual emission threshold to determine the applicability for the Cap-and-Trade Program. There is also a potential of new entrants at a later time. There is no known stamping operator in California subject to the Cap-and-Trade Program.

In general, forging can be grouped in 4 categories: impression die, cold die, open die and seamless rolled ring. Staff obtained data for seamless rolled ring, but not for other types of products due to the fact that the shape, size and metal property of the end products heavily depend on the customer specifications.

Based on the product data ARB obtained, Staff proposes to define product unit as following:

- Short ton of seamless rolled ring

Lead acid battery recycling (NAICS 331492, Subpart R: Lead Production)

Lead is a metal used to produce various products such as batteries, ammunition, construction materials, electrical components and accessories, and vehicle parts. Approximately, 89 percent of lead is used to produce batteries.

A secondary lead smelter produces lead and lead alloys from lead-bearing scrap metal. The incoming lead scrap materials are first pre-treated to partially remove metal and nonmetal contaminants. The resulting lead scrap is smelted using either a blast furnace or reverberatory

furnace. The molten lead from the smelting furnace is refined in kettle furnaces, and then cast into ingots or used to produce lead alloy products (US EPA 2009).

There are 2 lead acid battery recyclers that are projected to be newly subject to the Cap-and-Trade Program.

Staff proposes to define the product unit as following:

- Short ton of lead and lead alloy

Onshore natural gas processing plants (NAICS 211112)

Staff proposes to define product units as follows:. Barrel of Gas Processed Equivalent

Please see the discussion in "Modifications to existing benchmarks" section below for detailed information.

Food and beverage sector (NAICS 311, 312120 and 312130)

The Cap-and-Trade Program covers the following food processing sectors: tomato processing, poultry processing, dehydrated flavor processing, sugar beet refining, juice manufacturing, snack chip manufacturing, dairy processing, pistachio and almond processing. It also covers beer, wine and spirits from the beverage sector.

Engagement of external expertise

Food and beverage processing are complex systems to benchmark because one type of input can go through series of process steps to end up in a variety of products. Facilities commonly produce several different products by utilizing complex processing that incorporates the exchange of mass and heat among processing lines. It requires sound engineering understanding of the manufacturing process in order to develop robust benchmarks.

ARB contracted with Ecofys and UC Berkeley/Northwestern University to provide additional expertise. The ongoing project (The Project) under this contract has been conducting full analyses working with stakeholders and covered facilities to develop technically sound benchmarks for the food and beverage sectors. The process descriptions and resulting product definitions described below rely on work done by The Project team. A report may be released at a later date describing all the technical details that supported the Staff proposals for product definitions for the food and beverage sector.

General approach

As described earlier, Staff followed three main steps to develop product-based benchmarks for all sectors, including the food and beverage sectors. Each step included a substantial amount of

work to overcome the challenges associated with the complex manufacturing processes unique to the food/beverage sector including:

- Facilities often manufacture many different food/beverage products using a number of energy intensive processes.
- Fuel is often combusted in a central boiler and process heat is moved around the facility as steam for use in plant manufacturing processes.
- Many facilities lack the sub-metering necessary to easily quantify how much energy from the central boiler should be assigned to different products.
- It is common for various final products to have shared upstream thermal processing.

1) Acquire sound technical understanding of manufacturing process

As an initial step, the Project conducted an extensive literature review, including academic research, legislation, and industry publications. The research team also visited eight covered food processing facilities to ensure that the research was based on the actual processing configurations of the plants subject to the Cap-and-Trade Program. On- and off-site interviews were conducted with plant managers and operators to learn about the processes, equipment, and energy involved in making specific food products.

Staff found that PBB development becomes more difficult with increasing process heterogeneity and decreasing process monitoring, especially considering the sub-metering of energy use at each process level. Staff also found that the level of process heterogeneity varied for different food processors, and the quality of process monitoring varied at an individual facility level.

2) Evaluate potential number of product units to benchmark

Based on the information collected through step 1, the research team characterized six typical process configuration types commonly used in the food and beverage sector. This characterization became the basis to determine the methodology to allocate facility-wide energy consumption to each product and to determine which products should be given separate benchmarks and which products should be grouped. The description of each process configuration is shown below.

a) Linear Process Lines

A linear process is a single process line with a single product output. This is the most straightforward processing configuration. Although the inputs to the process may go through multiple process steps, the energy intensity of an output can be derived by dividing total energy input by the amount of output since there is only one product output.

b) Mixing Process Lines

A mixing process line is very similar to a linear process line. However, a mixing process line has multiple raw material inputs which are processed separately before being mixed to produce a single final product. Since only one product is manufactured, the energy intensity can be

calculated by dividing total energy by the amount of output. It is critical to include the energy from all the mixing lines as part of the total energy.

c) Parallel Process Lines

Parallel process lines are independent linear processing lines that run parallel. The product output of parallel process lines may be the same or different. Determining the energy intensity for a parallel configuration is straightforward if the thermal use for each line is quantified separately. When no energy sub-metering for each linear process is available, a sound engineering estimate of the distribution of energy between the lines has to be applied.

d) Branching Process Lines

A branching process line yields several final products from a single raw material stream. Products manufactured in a branching process may undergo thermal processing before and after process stream splits. Common processes may be shared by multiple products at any point of the processing. The difficulty arises when a common process does not have the capability to split the energy consumed by each end product. For example, pasteurization can be used by both cream and butter or evaporation by powdered and condensed milk. It becomes essential to combine energy meter readings available at a plant or unit level with estimated theoretical energy requirements for different products to calculate total energy consumption by each product.

e) Formulated Process Lines

Formulated process lines yield multiple products from multiple processed or raw materials. The key step that distinguishes a formulated process line is the combination of these materials into different products at different ratios, each of which may undergo additional processing. This type of facility is challenging because the different formulations of the product may contain ingredients with very different energy intensities. There can also be hundreds of different products with different percentages of different ingredients. Instead of trying to create individual benchmarks for each formulation, benchmarks can be set for each ingredient. For example, instead of a benchmark for a recipe of 20% diced tomatoes and 80% tomato paste, benchmarks can be set for diced tomatoes and tomato paste. This allows Staff to develop benchmarks for a small number of inputs that can be applied to a wide range of reformulated products.

f) Hybrid Process Lines

Hybrid processing includes a combination of the previously discussed configurations. Product definitions can be developed using the approaches for the individual types of lines.

Additional Consideration

For some products in the food processing sector, the same processing line may be refined to different concentrations. Other products may undergo a concentration or shearing process that results in the loss of mass. These situations presented complications in determining product

definitions because concentration or shearing processes lead to a loss of product mass and higher levels of thermal concentration require increased thermal input. Staff proposes to apply Equivalency Factors (EFs) to normalize the difference in emission intensity among similar products undergoing concentration or mass loss steps. An example is tomato paste. Instead of differentiating aseptic tomato paste that has different solid content, Staff proposes to normalize it at 31% tomato soluble solids for all aseptic tomato paste. This allows equitable energy efficiency comparison among different paste with different solid content while maintaining one-product, one-benchmark principle. This approach allows for the different concentrations of products to be expressed in terms of an equivalent output in one product definition. This is a reasonable approach to avoid the situation where benchmarks need to be developed for each individual concentration of a given product.

3) Consult with the covered facilities/stakeholders for data collection to construct product-based benchmarks

Once product were defined, Staff worked with covered facilities and/or trading associations that represent covered sectors to start collecting production and energy consumption data from facilities. Staff proposes the following product definitions:

Table 1: Proposed Product Definition for Food Sector (NAICS 311)

Dairy	Dehydrated Flavors	Poultry
Milk, buttermilk and skim milk	Dehydrated onions	Whole Chicken & Chicken Parts
Cream	Dehydrated garlics	Poultry Deli Products
Butter	Dehydrated peppers	Poultry Protein Meal
Sweetened condensed milk and evaporated milk	Dehydrated parsleys	
Powdered Milk	Dehydrated spinach	
Concentrated milk		
Cheese		
Lactose		
Dry Whey Protein Concentrate		
Deproteinized whey		
Snacks & Chips	**Sugar**	**Tomatoes**
Fried Potato Chips	Granulated-refined sugar	Aseptic tomato paste
Baked Potato Chips		Aseptic whole/diced tomato
Corn Chips		Non-aseptic tomato paste
Corn Curls		Non-aseptic whole/diced tomato
Pretzels		Non-aseptic tomato juice
		Canned non-tomato additive
Pistachios/Almonds		
Pistachios		
Almonds		

Table 2: Proposed Product Definition for Beverage Sector (NAICS *312120 and 312130)*

Breweries	Wine, Spirits & Concentrates
Lager beer	Distillate products
	Grape juice concentrate
	Liquid color concentrate
	Crystal color concentrate
	Activin

Modification to the Existing Benchmarks

Staff reviewed the existing benchmarks to ensure that they were used the best approach and most appropriate data. . Several sectors submitted comments to ARB requesting benchmark review: oil and gas extraction, tissue, boxboard, flat glass, container glass and cold steel rolling.

As part of the review process, staff worked with stakeholders to 1) recalculate the existing benchmarks to ensure all the supporting data were correct and calculated appropriately, 2) collect more extensive/detailed data to perform further analysis if necessary, and to 3) identify any abnormal events that skewed the benchmark making it non-representative of normal operation years. Below is sector-by-sector description of the issues and proposed changes.

Oil and gas extraction

For the upstream oil and gas extraction sector (NAICS codes 211111 and 211112), staff proposed revisions to the existing product-benchmarks for thermal EOR crude extraction, non-thermal crude extraction, and natural gas liquid extraction. In addition, staff also proposed a new benchmark for onshore natural gas processing plants that process greater than 25 million standard cubic feet of natural gas per day (MMscf/day).

Staff proposes to define product unit for large gas processing plants as the following:

- Barrel of Gas Processed Equivalent

Staff initiated a voluntary data collection survey in order to reassess the benchmarks for the upstream oil and gas extraction sector. This survey was distributed in late 2012 to all covered facilities emitting over 25,000 tons CO2e that extract and process oil and gas, including dry gas, and/or natural gas liquids. All covered facilities in California successfully responded to the survey request; thus all covered entities are represented in the proposed benchmarks for this sector.

The existing benchmark for non-thermal crude extraction included production and emissions from both small (<25 MMscf/day) and large (>25 MMscf/day) gas processing plants. Under the proposed benchmarks, the emissions and production for small gas plants are still included in the non-thermal benchmark as they are considered the same facility as the onshore production

facility by definition under MRR. The emissions from the large gas plants are now included in the new benchmark for onshore natural gas processing plants, as they are considered separate facilities under MRR. The rationale to keep the large gas plants as separate facilities derives from stakeholders' requests to maintain consistency between MRR and USEPA's GHG Mandatory Reporting Program. The total allocation for the sector remains the same whether there is a gas processing benchmark or whether the emissions from the large gas plants are included in the non-thermal benchmark.

Under the proposed benchmarks, small gas processing plants would receive an allocation using the proposed non-thermal production benchmark. Large gas processing plants would receive an allocation for their gas processed using the proposed natural gas processing benchmark; allocation for oil and gas production would be based on the proposed non-thermal production benchmark. As a result of the new data received as part of the voluntary data collection survey, all three existing benchmarks for thermal, non-thermal, and natural gas production went down slightly.

Tissue manufacturing

There are two tissue manufacturers subject to the tissue benchmark. One company commented that it produced premium quality tissue products that did not compare directly to the products that the other facility produced. 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. The difference in quality comes from the structure of the paper that determines the ratio of the fiber and the void. More water can be absorbed if there are more voids that are structured to better hold water. Staff believes that this difference can be normalized by comparing the mass of tissue product that holds the same amount of water. Applying the concept of Equivalent Factor (EF), staff proposes to change the product unit from the short ton of tissue to the short ton of tissue that holds the same units of water by using the following calculation:

> Tissue produced adjusted by water absorption capacity = tissue produced (air dried short ton) x weighted grams of water absorbed by weighted gram of tissue product

Weighted water absorbency capacity was quantified by sampling total 6 products that 2 companies produce using ISO 12625-8:2010 as a test method. Two laboratories conducted the test: one third-party lab and ARB's Monitoring & Laboratory Division.

Staff was also able to collect complete base year data from the two participating companies.

Staff proposes to modify tissue product unit from short air dried to of tissue to short air dried ton of tissue produced adjusted by water absorbency capacity.

Recycled Boxboard

Staff reviewed the recycled boxboard benchmark and identified that longer data periods made the benchmark more representative. Staff also identified that an abnormal event in the year

2010. Staff proposes to modify recycled boxboard benchmark using additional data years and excluding 2010.

Flat glass

The flat glass benchmark was developed using data from an ARB-conducted industry survey in 2009 and maintained extensive data/information for process equipment, production and emissions.

One company commented that the existing benchmark was not reflective of the actual details of their operation and requested a review. Staff examined all the data that supported the current benchmark and found that there were some assumptions that needed to be validated and also identified some erroneous calculations. In order to set the benchmark values based on the most accurate data available, staff solicited complete datasets from the three flat glass companies. After reviewing the data, staff concluded that two years should be excluded due to abnormal events at some facilities. Staff proposes to revise flat glass benchmark excluding those two years and correcting the calculations.

Container glass

The container glass sector has commented that the current benchmark that uses the data year 2009 was not appropriate because it did not recognize early actions taken by the facilities. ARB's benchmark stringency principle is that the early actions are already recognized in the benchmark in the way that they always contribute to outperform their peers and reduce compliance obligation. Nonetheless, staff reviewed the data by working with the stakeholders who provided ARB with complete data sets for the year 2005-10. This time staff was able to obtain cullet consumption data that was not available when the existing benchmark was established. Cullet (recycled glass) plays a major role in reducing GHG emission from the glass sector because it can replace virgin feedstock such as soda ash and/or limestone which liberates CO2e through calcining process.

Staff identified that the consumption of cullet at five container glass facilities fluctuated substantially at an individual facility basis whereas the aggregated trend showed continued increase of cullet use per unit of glass produced. According to CalRecycle's Biannual Report of Beverage Container Sales, Returns, Redemption & Recycling Rates[3], the amount of glass recycled at a state-wide level continued to increase until 2008 and started declining marginally after 2009. Various factors such as economic health of collecting activities or the quality of collection can contribute to this trend which is not a linear increase. Staff agrees that the supply of cullet may not be controllable by purchasing facilities and believes that using more years would address the temporal fluctuation of the cullet use. Staff proposes to use a wider range of data years for container glass to account for this wide variability.

[3] The report is available at: http://www.calrecycle.ca.gov/bevcontainer/Rates/BiannualRpt/default.htm

Steel cold rolling

Steel cold rolling has multiple processes with different energy requirements. USS-POSCO Industries (UPI) provided new and more accurate data to allocate facility-wide emissions to each process and associated output. After reviewing, staff made some adjustments to the emissions assigned to each production process based on UPI's new data. Staff also excluded one year from UPI's dataset since there was equipment maintenance that affected the reading of natural gas metering. Staff proposes to modify the benchmark for pickled steel, cold rolled and annealed steel, galvanized steel and tin coated product. Since there are 2 facilities under steel cold rolling, staff applied either weighted average x 90% or best in class to make sure at least one facility would achieve the benchmark.

Gypsum

Staff proposes to change benchmark unit definitions for gypsum tobe consistent with the Mandatory Reporting Requirements. The overall approach and the benchmark values for gypsum sector are not changed.

Cement

Using biogas is a viable option for covered entities to reduce GHG emissions. Staff is proposing to modify the benchmark for cement sector to take into account biomass consumed on-site. This is consistent with other sectors that combust biogas.

Appendix E:

PROPOSED REGULATION ORDER

Amend Subchapter 10 Climate Change, Article 5, sections 95802, 95811, 95812, 95813, 95814, 95821, 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, and 96022, title 17, California Code of Regulations. Proposed adoption of new sections 95894, 95895, 95923, 95979.1, new Appendix B, and new Appendix C, title 17, California Code of Regulations, to read as follows:

Article 5: California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments Issued by Linked Jurisdictions

Note: The pre-existing regulation text is set forth below in normal type. The proposed amendments are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions. "***" indicates that sections of regulation not printed are not changed.

§ 95802. Definitions.

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(1) "Account Viewing Agent" means an individual authorized by a registered entity to view all the information on the entity's accounts contained in the tracking system.

(2) "Accounts Administrator" means the entity acting in the capacity to administer the accounts identified in this regulation. This may be ARB, or could be an entity ARB enters into a contract with.

(3) "Activin" means the extract from grape seeds containing concentrations of proanthocyanidin.

(4) "Activity-Shifting Leakage" means increased GHG emissions or decreased GHG removals that result from the displacement of activities or resources from inside the offset project's boundary to locations outside the offset project's boundary as a result of the offset project activity.

~~(4)~~(5)"Additional" means, in the context of offset credits, greenhouse gas emission reductions or removals that exceed any greenhouse gas reduction or removals otherwise required by law, regulation or legally binding mandate, and that exceed any greenhouse gas reductions or removals that would otherwise occur in a conservative business-as-usual scenario.

~~(5)~~(6) "Adjusted Clinker and Mineral Additives Produced" means annual amount of clinker and mineral additives (limestone and gypsum) derived by using the following metric: Adjusted clinker and mineral additives produced = clinker produced x (1 + (limestone and gypsum consumed)/clinker consumed)).

~~(6)~~(7) "Adverse Offset Verification Statement" means an Offset Verification Statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted Offset Project Data Report is free of an offset material misstatement, or that it cannot attest that the Offset Project Data Report conforms to the requirements of this article or applicable Compliance Offset Protocol.

~~(7)~~(8) "Air Dried Ton of Paper" means paper with 6 percent moisture content.

(9) "Air Pollution Control District" or "Air Quality Management District" or "Air District" means any district created or continued in existence pursuant to the provisions of Part 3 (commencing with Section 40000) of Division 26 of the Health and Safety Code.

~~(8)~~ (10) "Allowance" means a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(11) "Almond" means the edible seeds of the almond (*Prunus amygdalus*).

~~(9)~~(12) "Alternate Account Representative" means an individual designated pursuant to section 95832 to take actions on an entity's accounts.

(13) "Aluminum and aluminum alloy billets" is a solid bar of nonferrous metal, produced by casting molten aluminum alloys, and suitable for subsequent rolling, casting, or extrusion. Aluminum alloy is an alloy in which aluminum is the predominant metal and the alloying elements may typically be copper, magnesium, manganese, zinc, or other elemental additives or any combination of elements added.

~~(10)~~(14) "Annual Allowance Budget" means the number of California Greenhouse Gas Allowances associated with one year of the Cap-and-Trade Program in subarticle 6.

~~(11) "API Gravity" means a scale used to reflect the specific gravity (SG) of a fluid such as crude oil, water, or natural gas. The API gravity is calculated as [(141.5/SG) - 131.5], where SG is the specific gravity of the fluid at 60°F, where API refers to the American Petroleum Institute.~~

~~(12)~~(15)"ARB Offset Credit" means a tradable compliance instrument issued by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable.

(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 conditions.

(17) "Aseptic whole / diced tomato" means whole / diced tomato packaged using a system in which the product is sterilized before filling into pre-sterilized packs under aseptic conditions.

~~(13)~~(18)"Asphalt" means a dark brown-to-black, cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

~~(14)~~(19)"Asset Controlling Supplier" means any entity that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for these facilities even though it does not own them, and is assigned a supplier-specific identification number and system emission factor by ARB for the wholesale electricity procured from its system and imported into California. Asset Controlling Suppliers are considered specified sources.

~~(15)~~(20) "Assigned Emissions" or "Assigned Emissions Level" means an amount of emissions, in CO_2e, assigned to the reporting entity by the Executive Officer under the requirements of section 95103(g) of MRR.

~~(16)~~(21)"Associated Gas" or "Produced Gas" means a natural gas that is produced in association with the production of crude oil.

~~(17)~~(22)"Auction" means the process of selling California Greenhouse Gas Allowances, along with allowances from External Greenhouse Gas Emissions Trading Systems with which California has linked its Cap-and-Trade Program pursuant to subarticle 12, by offering them up for bid, taking bids, and then distributing the allowances to winning bidders.

~~(18)~~(23)"Auction Purchase Limit" means the limit on the number of allowances one entity or a group of affiliated entities may purchase from the share of allowances sold at a quarterly auction.

~~(19)~~(24)"Auction Reserve Price" means a price for allowances below which bids at auction would not be accepted.

~~(20)~~(25)"Auction Settlement Price" means the price announced by the Auction Administrator at the conclusion of each quarterly auction. It is the price which all successful bidders will pay for their allowances and also the price to be paid to those entities which consigned allowances to the auction.

~~(21)~~(26)"Authorized Project Designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

~~(22)~~(27)"Aviation Gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications are as stated in MRR, section 95102(a).

(28) "Baked potato chips" means a potato chip made from a potato dough that is rolled to a specified thickness, cut into a chip shape and then toasted in an oven.

~~(23)~~(29)"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

~~(24)~~(30)"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

~~(25)~~(31)"Banking" means the holding of compliance instruments from one compliance period for the purpose of sale or surrender in a future compliance period.

~~(26)~~(32)"Barrel of Oil Equivalent," with respect to reporting of oil and gas production, means barrels of crude oil produced, plus associated gas produced and dry gas converted to barrels at 5.8 MMbtu per barrel.

~~(27)~~(33)"Biodiesel" means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) A mono-alkyl ester;

(C) Meets American Society for Testing and Material designation ASTM D 6751-08 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, 2008*);

(D) Intended for use in engines that are designated to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

~~(28)~~(34)"Biogas" means gas that is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including anaerobic digestion, anaerobic decomposition, and thermochemical decomposition. These processes are applied to biodegradable biomass materials, such as manure, sewage, municipal solid waste, green waste, and waste from energy crops, to produce landfill gas, digester gas, and other forms of biogas.

~~(29)~~(35)"Biomass" means non-fossilized and biodegradable organic material originating from plants, animals, and microorganisms, including products, by-products, residues, and waste from agriculture, forestry, and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

~~(30)~~(36)"Biomass-Derived Fuels" or "Biomass Fuels" or "Biofuels" means fuels derived from biomass.

~~(31)~~(37)"Biomethane" means biogas that meets pipeline quality natural gas standards.

~~(32)~~(38)"Blendstocks" are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

(39) "Boiler" means a closed vessel or arrangement of vessels and tubes, together with a furnace or other heat source, in which water is heated to produce hot water or steam.

~~(33)~~(40)"Budget Year" means the annual allowance budget assigned pursuant to subarticle 6.

~~(34)~~(41)"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.

(42) "Butter" means the product made by gathering the fat or fresh or ripened milk or cream into a mass, which also contains a small portion of other milk constituents.

(43) "Buttermilk" means the low-fat portion of milk or cream remaining after it has been churned to make butter.

~~(35)~~(44)"Calcium Ammonium Nitrate Solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.

~~(36)~~(45)"Calendar Year" means the time period from January 1 through December 31.

~~(37)~~(46)"California Balancing Authority" shall have the same meaning ascribed in section 95102(a) of MRR.

~~(38)~~(47)"California Electricity Transmission and Distribution System" means the combination of the entire infrastructure within California that delivers electric power from electric generating facilities to end users over single or multiple paths.

~~(39)~~(48)"California Greenhouse Gas Emissions Allowance" or "CA GHG Allowance" means an allowance issued by ARB and equal to up to one metric ton of CO_2 equivalent.

(49) "Canned non-tomato additive" means canned food product produced at a tomato processing facility that is not one of the products above.

~~(40)~~(50)"Cap" means the total number of California GHG Allowances that the Executive Officer issues over a given period of time.

~~(41)~~(51)"Cap-and-Trade Program" means the requirements of this article.

~~(42)~~(52)"Carbon Dioxide" or "CO_2" means the most common of the primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

~~(43)~~(53)"Carbon Dioxide Equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas. Global warming potential values shall be determined consistent with the definition of Carbon Dioxide Equivalent in MRR section 95102(a).

~~(44)~~(54)"Carbon Stock" means the quantity of carbon contained in an identified GHG reservoir.

~~(45)~~(55)"Carbon Dioxide Supplier" or "CO_2 Supplier" means (a) facilities with production process units located in the State of California that capture a CO_2

stream for purposes of supplying CO_2 for commercial applications or that capture the CO_2 stream in order to utilize it for geologic sequestration where capture refers to the initial separation and removal of CO_2 from a manufacturing process or any other process, (b) facilities with CO_2 production wells located in the State of California that extract or produce a CO_2 stream for purposes of supplying CO_2 for commercial applications or that extract a CO_2 stream in order to utilize it for geologic sequestration, (c) exporters (out of the State of California) of bulk CO_2 that export CO_2 for the purpose of geologic sequestration, (d) exporters (out of the State of California) of bulk CO_2 that export for purposes other than geologic sequestration, and (e) importers (into the State of California) of bulk CO_2. This source category is focused on upstream supply and is not intended to place duplicative compliance obligations on CO_2 already covered upstream. The source category does not include transportation or distribution of CO_2; purification, compression, or processing of CO_2; or on-site use of CO_2 captured on-site.

~~(46)~~(56) "Carbon Dioxide Weighted Tonne" or "CO_2 Weighted Tonne" or "CWT" means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes stated in units of metric tons. The CWT 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 CWT 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 CWT factor is expressed as a value weighted relative to crude distillation.

(57) "Carbonation" means the process of dissolving carbon dioxide in water.

~~(47)~~(58) "Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives.

Finished cement is a powder used with water, sand, and gravel to make concrete and mortar.

(59) "Cheese" means a food product derived from milk that is produced in a wide range of flavors, textures, and forms by coagulation of the milk protein casein.

~~(48)~~(60)"Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve onsite generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (a) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (b) Steam turbines generating electricity as a byproduct of steam generation through a fired boiler; (c) Cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this article, a combined-cycle power generation unit, where none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy utilization that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

~~(50)~~(61)"Cold Rolled and Annealed Steel Sheet" means steel that is cold rolled and then annealed. Cold rolling means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature. Annealing is a heat or thermal treatment process by which a previously cold-rolled steel coil is made more suitable for forming and bending. The steel sheet is heated to a designated temperature for a sufficient amount of time and then cooled.

~~(49)~~(62)"Cold Rolling of Steel" means the changes in the structure and shape of steel through rolling, hammering or stretching the steel at a low temperature.

~~(51)~~(63)"Combustion Emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(64) "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 crude distillation.

~~(52)~~(65)"Compliance Account" means an account created by the accounts administrator for a covered entity or opt-in covered entity with a compliance obligation, to which the entity transfers compliance instruments to meet its annual and triennial compliance obligations.

~~(53)~~(66)Compliance Instrument" means an allowance or offset, issued by ARB or by an External Greenhouse Gas Emissions Trading System to which California has linked its Cap-and-Trade Program pursuant to subarticle 12, or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to up to one metric ton of CO_2e.

~~(54)~~(67)"Compliance Obligation" means the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to ARB.

~~(55)~~(68)"Compliance Offset Protocol" means an offset protocol adopted by the Board.

~~(56)~~(69)"Compliance Period" means the three-year period for which the compliance obligation is calculated for covered entities except for the first compliance period. The compliance obligation for the first compliance period only considers emissions from data years of 2013 and 2014.

(70) "Compressed natural gas" or "CNG" means natural gas in high-pressure containers that is highly compressed (though not to the point of liquefaction), typically to pressures ranging from 2900 to 3600 psi.

(71) "Concentrated milk" means the liquid food obtained by partial removal of water from milk. The milkfat and total milk solids contents of the food are not less than 7.5 and 25.5 percent, respectively. It is pasteurized, but is not processed by heat so as to prevent spoilage. It may be homogenized.

~~(57)~~(72)"Conflict of Interest" means, for purposes of this article, a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial Offset Verification Statement of a potential client's Offset Project Data Report, or the person or body's objectivity in performing offset verification services is or might be otherwise compromised.

~~(58)~~(73)"Conservative" means, in the context of offsets, 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.

~~(59)~~(74)"Consumer Price Index for All Urban Consumers" means a measure that examines the changes in the price of a basket of goods and services purchased by urban consumers, and is published by the U.S. Bureau of Labor Statistics.

~~(60)~~(75)"Container Glass Pulled" means the quantity of glass removed from the melting furnace in the container glass manufacturing process where "container glass" is defined as glass products used for packaging.

(76) "Corn chip" is made from masa (ground corn dough) that is rolled to a specific thickness, cut into a chip shape, lightly toasted in an oven, and then deep fried.

(77) "Corn curl" is made from a deep-fried extrusion of masa (ground corn dough).

~~(61)~~(78)"Counterparty" means the opposite party in a bilateral agreement, contract, or transaction.

~~(62)~~(79)"Covered Entity" means an entity within California that has one or more of the processes or operations and has a compliance obligation as specified in subarticle 7 of this regulation; and that has emitted, produced, imported, manufactured, or delivered in 2009 or any subsequent year more than the applicable threshold level specified in section 95812(a) of this rule.

(80) "Cream" means that portion of milk, rich in milk fat, which rises to the surface of milk that is left standing or which is separated from milk by centrifugal force.

~~(63)~~(81)"Crediting Baseline" refers to the reduction of absolute GHG emissions below the business-as-usual scenario or reference level across a jurisdiction's entire sector in a sector-based crediting program after the imposition of greenhouse gas emission reduction requirements or incentives.

~~(64)~~(82)"Crediting Period" means the pre-determined period for which an offset project will remain eligible to be issued ARB offset credits or registry offset credits for verified GHG emission reductions or GHG removal enhancements.

(83) "Crystal color concentrate" means precipitated solids extract from fruits and vegetables whose uses are for altering the color of materials and/or food.

~~(65)~~(84)"Data Year" means the calendar year in which emissions occurred.

~~(66)~~(85)"Deforestation" means direct human-induced conversion of forested land to non-forested land.

(86) "Dehydrated chili peppers" means chili peppers that have been dehydrated to no more than 12 percent water by volume in order to extend the shelf like and to concentrate the flavor. Chili pepper are the fruit of plants from the genus *Capsicum*, members of the nightshade family, Solanaceae.

(87) "Dehydrated garlic" means garlic that has been dehydrated to no more than 6.8 percent water by volume in order to extend the shelf like and to concentrate the flavor. Garlic is an onion-like plant *(Allium sativum)* of southern Europe having a bulb that breaks up into separable cloves with a strong distinctive odor and flavor.

(88) "Dehydrated onions" means onions that have been dehydrated to no more than 5.5 percent water by volume in order to extend the shelf life and to concentrate the flavor. Onion (*Allium cepa*) is a plant that has a fan of hollow,

bluish-green leaves and the bulb at the base of the plant begins to swell when a certain day-length is reached.

(89) "Dehydrated parsley" means parsley that has been dehydrated to no more than 5 percent water by volume in order to extend the shelf like and to concentrate the flavor. Parsley (Petroselinum crispum) is a species of *Petroselinum* in the family Apiaceae.

(90) "Dehydrated spinach" means spinach that has been dehydrated to no more than 7 percent water by volume in order to extend the shelf like and to concentrate the flavor. Spinach (*Spinacia oleracea*) is an edible flowering plant in the family of Amaranthaceae.

~~(67)~~(91)"Delivered Electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

(92) "Deproteinized whey" means products manufactured through the cold ultrafiltration of sweet dairy whey, removing a portion of the protein from sweet whey to result in a non-hygroscopic, free-flowing and clean flavored powder containing greater than 80% carbohydrate (lactose) levels.

(93) "Diced Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. The tomatoes are peeled and diced, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

~~(68)~~(94)"Diesel Fuel" means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and non-taxed fuels.

~~(69)~~(95)"Direct Delivery of Electricity" or "directly delivered" has the same meaning as ascribed to MRR section 95102(a).

~~(70)~~(96)"Direct GHG Emission Reduction" means a GHG emission reduction from applicable GHG emission sources, GHG sinks, or GHG reservoirs that are under control of the Offset Project Operator or Authorized Project Designee.

~~(71)~~(97)"Direct GHG Removal Enhancement" means a GHG removal enhancement from applicable GHG emission sources, GHG sinks, or GHG reservoirs under control of the Offset Project Operator or Authorized Project Designee.

~~(72)~~(98)"Distillate Fuel No. 1" has a maximum distillation temperature of 550 F at the 90 percent recovery point and a minimum flash point of 100 F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

~~(73)~~(99)"Distillate Fuel No. 2" has a minimum and maximum distillation temperature of 540 F and 640 F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

~~(74)~~(100)"Distillate Fuel No. 4" is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131 F.

~~(75)~~(101)"Distillate Fuel Oil" means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term "distillate fuel oil" includes kerosene, kerosene-type jet fuel, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

(102) "District Heating Facility" means a facility that, at a central plant, produces hot water, steam and/or chilled water that is distributed through underground pipes to buildings and facilities connected to the system that are not part of the same facility. District Heating Facility does not include a facility that produces electricity.

~~(76)~~(103)"Dolime" is calcined dolomite.

~~(77)~~(104)"Dry Gas" means a natural gas that is produced from gas wells not associated with the production of crude oil.

(105) "Ductile iron pipe" means pipe made of cast ferrous material in which a major part of the carbon content occurs as free graphite in a substantially nodular or spherroidal form. Pipes are used mainly to convey substances which can flow.

~~(78)~~(106)"Early Action Offset Credit" means a tradable credit issued by an Early Action Offset Program that represents a GHG reduction or GHG removal enhancement equivalent to one metric ton of CO_2e and meets the requirements of section 95990(c).

~~(79)~~(107)"Early Action Offset Program" means a program that meets the requirements of section 95990(a) and is approved by ARB.

~~(80)~~(108)"Early Action Offset Project" means an offset project that is registered with an Early Action Offset Program and has been issued early action offset credits.

(109) "Early Action Reporting Period" means a reporting period in which GHG reductions and/or GHG removal enhancements are reported under an Early Action Offset Program.

~~(81)~~(110) "Early Action Verification Report" means a verification report submitted to an Early Action Offset Program that covers GHG reductions or GHG removal enhancements achieved by an early action offset project over a specific time period.

~~(82)~~(111)"Electric Arc Furnace" or "EAF" means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes. Furnaces that continuously feed direct-reduced iron ore pellets as the primary source of iron are not affected facilities within the scope of this definition.

~~(83)~~(112)"Electrical Distribution Utility(ies)" means an entity that owns and/or operates an electrical distribution system, including: 1) a public utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility or IOU); or 2) a local publicly owned electric utility (POU) as defined in Public Utilities Code section 224.3 or 3) an Electrical Cooperative

(COOP) as defined in Public Utilities Code section 2776, that provides electricity to retail end users in California.

~~(84)~~(113)"Electricity Generating Facility" means a facility that generates electricity and includes one or more generating units at the same location.

~~(85)~~(114)"Electricity Importers" deliver imported electricity. For electricity that is scheduled with a NERC E-Tag to a final point of delivery inside the state of California, the electricity importer is identified on the NERC E-Tag as the purchasing-selling entity (PSE) on the last segment of the 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. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of ARB under this article, and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA) and California Department of Water Resources (DWR). Electricity Importers include EIM Participating Resource Scheduling Coordinators serving the EIM market whose transactions result in electricity imports into California.

~~(86)~~(115)"Eligible Renewable Energy Resource" has the same meaning as defined in Section 399.12 of the Public Utilities Code.

~~(87)~~(116)"Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids. In the context of offsets, "emissions" means the release of greenhouse gases into the atmosphere from sources and processes within an offset project boundary.

~~(88)~~(117)"Emissions Data Report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by MRR. The emissions data report is for the submission of required data for

the calendar year prior to the year in which the report is due. For example, a 2013 emissions data report would cover emissions and product data for the 2013 calendar year and would be reported in 2014.

~~(89)~~(118)"Emissions Efficiency Benchmark" or "GHG emissions efficiency benchmark" means a performance standard used to evaluate GHG emissions efficiency between and amongst similar facilities or operations in the same industrial sector.

(119) "Emulsion" means a mixture of water, crude oil, associated gas, and other components from the oil extraction process that is transferred from an existing platform that is permanently affixed to the ocean floor and that is located outside the distance specified in the "offshore" definition in section 95102 of MRR, to an onshore petroleum and natural gas production facility.

~~(90)~~(120)"End User" means a final purchaser of an energy product, such as electricity, thermal energy, or natural gas not for the purposes of retransmission or resale. In the context of natural gas consumption, an "end user" is the point to which natural gas is delivered for consumption.

(121) "Energy Imbalance Market" "or "EIM" means the operation of the CAISO's real time market to manage transmission congestion and optimization procurement of energy to balance supply and demand for the combined CAISO and EIM footprint.

(122) "Energy Imbalance Market Participating Resource Scheduling Coordinator" or "EIM" Participating Resource Scheduling Coordinator means the participating resource owner or operator, or a third-party designated by the resource owner or operator, that is certified by the CAISO and enters into the pro forma EIM Participating Resource Scheduling Coordinator Agreement, under which it is responsible for meeting the requirements specified in the CAISO Tariff on behalf of the resource owner or operator.

~~(91)~~(123)"Enforceable" means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

~~(92)~~(124)"Enhanced Oil Recovery" or "EOR" means the use of certain methods such as steam (thermal EOR), water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR also applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

~~(93)~~(125)"Enterer" means an entity that imports, into California, motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel, or non exempt biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import into California, if the fuel is not subject to federal customs law. Only enterers that import the fuels specified in this definition outside the bulk transfer/terminal system are subject to reporting under the regulation.

~~(94)~~(126)"Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

~~(95)~~(127)"Environmental Impact Assessment" means a detailed public disclosure statement of potential environmental and socioeconomic impacts associated with a proposed project. Such disclosure is a matter of public record and provides detailed information to public agencies and the general public about the effect that a proposed project is likely to have on the environment and ways in which the significant effects of such a project might be minimized, and to indicate alternatives to such a project.

(128) "Evaporated milk" means the liquid food obtained by partial removal of water only from milk. It contains not less than 6.5 percent by weight of milkfat, not less than 16.5 percent by weight of milk solids not fat, and not less than 23 percent by weight of total milk solids. Evaporated milk contains added vitamin D as prescribed by paragraph (b) of this section. It is homogenized. It is sealed in a container and so processed by heat, either before or after sealing, as to prevent spoilage.

(129) "Exchange" means a central marketplace with established rules and regulations where buyers and sellers meet to conduct trades.

(130) "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.

~~(96)~~(131)"Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

~~(97)~~(132)"Exported Electricity" shall have the same meaning ascribed in section 95102(a) of MRR.

~~(98)~~(133)"External Greenhouse Gas Emissions Trading System" or "External GHG ETS" means an administrative system, other than the California Cap-and-Trade Program, that controls greenhouse gas emissions from sources in its program.

~~(99)~~(134) (A) "Facility," unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95802(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. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(B) "Facility," with respect to natural gas distribution for the purposes of sections 95150 through 95158 of MRR, means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

(C) "Facility," with respect to onshore petroleum and natural gas production for the purposes of sections 95150 through 95158 of MRR,

means all petroleum and natural gas equipment on a well-pad, or associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in section 95102(a) of MRR. When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

~~(100)~~(135)"Fiberglass Glass Pulled" means the quantity of glass removed from the melting furnace in the fiberglass manufacturing process where "Fiberglass" is defined as insulation products for thermal, acoustic and fire applications manufactured using glass.

~~(101)~~(136)"Final Point of Delivery" means the sink specified on the NERC e-Tag, where defined points 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 final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

~~(102)~~(137)"First Deliverer of Electricity" or "First Deliverer" means the owner or operator of an electricity generating facility in California or an electricity importer.

~~(103)~~(138)"First Point of Receipt" means the 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. 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.

~~(104)~~(139)"Flash Point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

~~(105)~~(140)"Flat Glass Pulled" means the quantity of glass removed from the melting furnace in the flat glass manufacturing process where "flat glass" is defined as glass initially manufactured in a sheet form.

~~(106)~~(141)"Fluorinated Greenhouse Gas" means sulfur hexafluoride (SF6), nitrogen trifluoride (NF3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 C. With these exceptions, "fluorinated GHG" includes any hydrofluorocarbon; any perfluorocarbon; any fully fluorinated linear, branched, or cyclic alkane, ether, tertiary amine, or aminoether; any perfluoropolyether; and any hydrofluoropolyether.

~~(107)~~(142)"Fluting" means the center segment of corrugated shipping containers, being faced with linerboard (testliner/kraftliner) on both sides. Fluting covers mainly papers made from recycled fiber but this group also holds paperboard that is made from chemical and semichemical pulp.

~~(108)~~(143)"Forest Buffer Account" means a holding account for ARB offset credits issued to forest offset projects. It is used as a general insurance mechanism against unintentional reversals, for all forest offset projects listed under a Compliance Offset Protocol.

~~(109)~~(144)"Forest Owner" means the owner of any interest in the real (as opposed to personal) property involved in a forest offset project, excluding government agency third party beneficiaries of conservation easements. Generally, a Forest Owner is the owner in fee of the real property involved in a forest offset project. In some cases, one entity may be the owner in fee while another

entity may have an interest in the trees or the timber on the property, in which case all entities or individuals with interest in the real property are collectively considered the Forest Owners, however, a single Forest Owner must be identified as the Offset Project Operator.

~~(110)~~(145)"Fossil Fuel" means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

~~(111)~~(146)"Fractionates" means the process of separating natural gas liquids into their constituent liquid products.

(147) "Freshwater diatomite filter aids" means inorganic mineral powders derived by processing freshwater diatomite which is fossilized single-celled algae found in lake beds. Filter aids are used in combination with filtration hardware to enhance filtration performance to separate unwanted solids from fluids.

(148) "Fried potato chip" means a thin slice of potato that is deep fried until crunchy.

~~(112)~~(149)"Fuel" means solid, liquid, or gaseous combustible material. Volatile organic compounds burned in destruction devices are not fuels unless they can sustain combustion without use of a pilot fuel, and such destruction does not result in a commercially useful end product.

~~(113)~~(150)"Fuel Analytical Data" means data collected about fuel usage (including mass, volume, and flow rate) and fuel characteristics (including heating value, carbon content, and molecular weight) to support emissions calculation.

~~(114)~~(151)"Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas including operators of interstate and intrastate pipelines, a supplier of liquefied natural gas, or a supplier of ~~liquid~~ liquefied petroleum gas as specified in MRR.

~~(115)~~(152)"Fugitive Emissions" means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(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.

~~(116)~~(154)"Galvanized Steel Sheet" means steel coated with a thin layer of zinc to provide corrosion resistance for such products as garbage cans, storage tanks, or framing for buildings. Sheet steel normally must be cold-rolled prior to the galvanizing stage.

~~(117)~~(155)"Gas" means the state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

~~(118)~~(156)"Gaseous Hydrogen" means hydrogen in a gaseous state.

~~(119)~~(157)"Geologic Sequestration" means the process of injecting CO_2 captured from an emissions source into deep subsurface rock formations for long-term storage.

~~(120)~~(158)"Global Warming Potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

(159) "Granulated refined sugar" means white refined sugar (99.9% sucrose), made by dissolving and purifying raw sugar then drying it to prevent clumping.

(160) "Grape Juice concentrate" means the liquid from crushed grapes, botanical genus "Vitas", processed to remove water.

~~(121)~~(161)"Greenhouse Gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrogen trifluoride (NF_3), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

~~(122)~~(162)"Greenhouse Gas Emission Reduction" or "GHG Emission Reduction" or "Greenhouse Gas Reduction" or "GHG Reduction" means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

~~(123)~~(163)"Greenhouse Gas Emissions Source" or "GHG Emissions Source" means, in the context of offset credits, any type of emitting activity that releases greenhouse gases into the atmosphere.

~~(124)~~(164)"Greenhouse Gas Removal" or "GHG Removal" means the calculated total mass of a GHG removed from the atmosphere over a specified period of time.

~~(125)~~(165)"Greenhouse Gas Removal Enhancement" or "GHG Removal Enhancement" means a calculated increase in GHG removals relative to a project baseline.

~~(126)~~(166)"Greenhouse Gas Reservoir" or "GHG Reservoir" means a physical unit or component of the biosphere, geosphere, or hydrosphere with the capability to store, accumulate, or release a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

~~(127)~~(167)"Greenhouse Gas Sink" or "GHG Sink" means a physical unit or process that removes a GHG from the atmosphere.

(168) "Gypsum" means a very soft sulfate mineral composed of calcium sulfate dihydrate, with the chemical formula $CaSO_4 \cdot 2H_2O$.

~~(128)~~(169)"HD-5" or "Special Duty Propane" has the same meaning as contained in MRR.

~~(129)~~(170)"HD-10" has the same meaning as contained in MRR.

~~(130)~~(171)"Heavy Crude Oil" means a category of crude oil characterized by relatively high viscosity, a higher carbon-to-hydrogen ratio, and a relatively higher density having an API gravity of less than 20.

~~(131)~~(172)"Hold" in the context of a compliance instrument, is to have the serial number assigned to that instrument registered into an account assigned to an entity that is registered into the California Cap-and-Trade Program or an External Greenhouse Gas Emissions Trading System to which California has linked its Cap-and-Trade Program pursuant to subarticle 12, or an account under the control of the Executive Officer.

(173) "Holding Account" or "General Holding Account" means an account created for each covered entity, opt-in covered entity, or voluntarily associated entity to hold compliance instruments.

~~(132)~~(174)"Horsepower Tested" means the total horsepower of all turbine and generator set units tested prior to sale.

~~(133)~~(175)"Hot Rolled Steel Sheet" means steel produced from the rolling mill that reduces a hot slab into a coil of specified thickness at a relatively high temperature.

~~(134)~~(176)"Hydrocarbon" means a chemical compound containing predominantly carbon and hydrogen.

~~(135)~~(177)"Hydrofluorocarbon" or "HFC" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

~~(136)~~(178)"Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; it exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

~~(137)~~(179)"Imported Electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into the state of California from a facility or unit physically located outside the state of California with the first point of interconnection into a California balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, defined pursuant to MRR section 95102(a). Imported electricity does not include electricity imported into the CAISO balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the

state of California. 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 Electric Reliability Corporation or Western Electricity Coordinating Council. Imported electricity shall 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

(180) "Industrial Sector Legacy Contract Counterparty" or "Legacy Contract Counterparty" means an entity that has been identified under industrial allocation pursuant to Table 8-1 to receive allowance allocation, and has a contract to purchase Qualified Thermal Output and/or electricity from a Legacy Contract Generator.

~~(138)~~(181)"Initial Crediting Period" means the crediting period that begins with the date that the first GHG emission reductions or GHG removal enhancements took place according to the first Positive Offset or Qualified Positive Offset Verification Statement that is received by ARB.

~~(139)~~(182)"Intentional Reversal" means any reversal caused by a forest owner's negligence, gross negligence, or willful intent, including harvesting, development, and harm to the area within the offset project boundary.

~~(141)~~(183)"Interstate Pipeline" means any entity that owns or operates a natural gas pipeline delivering natural gas to consumers in the state and is subject to rate regulation by the Federal Energy Regulatory Commission.

~~(140)~~(184)"Intrastate Pipeline" means any pipeline wholly within the state of California that is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission.

~~(142)~~(185)"Inventory Position" means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

~~(143)~~(186)"Issue" or "Issuance" means, in the context of offset credits, the creation of ARB offset credits or registry offset credits equivalent to the number of verified GHG reductions or GHG removal enhancements for an offset project over a specified period of time. In the context of allowances, issue means the placement of an allowance into an account under the control of the Executive Officer.

~~(144)~~(187)"Joint Powers Agency(ies)" or "JPA" means an public agency that is formed and created pursuant to the provisions of Government Code sections 6500. et seq.

~~(145)~~(188)"Kerosene" is a light petroleum distillate with a maximum distillation temperature of 400 F at the 10-percent recovery point, a final maximum boiling point of 572 F, a minimum flash point of 100 F, and a maximum freezing point of -22 F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. Kerosene does not include kerosene-type jet fuel.

~~(146)~~(189)"Kerosene-Type Jet Fuel" means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Included are Jet A, Jet A–1, JP–5, and JP–8.

(190) "Lactose (Milk Sugar)" means a white to creamy white crystalline product, possessing a mildly sweet taste. It may be anhydrous, contain one molecule of water of hydration, or be a mixture of both forms.

(191) "Lager beer" means beer produced with bottom fermenting yeast strains, Saccharomyces uvarum (or carlsbergensis) at colder fermentation temperatures than ales.

(192) "Lead and lead alloys" means lead or the metal alloy that combines lead and other elements such as antimony, selenium, arsenic, copper, tin or calcium.

~~(147)~~(193)"Lead Verifier" means, for purposes of this article, a person that has met all of the requirements in section 95132(b)(2) of MRR and who may act as the lead verifier of an offset verification team providing offset verification services or as a lead verifier providing an independent review of offset verification services rendered.

~~(148)~~(194)"Lead Verifier Independent Reviewer" or "Independent Reviewer" means, for purposes of this article, a lead verifier within a verification body who has not participated in conducting offset verification services for an Offset Project Developer or Authorized Project Designee for the current Offset Project Data Report and who provides an independent review of offset verification services rendered for an Offset Project Developer or Authorized Project Designee as required in section 95977.1(b)(3)(R). The independent reviewer is not required to also meet the requirements for a sector specific or offset project specific verifier.

(195) "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 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 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 gave rise to 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.

(196) "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 Legacy Contract 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.

(197) "Legacy Contract Generator" means a covered entity that generates and sells electricity or thermal energy subject to one or more legacy contracts.

(198) "Legacy Contract Qualified Thermal Output" means the thermal energy that is sold to specific end-users, and reported pursuant to MRR section 95112(a)(5)(A), and the used to produce cooling energy (e.g., chilled water) if the facility provides to a particular end-user outside of the facility boundary pursuant to MRR 95112(A)(5)(C)(1). Legacy Contract Qualified Thermal Output also includes any thermal energy generated by equipment that is not an integral part of the cogeneration unit, for example the auxiliary boiler, that is provided to a Legacy Contract Counterparty and meets the eligibility requirements in section 95894. Legacy Contract Qualified Thermal Output does not include thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations.

~~(149)~~(199)"Less Intensive Verification" means, for the purposes of this article, the offset verification services provided in interim years between full verifications of an Offset Project Data Report; less intensive verification of an Offset Project Data Report only requires data checks and document reviews of an Offset Project Data Report based on the analysis and risk assessment in the most current sampling plan developed as part of the most recent full offset

verification services. This level of verification may only be used if the offset verifier can provide findings with a reasonable level of assurance.

~~(150)~~(200)"Light Crude Oil" means a category of crude oil characterized by relatively low viscosity, a lower carbon-to-hydrogen ratio, and a relatively lower density having an API gravity of greater than or equal to 20.

~~(151)~~(201)"Limited Use Holding Account" means an account in which allowances are placed after an entity qualifies for a direct allocation under section 95890(b). Allowances placed in this account can only be removed for consignment to the auction pursuant to section 95831(a)(3).

~~(152)~~(202)"Linkage" means the approval of compliance instruments from an external greenhouse gas emission trading system (GHG ETS) to meet compliance obligations under this article, and the reciprocal approval of compliance instruments issued by California to meet compliance obligation in an external GHG ETS.

~~(153)~~(203)"Liquefied Hydrogen" means hydrogen in a liquid state.

(204) "Liquefied natural gas" or "LNG" means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

~~(154)~~(205)"Liquefied Petroleum Gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG is primarily mixtures of propane, butane, propene (propylene) and ethane. The most common specification categories are propane grades, HD-5, HD-10, and commercial grade propane. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as propane.

(206) "Liquid Color Concentrate" means a fluid extract from fruits and vegetables reduced by driving off water whose uses are for altering the color of materials and/or food.

~~(155)~~(207)"Listed Industrial Sector" means covered industrial sectors that are eligible for industry assistance specified in Table 8-1 of subarticle 8.

~~(156)~~(208)"Long-Term Contract" means a contract for the delivery of electricity entered into before January 1, 2006, for the term of five years or more.

~~(157)~~(209)"Mandatory Reporting Regulation" or "MRR" means ARB's 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).

~~(158)~~(210)"Market Index" means any published index of quantities or prices based on results of market transactions.

~~(160)~~(211)"Market-Shifting Leakage," in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset project's boundary due to the effects of an offset project on an established market for goods or services.

~~(159)~~(212)"Marketer" means a purchasing-selling entity that delivers electricity and is not a retail provider.

~~(161)~~(213)"Methane" or "CH_4" means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

~~(162)~~(214)"Metric Ton" or "MT" means a common international measurement for mass, equivalent to 2,204.6 pounds or 1.1 short tons.

(215) "Milk" means the lacteal secretion, practically free from colostrum, obtained by the complete milking of one or more healthy cows. Milk that is in final package form for beverage use shall have been pasteurized or ultrapasteurized, and shall contain not less than 8 1/4 percent milk solids not fat and not less than 3 1/4 percent milkfat. Milk may have been adjusted by separating part of the milkfat therefrom, or by adding thereto cream, concentrated milk, dry whole milk, skim milk, concentrated skim milk, or nonfat dry milk. Milk may be homogenized.

~~(163)~~(216)"Mixed Crude Oil" means a mix of both heavy and light crude oil.

~~(164)~~(217)"Monitoring" means, in the context of offset projects, the ongoing collection and archiving of all relevant and required data for determining the project baseline, project emissions, and quantifying GHG reductions or GHG removal enhancements that are attributable to the offset project.

~~(165)~~(218)"Motor Gasoline (finished)" has the same definition as MRR.

~~(166)~~(219)"Multi-Jurisdictional Retail Provider" means a retail provider that provides electricity to consumers in California and in one or more other states in a contiguous service territory or from a common power system.

~~(167)~~(220)"Municipal Solid Waste" or "MSW" means solid-phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials. Insofar as there is separate collection, processing, and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), paper, clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. §6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.

~~(168)~~(221)"Natural Gas" means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons, and carbon dioxide. Natural gas may be field quality (which varies widely) or pipeline quality. For the purposes of this rule, the

definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

~~(169)~~(222)"Natural Gas Liquids" or "NGLs", means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Generally, such liquids consist of ethane, propane, butanes, pentanes, and higher molecular weight hydrocarbons. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(223) "Natural gas supplier" or "supplier of natural gas" means any entity that distributes or uses natural gas in California and is described below:
(1) A public utility gas corporation operating in California;
(2) A publicly owned natural gas utility operating in California; or
(3) The operator of an intrastate pipeline not included in section 95802(a)(1) or section 95802(a)(2) that distributes natural gas directly to end users.
For the purposes of this article, an interstate pipeline is not a natural gas supplier.

~~(170)~~(224)"NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

~~(171)~~(225)"Nitric Acid" means HNO_3 of 100% purity.

~~(172)~~(226)"Non-exempt Biomass derived CO_2" means CO_2 emissions resulting from the combustion of fuel not listed under section 95852.2(a), or that is not verifiable under section 95131(i) of MRR.

(227) "Non-thermal enhanced oil recovery" or "non-thermal EOR" means the process of using methods other than thermal EOR, which may include water flooding or CO2 injection, to increase the recovery of crude oil from a reservoir.

~~(173)~~(228)"Notice of Delegation" means a formal notice used to delegate authority to make an electronic submission to the accounts administrator.

~~(174)~~(229)"Offset Material Misstatement" means a discrepancy, omission, misreporting, or aggregation of the three, identified in the course of offset verification services that leads an offset verification team to believe that an Offset Project Data Report contains errors resulting in an overstatement of the reported total GHG emission reductions or GHG removal enhancements greater than 5.00 percent. Discrepancies, omissions, or misreporting, or an aggregation of the three, that result in an understatement of total reported GHG emission reductions or GHG removal enhancements in the Offset Project Data Report is not an offset material misstatement.

~~(175)~~(230)"Offset Project" means all equipment, materials, items, or actions that are directly related to or have an impact upon GHG reductions, project emissions, or GHG removal enhancements within the offset project boundary.

~~(176)~~(231)"Offset Project Boundary" is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

~~(177)~~(232)"Offset Project Commencement" means, unless otherwise specified in a Compliance Offset Protocol, 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. For an offset project that involves the implementation of a management activity, "offset project commencement" means, unless otherwise specified in a Compliance Offset Protocol, the date on which such activity is first implemented.

~~(178)~~(233)"Offset Project Data Report" means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the

information and documentation required by this article or a Compliance Offset Protocol.

~~(179)~~(234)"Offset Project Operator" means the entity(ies) with legal authority to implement the offset project.

~~(180)~~(235)"Offset Project Registry" means an entity that meets the requirements of section 95986 and is approved by ARB that lists offset projects, collects Offset Project Data Reports, facilitates verification of Offset Project Data Reports, and issues registry offset credits for offset projects being implemented using a Compliance Offset Protocol.

~~(181)~~(236)"Offset Protocol" means a documented set of procedures and requirements to quantify ongoing GHG reductions or GHG removal enhancements achieved by an offset project and calculate the project baseline. Offset protocols specify relevant data collection and monitoring procedures, emission factors, and conservatively account for uncertainty and activity-shifting and market-shifting leakage risks associated with an offset project.

~~(182)~~(237)"Offset Verification" means a systematic, independent, and documented process for evaluation of an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report against ARB's Compliance Offset Protocols and this article for calculating and reporting project baseline emissions, project emissions, GHG reductions, and GHG removal enhancements.

~~(183)~~(238)"Offset Verification Services" means services provided during offset verification as specified in sections 95977.1 and 95977.2, including reviewing an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report, verifying its accuracy according to the standards specified in this article and applicable Compliance Offset Protocol, assessing the Offset Project Operator's or Authorized Project Designee's compliance with this article and applicable Compliance Offset Protocol, and submitting an Offset Verification Statement to ARB or an Offset Project Registry.

~~(184)~~(239)"Offset Verification Statement" means the final statement rendered by a verification body attesting whether an Offset Project Operator's or Authorized Project Designee's Offset Project Data Report is free of an offset material misstatement, and whether the Offset Project Data Report conforms to the requirements of this article and applicable Compliance Offset Protocol.

~~(185)~~(240)"Offset Verification Team" means all of those working for a verification body, including all subcontractors, to provide offset verification services for an Offset Project Operator or Authorized Project Designee.

~~(186)~~(241)"Operational Control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health, and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

~~(187)~~(242)"Operator" means the entity, including an owner, having operational control of a facility, or other entity from which an emissions data report is required under article 2, section 95104, title 17, Greenhouse Gas Emissions Data Report. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

~~(188)~~(243)"Opt-in Covered Entity" means an entity that meets the requirements of 95811 that does not exceed the inclusion thresholds set forth in section 95812 and may elect to voluntarily opt-in to the Cap-and-Trade Program and be willing to be subject to the requirements set forth in this article.

(244) "Over-the-Counter" means the trading of carbon compliance instruments, contracts, or other instruments not listed on any exchange.

~~(189)~~(245)"Oxidation" means a reaction in which the atoms in an element lose electrons and the valence of the element is correspondingly increased.

~~(190)~~(246)"Ozone Depleting Substances" or "ODS" means a compound that contributes to stratospheric ozone depletion.

~~(191)~~(247)"Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

~~(192)~~(248)"Permanent" means, in the context of offset credits, either that GHG reductions and GHG removal enhancements are not reversible, or when GHG reductions and GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions and GHG removal enhancements to ensure that all credited reductions endure for at least 100 years.

~~(193)~~(249)"Permanent Retirement Registry" means the publicly available registry in which the Executive Officer will record the ~~serial numbers of the~~ retired compliance instruments.

~~(194)~~(250)"Petroleum" means oil removed from the earth and the oil derived from tar sands, and/or shale.

~~(195)~~(251)"Petroleum Refinery" or "Refinery" means any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through re-distillation, cracking, or reforming of unfinished petroleum derivatives. Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

~~(196)~~(252)"Pickled Steel Sheet" means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides.

~~(197)~~(253)"Pipeline Quality Natural Gas" means, for the purpose of calculating emissions under MRR, natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent (90%) methane by volume, and which is less than five percent (5%) carbon dioxide by volume.

(254) "Pistacho" means means the nuts of the pistachio tree of the genus *Pistacia vera* grown in the production area whether inshell or shelled.

~~(198)~~(255)"Plaster" is calcined gypsum that is produced and sold as a finished product and is not used in the production of plasterboard at the same facility.

~~(199)~~(256)"Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.

~~(200)~~(257)"Point of Delivery" or "POD" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

~~(201)~~(258)"Point of Receipt" or "POR" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

~~(202)~~(259)"Portable" means designed and capable of being carried or moved from one location to another. Indications of portability include wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(A) The equipment is attached to a foundation;

(B) The equipment or a replacement resides at the same location for more than 12 consecutive months;

(C) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year; or

(D) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

~~(203)~~(260)"Position Holder" means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected

in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal. "Position holder" does not include inventory held outside of a terminal, fuel jobbers (unless directly holding inventory at the terminal), retail establishments, or other fuel suppliers not holding inventory at a fuel terminal.

~~(204)~~(261)"Positive Emissions Data Verification Statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

~~(206)~~(262)"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 and that the Offset Project Data Report conforms to the requirements of this article and applicable Compliance Offset Protocol.

~~(205)~~(263)"Positive Product Data Verification Statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and that the product data conforms to the requirements of MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

(264) "Poultry deli product" means the products that contain a significant portion of pre-processed poultry and are prepared for human consumption (with or without additional cooking required), including sausages and corn dogs.

~~(207)~~(265)"Power" means electricity, except where the context makes clear that another meaning is intended.

(266) "Powdered milk" means the manufactured dairy product made by evaporating milk to dryness.

(267) "Power contract" shall have the same meaning ascribed in section 95102(a) of MRR.

(268) "Pretzel" is a type of baked bread product made from dough made into a desired shape. The dough is then passed through a caustic hot water bath and then baked in an oven.

~~(208)~~(269)"Primary Account Representative" means an individual authorized by a registered entity through the registration process outlined in section 95832 to make submissions to the Executive Officer and the tracking system in all matters pertaining to this article that legally bind the authorizing entity.

~~(209)~~(270)"Primary Refinery Products" means aviation gasoline, motor gasoline (finished), kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. For the purpose of calculating this value for each refinery ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

~~(210)~~(271)"Primary Residence" means the property an individual uses as a residence the majority of the time during the year or as the principal place of abode of the individual's family members. The primary residence may be documented by the address listed on the individual's federal and state tax returns, driver's license, automobile registration, or voter registration card.

~~(211)~~(272)"Proceeds" means monies generated as a result of an auction or from sales from the Allowance Price Containment Reserve.

~~(212)~~(273)"Process" means the intentional or unintentional reactions between substances or their transformation, including the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

~~(213)~~(274)"Process Emissions" means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in

an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

~~(214)~~(275)"Process Unit" means the equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final or intermediate product used in the onsite production of other products. The process unit also includes the purification of recovered byproducts.

~~(215)~~(276)"Producer" means a person who owns leases, operates, controls, or supervises a California production facility.

~~(216)~~(277)"Product Data Verification Statement" means the final statement rendered by a verification body attesting whether a reporting entity's product data in their covered emissions data report is free of material misstatement, and whether the product data conforms to the requirements of the MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

~~(217)~~(278)"Professional Judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

~~(218)~~(279)"Project Baseline" means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or GHG removal enhancements for the offset project's GHG emission sources, GHG sinks, or GHG reservoirs within the offset project boundary.

~~(219)~~(280)"Project Emissions" means any GHG emissions associated with the implementation of an offset project that must be accounted for in the Offset Project Data Report.

~~(220)~~(281)"Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

~~(221)~~(282)"Property Right" means any type of right to specific property whether it is personal or real property, tangible or intangible.

(283) "Protein meal" means rendered product from poultry tissues including meat, viscera, bone, blood, and feathers.

(284) "Public Service Facility" 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 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 education facility, and may also provide electricity to its own facilities or for sale to an electrical distribution utility.

~~(222)~~(285)"Public Utility Gas Corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

~~(223)~~(286)"Publicly Owned Natural Gas Utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(287) "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), that uses electricity to convey wholesale water supplies and has a compliance obligation for each data year from 2013 to 2020.

~~(224)~~(288)"Purchase Limit" means the maximum percentage of allowances that may be purchased by an entity of a group of affiliated entities at an allowance auction.

~~(225)~~(289)"Purchasing-Selling Entity" or "PSE" means the same meaning as ascribed in MRR.

~~(226)~~(290)"Qualified Export" means electricity that is exported in the same hour as imported electricity and documented by NERC E-tags. When imports are not documented on NERC E-tags, because a facility or unit located outside the state of California has a first point of interconnection with a California balancing authority area, the reporting entity may demonstrate hourly

~~electricity~~electricity delivery consistent with the record keeping requirements of the California balancing authority area, including records of revenue quality meter data, invoices, or settlements data. Only electricity exported within the same hour and by the same importer as the imported electricity is a qualified export. It is not necessary for the imported and exported electricity (as defined in the MRR) to enter or leave California at the same intertie. Qualified exports shall not result in a negative compliance obligation for any hour.

~~(228)~~(291)"Qualified Positive Emissions Data Verification Statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9) of MRR, but the emissions data may include one or more other nonconformance(s) with requirements of MRR which do not result in a material misstatement. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

~~(227)~~(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 the 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. 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.

~~(229)~~(293)"Qualified Positive Product Data Verification Statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and is in

conformance with section 95131(b)(9) of MRR, but the product data may include one or more other nonconformance(s) with the requirements of MRR which do not result in a material misstatement. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

(294) "Qualified Thermal Output" means the thermal energy generated by a cogeneration unit or district heating facility that is sold to particular end-users and reported pursuant to MRR section 95112(a)(5)(A) and the thermal energy used on-site by industrial processes or operations and heating and cooling operations that is not in support of or a part of the electricity generation or cogeneration system and is reported pursuant to MRR sections 95112(a)(5)(C). Qualified thermal output does not include thermal energy that is vented, radiated, wasted, or discharged before it is utilized at industrial processes or operations, for a facility with a cogeneration unit, or any thermal energy generated by equipment that is not an integral part of the cogeneration unit.

~~(230)~~(295)"Quantifiable" means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or GHG removal enhancements relative to a project baseline in a reliable and replicable manner for all GHG emission sources, GHG sinks, or GHG reservoirs included within the offset project boundary, while accounting for uncertainty and activity-shifting leakage and market-shifting leakage.

~~(231)~~(296)"Quantitative Usage Limit" means a limit on the percentage of an entity's compliance obligation that may be met by surrendering offset credits, sector-based credits, or other compliance instruments designated to be subject to the limit under this article.

~~(232)~~(297)"Rack" means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

~~(233)~~(298)"Radiative Forcing" means the change in the net vertical irradiance at the atmospheric boundary between the troposphere and the stratosphere due to

an internal change or a change in the external forcing of the climate system such as a change in the concentration of carbon dioxide or the output of the Sun.

~~(234)~~(299)"Real" means, in the context of offset projects, that GHG reductions or GHG enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate, and conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

~~(235)~~(300)"Reasonable Assurance" means a high degree of confidence that submitted data and statements are valid.

~~(236)~~(301)"Recycled Boxboard" means containers of solid fiber made from recycled fibers, including cereal boxes, shoe boxes and protective paper packaging for dry foods. It also includes folding paper cartons, set-up boxes, and similar boxboard products. Recycled boxboard is made from recycled fibers.

~~(237)~~(302)"Recycled Linerboard" means types of paperboard made from recycled fibers that meet specific tests adopted by the packaging industry to qualify for use as the outer facing layer for corrugated board, from which shipping containers are made.

~~(238)~~(303)"Recycled Medium" means the center segment of corrugated shipping containers, being faced with linerboard on both sides. Recycled medium is made from recycled fibers.

~~(239)~~(304)"Reference Level" means the quantity of GHG emission equivalents that have occurred during the normal course of business or activities during a designated period of time within the boundaries of a defined sector and a defined jurisdiction.

~~(240)~~(305)"Reformulated Gasoline Blendstock for Oxygenate Blending" or "RBOB" has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

~~(241)~~(306)"Register," in the context of a compliance instrument, means the act of ~~entering~~assigning the serial number of a compliance instrument into an account.

~~(242)~~(307)"Registrant" or "Registered Entity" means an entity that has completed the process for registration.

~~(243)~~(308)"Registry Offset Credit" means a credit issued by an Offset Project Registry for a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable, permanent, verifiable, and enforceable and may only be issued for offset projects using Compliance Offset Protocols. Pursuant to section 95981.1, ARB may determine that a registry offset credit may be removed, retired, or cancelled from the Offset Project Registry system and issued as an ARB offset credit.

~~(244)~~(309)"Registry Services" means all services provided by an ARB approved Offset Project Registry in section 95987.

~~(245)~~(310)"Renewable Energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

~~(246)~~(311)Renewable Energy Credit" or "REC" has the same meaning as defined in the California Energy Commission's "Renewable Portfolio Standard Eligibility, 7th edition, Commission Guidebook, April, 2013; CEC-300-2013-005-ED7-CMF. ~~"Renewable Energy Credit" or "REC" means a certificate of proof, issued through the accounting system established by the California Energy Commission pursuant to Public Utilities Code Section 399.13, that one megawatt hour of electricity was generated and delivered by an eligible renewable energy resource. As specified in Public Utilities Code Section 399.12, Subdivision (g)(2), a REC includes all renewable and environmental attributes associated with the production of electricity from an eligible renewable energy resource, except for an emissions reduction credit issued pursuant to Section 40709 of the Health and Safety Code and any credits or~~

~~payments associated with the reduction of solid waste and treatment benefits created by the utilization of biomass or biogas fuels.~~

~~(247)~~(312)"Renewable Liquid Fuels" means fuel ethanol, biomass-based diesel fuel, other renewable diesel fuel and other renewable fuels.

~~(248)~~(313)"Reporting Period" means, in the context of offsets, the period of time for which an Offset Project Operator or Authorized Project Designee quantifies and reports GHG reductions or GHG removal enhancements covered in an Offset Project Data Report. The first reporting period for an offset project in an initial crediting period may consist of 6 to 24 consecutive months; all subsequent reporting periods in an initial crediting and all reporting periods in any renewed crediting period must consist of 12 consecutive months. For offset projects developed using the Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011, there may only be one Reporting Period per offset project. The Reporting Period may not be longer than 12 months and there is no minimum timeframe imposed for the Reporting Period.

~~(249)~~(314)"Reporting Year" means data year.

~~(250)~~(315)"Reserve Price" see "Auction Reserve Price."

~~(251)~~(316)"Reserve Sale Administrator" means the operator of sales from the Allowance Price Containment Reserve account, which may be the Executive Officer or an entity designated by the Executive Officer.

~~(252)~~(317)"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).

~~(253)~~(318)"Retail Provider" means an entity that provides electricity to retail end users in California and is an electrical corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

~~(254)~~(319)"Retire" or "Retired" or "Retirement" means that the serial number for a compliance instrument is registered into the Retirement Account under the control of the Executive Officer. Compliance instruments registered into this account cannot be removed.

~~(255)~~(320)"Reversal" means a GHG emission reduction or GHG removal enhancement for which an ARB offset credit or registry offset credit has been issued that is subsequently released or emitted back into the atmosphere due to any intentional or unintentional circumstance.

(321) "Salt" means sodium chloride, determined as chloride and calculated as percent sodium chloride, by the method prescribed in "Official Methods of Analysis of the Association of Official Analytical Chemists," 13th Ed., 1980, sections 32.025 to 32.030, under the heading "Method III (Potentiometric Method)."

(322) "Seamless rolled ring" means a metal product manufactured by punching a hole in a thick, round piece of metal, and then rolling and squeezing (or in some cases, pounding) it into a thin ring. Ring diameters can be anywhere from a few inches to 30 feet.

~~(256)~~(323)"Sector" or "Sectoral," when used in conjunction with sector-based crediting programs, means a group or subgroup of an economic activity, or a group or cross-section of a group of economic activities, within a jurisdiction.

~~(257)~~(324)"Sector-Based Crediting Program" is a GHG emissions-reduction crediting mechanism established by a country, region, or subnational jurisdiction in a developing country and covering a particular economic sector within that

jurisdiction. A program's performance is based on achievement toward an emissions reduction target for the particular sector within the boundary of the jurisdiction.

~~(258)~~(325)"Sector-Based Offset Credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached.

~~(259)~~(326)"Self-Generation of Electricity" means electricity dedicated to serving an electricity user on the same location as the generator. The system may be operated directly by the electricity user or by an entity with a contractual arrangement.

~~(260)~~(327)"Serial Number" means a unique number assigned to each compliance instrument for identification.

~~(261)~~(328)"Sequestration" means the removal and storage of carbon from the atmosphere in GHG sinks or GHG reservoirs through physical or biological processes.

~~(262)~~(329)"Sink" or "sink to load" or "load sink" means the sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

(330) "Skim milk" means the product that results from the complete or partial removal of milk fat from milk.

~~(263)~~(331)"Soda Ash Equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.

~~(264)~~(332)"Solomon Energy Intensity Index®" or "Solomon EII" or "EII" means a petroleum refinery energy efficiency metric that compares actual energy consumption for a refinery with the "standard" energy consumption for a refinery of similar size and configuration. The "standard" energy is calculated based on an analysis of worldwide refining capacity as contained in the database maintained by Solomon Associates. The ratio of a facility's actual energy to the standard energy is multiplied by 100 to arrive at the Solomon

EII for a refinery. "Solomon Energy Review" means a data submittal and review conducted by a petroleum refinery and Solomon Associates. This process uses the refinery energy utilization, throughput and output to determine the Solomon EII of the refinery.

~~(265)~~(333)"Source" means greenhouse gas source; or any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

~~(266)~~(334)"Source of generation" or "generation source" means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, also referred to as the first point of receipt.

~~(267)~~(335)"Specified Source of Electricity" or "Specified Source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract as defined in MRR section 95102(a) to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by ARB.

(336) "Spot" means a contract for the immediate delivery of and payment for a product.

(337) "Stand-Alone-Electricity Generating Facility" has the same meaning in this regulation as in section 95102(a) of MRR.

~~(268)~~(338)"Standing Live Carbon Stocks" means the above ground carbon in live tree biomass. Live trees include the bole, stem, branches, roots, and leaves or needles.

~~(269)~~(339)"Stationary" means neither portable nor self-propelled, and operated at a single facility.

~~(270)~~(340)"Steel Produced Using an Electric Arc Furnace" means steel produced by electric arc furnace or "EAF". EAF means a furnace that produces molten steel and heats the charge materials with electric arcs from carbon electrodes.

~~(271)~~(341)"Supplier" means a producer, importer, exporter, position holder, interstate pipeline operator, or local distribution company of a fossil fuel or an industrial greenhouse gas.

(342) "Sweetened condensed milk" means the food obtained by partial removal of water only from a mixture of milk and safe and suitable nutritive carbohydrate sweeteners. The finished food contains not less than 8 percent by weight of milkfat, and not less than 28 percent by weight of total milk solids. The quantity of nutritive carbohydrate sweetener used is sufficient to prevent spoilage. The food is pasteurized and may be homogenized.

~~(272)~~(343)"Terminal" means a motor vehicle fuel or diesel fuel storage and distribution facility that is supplied by pipeline or vessel, and from which fuel may be removed at a rack. "Terminal" includes a fuel production facility where motor vehicle or diesel fuel is produced and stored and from which fuel may be removed at a rack.

~~(273)~~(344)"Testliner" means types of paperboard that meet specific tests adopted by the packaging industry to qualify for use as the outer facing layer for corrugated board, from which shipping containers are made. Testliner is made primarily from fibers obtained from recycled fibers.

(345) "Thermal enhanced oil recovery" or "thermal EOR" means the process of using injected steam to increase the recovery of crude oil from a reservoir.

~~(274)~~(346)"Tin Plate" means thin sheet steel with a very thin coating of metallic tin. Tin plate also includes Tin Free Steel or TFS which has an extremely thin coating of chromium, metallic, and oxide. Tin plate is used primarily in can making.

~~(275)~~(347)"Tissue" means a class of papers which are characteristically gauzy in texture and, in some cases, fairly transparent. They may be glazed, unglazed, or creped and are used for a variety of purposes. Examples of different types of tissue papers include sanitary grades such as toilet, facial, napkin, towels, wipes, and special sanitary papers.

(348) "Tissue produced adjusted by water absorbency capacity" means the mass of tissue adjusted by water absorbency capacity derived by using the following

metric: Tissue produced adjusted by water absorbency capacity = Air dried ton of tissue produced x grams of water absorbed by a gram of tissue product.

(349) "Tomato soluble solids" means the sucrose value as determined by the method prescribed in the "Official Methods of Analysis of the Association of Official Analytical Chemists," 13th Ed., 1980, sections 32.014 to 32.016 and 52.012. For instances where no salt has been added, the sucrose value obtained from the referenced tables shall be considered the percent of tomato soluble solids. If salt has been added either intentionally or through the application of the acidified break, determine the percent of such added sodium chloride as specified in the definition of salt. Subtract the percentage sodium chloride from the percentage of total soluble solids found (sucrose value from the refractive index tables) and multiply the difference by 1.016. The resultant value is considered the percent of "tomato soluble solids."

(350) "Tracking System" means the Compliance Instrument Tracking System Service where ARB compliance instruments are issued, traded, and retired.

~~(276)~~(351)"Transaction," when referring to an arrangement between registered entities regarding allowances, means an understanding among registered entities to transfer the control of an allowance from one entity to another, either immediately or at a later date.

~~(277)~~(352)"Transfer" of a compliance instrument means the removal ~~of the serial number~~ of a compliance instrument from one account and placement into another account.

~~(278)~~(353)"Transfer Request" means the communication by an authorized account representative or an alternate authorized account representative to the accounts administrator to register into the tracking system the transfer of allowances between accounts.

(354) "Transferred ARB Project" means an offset project which has been transferred from one Offset Project Registry where it was initially listed to another Offset Project Registry. The Offset Project Registry to which the offset project is transferred will indicate the applicable offset project status from the following list: "Proposed Project," "Active ARB Project," "Active

Registry Project," "Proposed Renewal," "Active ARB Renewal," and "Active Registry Renewal."

~~(279)~~(355)"Tribe" means a federally-recognized Indian tribe and any entity created by a federally-recognized Indian Tribe.

(356) "True-up allowance amount" is a quantity of California GHG allowances allocated for changes in production or allocation not properly accounted for in prior allocations pursuant to 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).

~~(280)~~(357)"Unintentional Reversal" means any reversal, including wildfires or disease that is not the result of the forest owner's negligence, gross negligence, or willful intent.

(358) "University Covered Entity" means a facility that meets the definition of an educational facility pursuant to Education Code section 94110(e) and is either a covered entity, or opt-in covered entity starting with the 2015 data year.

~~(281)~~(359)"Unspecified Source of Electricity" or "Unspecified Source" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity.

~~(282)~~(360)"Vented Emissions" means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

~~(283)~~(361)"Verifiable" means that an Offset Project Data Report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

~~(284)~~(362)"Verification Body" means a firm accredited by ARB, which is able to render an offset verification statement and provide offset verification services for Offset Project Operators or Authorized Project Designees subject to providing an Offset Project Data Report under this article.

~~(285)~~(363)"Verifier" or "offset verifier" means an individual accredited by ARB to carry out offset verification services as specified in sections 95977.1 and 95977.2.

~~(286)~~(364)"Vintage Year" means the budget year to which an individual Californian GHG allowance is assigned pursuant to subarticle 6.

~~(287)~~(365)"Voluntarily Associated Entity" or "General Market Participant" means any entity which does not meet the requirements of section 95811 or 95813 in this article and that intends to purchase, hold, sell, or voluntarily retire compliance instruments or an entity operating an offset project or early action offset project that is registered with ARB pursuant to subarticle 13 or 14 in this article.

~~(288)~~(366)"Voluntary Renewable Electricity" or "VRE" means electricity produced or RECs associated with electricity, produced by a voluntary renewable electricity generator, and which has not and will not be sold or used to meet any other mandatory requirements in California or any other jurisdiction.

~~(289)~~(367)"Voluntary Renewable Electricity Aggregator" or "VRE Aggregator" means the entity that is aggregating systems for the purpose of allowance retirement pursuant to section 95841.1.

~~(290)~~(368)"Voluntary Renewable Electricity Generator" means any entity that produces renewable electricity and applies for allowance retirement pursuant to section 95841.1.

~~(291)~~(369)"Voluntary Renewable Electricity Participant" or "VRE Participant" means a voluntary renewable electricity generator, a REC marketer, or entity that purchases voluntary renewable electricity or RECs as an end-user or on behalf of an end-user and is seeking allowance retirement pursuant to section 95841.1.

(370) "Waste-to-Energy Facility" means a facility located in California that combusts eligible municipal solid waste in accordance with a current permit issued by the local Air Pollution Control District or Air Quality Management District, to generate and distribute electricity over the electric power grid for wholesale or retail customers of the grid located in California.

(371) "Water absorption capacity" means mass of water that is absorbed per unit mass of the test piece using the methodology specified by the ISO 12625-8:2010 except for the humidity and temperature condition which shall be 50% relative humidity +/- 2%, and 23C +/-1 C.

(372) "Whey protein concentrate" means the substance obtained by the removal of sufficient nonprotein constituents from pasteurized whey so that the finished dry product contains > 25% protein. WPC is produced by physical separation techniques such as precipitation, filtration or dialysis. The acidity of WPC may be adjusted by the addition of safe and suitable pH adjusting ingredients.

(373) "Whole chicken and chicken parts" means whole chicken or chicken parts (including breasts, thighs, wings) that are bone-in or deboned and packaged for wholesale or retail.

(374) "Whole Peeled Tomatoes" is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. The tomatoes are peeled but kept whole, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

(b) For the purposes of sections 95801 through 96023, the following acronyms apply:

(1) "AB 32" means Assembly Bill 32, the California Global Warming Solutions Act of 2006.

(2) "ARB" means the California Air Resources Board.

(3) "BAU" means business as usual.

(4) "BPA" means Bonneville Power Administration.

(5) "C" means Centigrade

(6) "CAISO" means the California Independent System Operator.

(~~6~~7) "CAR" means Climate Action Reserve.

(~~7~~8) "CEC" means California Energy Commission. ,

(~~8~~9) "CFR" means Code of Federal Regulations.

(~~9~~10) "CH_4" means methane.

(11~~10~~) "CO_2" means carbon dioxide.

(12~~11~~)"CO_2e" means carbon dioxide equivalent.

~~(12) "CRT" means Climate Reserve Tonne.~~

(13) "DWR" means California Department of Water Resources.

(14) "EII" means the Solomon Energy Instensity Index®

(15) "ETS" means Emission Trading System

(16) "F" means Fahrenheit.

(17) "GHG" means greenhouse gas.

(18) "GHG ETS" means greenhouse gas emissions trading system.

(19) "GWP" means global warming potential.

(20) "HFC" means hydrofluorocarbon.

(21) "LPG" means liquefied petroleum gas.

(22) "MMBtu" means one million British thermal units.

(23) "MRR" means the Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(24) "Mscf" means one thousand standard cubic feet.

(25) "MWh" means megawatt-hour.

(26) "MT" means metric tons.

(27) "NAICS" means North American Industry Classification System.

(28) "NGLs" means natural gas liquids.

(29) "NERC" means North American Electric Reliability Corporation.

(30) "N_2O" means "nitrous oxide."

(31) "PFC" means perfluorocarbon.

(32) "PSE" means purchasing-selling entity.

(33) "PUC" means the Public Utilities Commission.

(34) "QE" means Qualified Export as defined in section 95802(a)(~~22~~90)

(35) "REC" means Renewable Energy Credit.

(36) "REDD" means reducing emissions from deforestation and degradation.

(37) "RPS" means the Renewable Portfolio Standard

(38) "SCF" means standard cubic foot.

(39) "SF_6" means sulfur hexafluoride.

(40) "TEAP" means the Technology and Economic Assessment Panel of the Montreal Protocol.

(4041) "WAPA" means Western Area Power Administration.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 3: Applicability

This article applies to all of the entities identified in this subarticle.

§ 95811. Covered Entities.

This article applies to all of the following entities with associated GHG emissions pursuant to section 95812:

(a) Operators of Facilities. The operator of a facility within California that has one or more of the following processes or operations:

(1) Cement production;

(2) Cogeneration;

(3) Glass production;

(4) Hydrogen production;

(5) Iron and steel production;

(6) Lead Production;

(67) Lime manufacturing;

(78) Nitric acid production;

(89) Petroleum and natural gas systems, as specified in section 95852(h);

(910) Petroleum refining;

(1011) Pulp and paper manufacturing;

(1112) Self-generation of electricity; or

(1213) Stationary combustion.

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(g) Suppliers of Liquefied Natural Gas

(1) Operators of liquefied natural gas production facilities that produce liquefied natural gas products from natural gas received from interstate pipelines as described in section 95122 of MRR;

(2) Importers of liquefied natural gas.

(gh) Carbon dioxide suppliers.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95812. Inclusion Thresholds for Covered Entities.

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(b) If an entity's reported or reported and verified annual emissions in any data year from 2009 through ~~2011~~2012 from the categories specified in section 95852(a) equal or exceed the thresholds identified below, that entity is classified as a covered entity as of January 1, 2013, and for all future years until any requirement set forth in section 95812(e) is met.

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(d) If an entity's annual, assigned, or reported and verified emissions from any data year between 2011-2014 equal or exceed the thresholds identified below from the categories specified in sections 95851(a) ~~and ,~~(b),(c), and (d) then that entity is classified as a covered entity as of January 1, 2015, for the year in which the threshold is reached and for all future years until any requirement set forth in section 95812(e) is met.

(1) Fuel Suppliers. The threshold for a fuel supplier is 25,000 metric tons or more of CO_2e annually from the emissions of GHG that would result from full combustion or oxidation of the quantities of the fuels, identified in section 95811(c) through (g)~~(f)~~, which are imported and/or delivered to California.

(2) Electricity importers. The threshold for an electricity importer of specified source of electricity is zero metric tons of CO_2e per year and for unspecified sources is zero MWhs per year as of January 1, 2015.

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(f) If an entity receives a direct allocation of allowances pursuant to section 95870, but ceases all operation or "shuts down" before it incurs a surrender obligation for the entire compliance period, the following shall apply:

(1) Within 30 days of facility shut down the facility operator must inform ARB in writing to close its tracking system account or remain in the cap and trade program as a voluntarily associated entity pursuant to 95814(a)(1);

(2) In the case of facility shut down, a facility must either fulfill its prorated compliance obligation pursuant to subarticle 7 or surrender allowances equivalent to all the directly allocated allowances minus those already used for compliance within the compliance period that the facility shuts down;

(3) If the entity closes its account in the tracking system and there are compliance instruments remaining in the entity's accounts, ARB will auction the allowances pursuant to 95831(c)(4).

(g) If a facility ceases production but does not shut down and has received directly allocated allowances, then the facility shall submit to the Executive Officer for the retirement the number of allowances equivalent to the directly allocated allowances for the corresponding budget years in which it had no production. The submittal for retirement must occur within three years of the production cessation. If the facility is eligible for a true-up equation in section 95891, this provision does not apply.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95813. Opt-In Covered Entities.

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(b) An entity that voluntarily elects to participate in this program under this section must submit its request to the Executive Officer for approval pursuant to section 95830(c) by March 1 of the calendar year immediately preceding the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to this section. The Executive Officer shall evaluate such applications and designate approved applicants as opt-in covered entities.

(c) An entity that voluntarily elects to participate in this program under this section may rescind its request to opt in to the program by October 1 of the calendar year prior to the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to section 95813.

(~~c~~d) An opt-in covered entity is subject to all reporting, verification, enforcement, and compliance obligations that apply to covered entities. An opt-in covered entity's first reporting and verification year shall be the calendar year immediately preceding the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to this section.

(~~d~~e) An opt-in covered entity may be eligible to receive freely allocated allowances subject to subarticles 8 and 9.

(e~~f~~) Opt-in participation shall not affect the allowance budgets set forth in subarticle 6.

(f~~g~~) Opting out. After the end of any given compliance period an opt-in covered entity may choose to opt out of the program provided its annual emission levels for any data year remain below the inclusion thresholds set forth in section 95812. An entity choosing to opt out of the program must either fulfill its compliance obligations as required pursuant to subarticle 7 or surrender allowances equivalent to all the directly allocated allowances it has received from the budget years for the compliance period in question. An opt-in covered entity that wishes to opt-out of this program must apply to the Executive Officer.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95814. Voluntarily Associated Entities and Other Registered Participants.

(a) Voluntarily Associated Entities (VAE). An entity not identified as a covered entity or opt-in covered entity that intends to hold California compliance instruments may apply to the Executive Officer pursuant to section 95830(c) for approval as a voluntarily associated entity.

(1) The following entities may qualify as voluntarily associated entities:

(A) An individual, or an entity that does not meet the requirements of sections 95811 and 95813, that intends to purchase, hold, sell, or voluntarily retire compliance instruments;

(B) An entity operating an offset project or early action offset project that is registered with ARB pursuant to subarticles 13 or 14; or

(C) An entity providing clearing services in which it takes only temporary possession of compliance instruments for the purpose of clearing transactions between two entities registered with the Cap-and-Trade Program. A qualified entity must be a derivatives clearing organization as defined in the Commodities Exchange Act (7 U.S.C § 1a(9)) that is registered with the U.S. Commodity Futures Trading Commission pursuant to the Commodities Exchange Act (7 U.S.C. § 7a-1(a)).

(2) An individual registering as a voluntarily associated entity must have a primary residence in the United States.

(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.

(4) An individual who meets the requirements of section 95814(a)(3) and is already registered in the tracking system must provide the notarized letter from his/her employer no later than January 31, 2015. Failure to provide such a letter by the deadline will result in suspension, modification, or revocation of his/her tracking system account.

(5)~~(3)~~ An entity registering as a voluntarily associated entity must be located in the United States, according to the registration information reported pursuant to section 95830(c).

(6) 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.

(b) Restrictions on Other Registered Participants. ~~(1)~~ The following entities do not qualify to hold compliance instruments and do not~~but may~~ qualify as a Registered Participant:

(1~~A~~) An offset verifier accredited pursuant to section 95978;

(2~~B~~) A verification body accredited pursuant to section 95978;

(3~~C~~) Offset Project Registries; ~~or~~

(4~~D~~) Early Action Offset Programs approved pursuant to subarticle 14~~.~~; or

(5) A MRR verifier accredited pursuant to the MRR.

~~(2) To qualify as a Registered Participant the entity must obtain registration approval from the Executive Officer pursuant to section 95830(c).~~

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 4: Compliance Instruments

§ 95821. Compliance Instruments Issued by Approved Programs.

The following compliance instruments may be used to meet a compliance obligation under this article:

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(d) Sector-based offset credits recognized pursuant to subarticle 14; ~~and~~

(e) Compliance instruments specified in sections 95821(b) through (d) are subject to the quantitative usage limit set forth in section 95854~~.~~; and

(f) Other compliance instruments:

(1) Early Reduction Allowances issued by Quebec.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 5: Registration and Accounts

§ 95830. Registration with ARB.

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(b) Eligibility and Restrictions:

(1) 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 in the direct corporate association must register pursuant to this section and meet all applicable requirements of this article for all facilities included in the consolidated account.

(2) An entity qualified to register cannot apply for more than one registration in the tracking system.

(3) An entity cannot hold a compliance instrument until the Executive Officer approves the entity's registration with ARB and an account in the tracking system.

(4) An entity seeking to list an offset project situated on the categories of land in section 95973(d) must demonstrate the existence of a limited waiver of sovereign immunity entered into pursuant to section 95975(l) prior to registering pursuant to this section.

(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:

(A) Name, physical and mailing addresses, and contact information, type of organization, date and place of incorporation;

(B) Names and addresses of the entity's directors and officers;

(C) Names and contact information for persons controlling over 10 percent of the voting rights attached to all the outstanding voting securities of the entity;

(D) A business number, if one has been assigned to the entity by a California state agency;

(E) A U.S. Federal Tax Employer Identification Number, if assigned;

(F) Data Universal Numbering System number, if assigned;

(G) Statement of basis for qualifying for registration pursuant to sections 95811, 95813, or 95814; and

(H) 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, and a brief description of the association. 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.

(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.

(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.

(2) Applicants may be denied registration in the tracking system: 1. Based on information provided; or 2. If the Executive Officer determines the applicant has provided false or misleading information; or 3. If the Executive Officer determines the applicant has withheld information material to its application.

(3) Any individual listed by the registering entity in its registration application in a capacity requiring access to the tracking system must comply with the Know-Your-Customer requirements pursuant to section 95834 before access to the tracking system will be granted.

(4) An entity must designate a primary account representative, at least one and up to four alternate account representatives pursuant to section 95832. An individual registering as a voluntarily associated entity may elect to serve as

both primary and alternate account representatives or designate additional persons.

(5) An individual registering as a voluntarily associated entity and having a primary residence in the United States, but not located in California, must designate an agent for service of process in California. The agent may be an individual who resides in California, or a corporation, that has previously filed a certificate pursuant to California Corporations Code section 1505.

(6) An entity applying for registration that is not an individual or an entity supplying exchange clearing services pursuant to section 95814(a)(1)(C) must designate, pursuant to section 95832, either:

(A) A primary account representative or at least one alternate account representative with a primary residence in California; or

(B) An agent for service of process in California. For entities registering into California, the agent may be an individual who resides in California, or a corporation, that has previously filed a certificate pursuant to California Corporations Code section 1505.

(7) Any individual who 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.

(A) An individual qualified to register as a user in the tracking system cannot apply for more than one user registration.

(B) An individual cannot be designated in a capacity requiring access to the tracking system until the Executive Officer approves the user's registration in the tracking system. This prohibition includes all primary account representatives, alternate account representatives, and account viewing agents.

(C) An individual registering in the tracking system must provide all applicable information required by sections 95832, 95833, and 95834.

(D) An individual registering in the tracking system must agree to the terms and conditions contained in Appendix B of this article.

(8) An individual may be denied registration:

(A) Based on the information provided;

(B) If the Executive Officer determines the individual has provided false or misleading information;

(C) If the Executive Officer determines the individual has withheld information material to his/her registration;

(D) If an individual fails to comply with section 95834 Know-Your-Customer Requirements; or

(E) If the individual is already registered and has a user account under the same or a different name. This provision applies to individuals registered in an approved external linked GHG emissions trading system.

(d) Registration Deadlines.

(1) An entity that meets or exceeds the inclusion thresholds in section 95812 or an opt-in covered entity must register with the accounts administrator pursuant to this section:

(A) Within 30 calendar days of the reporting deadline contained in MRR if the entity is not a covered entity as of January 1, 2013; or

(B) By January 31, 2012 or within 30 calendar days of the effective date of this regulation, whichever is later, for an entity that exceeds the inclusion thresholds in section 95812 for any data year 2009~~8~~ through 2012~~1~~.

~~(2) An opt-in covered entity must register with the accounts administrator by November 30 of the calendar year prior to the first year in which it voluntarily elects to be subject to a compliance obligation pursuant to section 95813.~~

(~~3~~2) Any voluntarily associated entity that intends to hold an ARB-issued compliance instrument must register with the accounts administrator prior to acquiring such compliance instruments.

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(f) Updating Registration Information.

(1) Registrants 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 10 working days of the change. ~~Registrants must update their registration information within 10 working days of changes to the information listed in section 95830(c).~~

(2) Information may be directly entered into the tracking system operated by the accounts administrator or, if that is not available, submitted to the accounts administrator by the entity.

(3) Registration may be revoked, suspended, or restricted if an entity does not update its registration within 10 days of a change pursuant to section 95921(g)(3).

(g) Information Confidentiality. The following information collected about individuals during the registration process will be treated as confidential by the Executive Officer and the accounts administrator to the extent possible, and except as needed in the course of oversight, investigation, enforcement and prosecution:

(1) Information collected pursuant to section 95830(c)(1)(B),(C),(I) and (~~C~~J);

(2) Information collected about individuals pursuant to section 95834; and

(3) Information collected about individuals pursuant to section 95832.

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(i) Change of ownership. When the ownership of a facility changes, the following information must be submitted to ARB within 30 days of finalization of ownership change:

(1) A description of the acquisition and the effective date of the change of ownership including if the acquisition is the purchase of a facility or facilities from another entity or the purchase of an entity that owns a facility or facilities;

(2) Both the legal and operating names and the tracking system entity IDs of the entities owning the facility or facilities prior to the change of ownership;

(3) Both the legal and operating names and the tracking system entity ID of the purchasing entity, if any;

(4) Written direction whether the purchased facility or facilities will be added to a consolidated entity account or whether the purchased facility or facilities will be associated with an entity that will opt-out of account consolidation pursuant to section 95833(f);

(5) Original signatures by a Director or Officer from the entities being purchased and the purchasing entity, notifying ARB of the change of ownership.

(6) Any changes or new information pursuant to section 95833.

(7) Written direction regarding the disposition of compliance instruments that must be transferred to the purchasing entity. Compliance instruments can be transferred only to the same account type, i.e., from a Compliance Account to a Compliance Account.

(8) If the change of ownership results in the closure of the tracking system account of the entity owning the facility or facilities prior to the change in ownership, the Executive Officer will close the account within 10 days of the change in ownership. It is the responsibility of the entities participating in the change of ownership to transfer any compliance instruments from tracking system accounts they control prior to closure.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95831. Account Types.

(a) Accounts Created for Registered Entities.

(1) The Executive Officer shall not create more than one holding account, one limited use holding account, one compliance account, or one exchange clearing holding account for each entity registered pursuant to 95830.

(2) Holding Accounts. When the Executive Officer approves a registration for a covered entity, an opt-in covered entity, or a voluntarily associated entity, the accounts administrator will create a holding account for the registrant.

(3) Limited Use Holding Accounts. When an entity qualifies for a direct allocation under section 95890(b) the accounts administrator will create a limited use holding account for the entity that shall be subject to the following restrictions:

(A) The entity may not transfer compliance instruments from other accounts into the limited use holding account; and

(B) The entity may not transfer compliance instruments from the limited use holding account to any account other than the Auction Holding Account.

(4) Compliance Accounts. When the Executive Officer approves a registration for a covered entity or opt-in covered entity, the accounts administrator will create a compliance account for the entity.

(A) A covered entity or opt-in covered entity may transfer compliance instruments to its compliance account at any time.

(B) A compliance instrument transferred into a compliance account may not be removed by the entity.

(C) The Executive Officer may transfer compliance instruments into a compliance account. The Executive Officer may remove compliance instruments to satisfy a compliance obligation, or when closing an account.

(5) Exchange Clearing Holding Accounts. When the Executive Officer approves registration for an entity identified as a voluntarily associated entity pursuant to section 95814(a)(1)(C), then the accounts administrator will create an exchange clearing holding account for the entity.

(A) Entities may transfer compliance instruments to exchange clearing accounts only for the purpose of transferring control of the instruments to the entity performing the clearing function.

(B) The clearing entity may only transfer the compliance instruments in its exchange clearing holding account to the account designated by the entity receiving the allowances under the transaction being cleared.

(6) Limited Exemption Holding Account. When an entity qualifies for a direct allocation under section 95870 the accounts administrator will create a limited exemption holding account for the entity.

(A) Except for allowances to be placed in limited use holding accounts, the Executive Officer will place allowances allocated to an entity on a date prior to the vintage year of the allowances into the entity's Limited Exemption Holding Account.

(B) Entities may not transfer allowances from a Limited Exemption Holding account.

(C) Pursuant to section 95856(h)(2)(D), the Executive Officer may remove allowances from the Limited Exemption Holding Account if needed for compliance with the triennial surrender requirement.

(D) Allowances received by an entity through allocations pursuant to section 95870(d) will be transferred on January 1 of the vintage year of the allowances to the compliance accounts designated in the determination made by the entity pursuant to 95892(b)(2)(A).

(E) Allowances received by an entity through allocations pursuant to section 95870(h) will be transferred on January 1 of the vintage year of the allowances to the entity's compliance account pursuant to 95893(b)(1)(B).

(F) Allowances received through allocations pursuant to section 95870(e), (f), and (g) will be transferred to the entity's holding account on January 1 of the vintage year of the allowances.

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(c) Account Closure.

(1) A registered entity's accounts will be closed after the Executive Officer receives a report that an entity has ceased operation pursuant to MRR section 95101(h).

(2) A voluntarily associated entity's accounts may be closed if no compliance instruments are transferred into or out of the accounts for a period of three years.

(3) Compliance instruments needed to fulfill the entity's compliance obligation will be drawn first from the entity's Compliance Account and then from the entity's Holding Account if the Compliance Account does not contain sufficient compliance instruments to meet the compliance obligation.

(34) Compliance instruments remaining in accounts closed by the Executive Officer and not needed to fulfill a compliance obligation will be consigned to auction pursuant to section 95910(d) on behalf of the registered entity.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95832. Designation of Representatives and Agents.

(a) An application for registration into the California Cap-and-Trade Program for an account must designate a single primary account representative and at least one but no more than four alternate account representatives. Any communication between the accounts administrator and an alternate account representative must also be addressed to the primary account representative. A complete application for an account shall be submitted to the accounts administrator and shall include the following elements:

(1) Name, business and primary residence addresses, email addresses, and phone numbers, of the primary account representative and any alternate account representatives and account viewing agents;

(2) Name of the organization designating the primary account representative or any alternate account representative to represent its ownership interest with respect to the compliance instruments held in the account;

(3) The primary account representative and any alternate account representative must attest, in writing, to ARB as follows: "I certify under penalty of perjury under the laws of the State of California that I was selected as the primary account representative or the alternate account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to compliance instruments held in the account. I certify that I have all the necessary authority to carry out the duties and responsibilities contained in title 17, article 5, sections 95800 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the accounts administrator or a court regarding the account";

(4) An attestation verifying the selection of the primary account representative, alternate account representatives, and account viewing agents, signed by the officer of the entity who is responsible for the conduct of the primary account representative, alternate account representatives, and account viewing agents, and is one of the officers disclosed pursuant to section 95830(c)(1)(B);

(5) The signature of the primary account representative and any alternate account representative and the dates signed; and

(6) An attestation as follows: "I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. I ~~also~~ certify under penalty of perjury of the laws of the State of California that ~~all information required to be~~ the statement of information submitted to ARB is true, accurate, and complete."

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95833. Disclosure of Corporate Associations.

(a) Criteria for Determining Corporate Associations.

(1) An entity has a corporate association with another entity, regardless of whether the second entity is subject to the requirements of this article, if either one of these entities:

(A) Holds more than 20 percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;

(B) Holds or can appoint more than 20 percent of common directors of the other entity;

(C) Holds more than 20 percent of the voting power of the other entity;

(D) In the case of a partnership other than a limited partnership, holds more than 20 percent of the interests of the partnership; ~~or~~

(E) In the case of a limited partnership, controls the general partner~~.~~; or

(F) In the case of a limited liability corporation, owns more than 20 percent of the other entity regardless of how the interest is held.

(2) An entity has a "direct corporate association" with another entity, regardless of whether the second entity is subject to the requirements of this article, if either one of these entities:

(A) Holds more than 50 percent of any class of listed shares, the right to acquire such shares, or any option to purchase such shares of the other entity;

(B) Holds or can appoint more than 50 percent of common directors of the other entity;

(C) Holds more than 50 percent of the voting power of the other entity;

(D) In the case of a partnership other than a limited partnership, holds more than 50 percent of the interests of the partnership; ~~or~~

(E) In the case of a limited partnership, controls the general partner~~.~~; or

(F) In the case of a limited liability corporation, owns more than 50 percent of the other entity regardless of how the interest is held.

(3) An entity has a "direct corporate association" with a second entity, regardless of whether the second 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.

(A) An entity (A) has a "direct corporate association" with another entity (B) if the two entities share a common parent that is not registered into the California Cap-and-Trade Program and that parent has a direct corporate association with each entity (A and B) when applying the indicia of control contained in section 95833(a)(2).

(B) An entity with a "direct corporate association" with a second registered entity has a direct corporate association with any registered entity with whom the second registered entity has a direct corporate association.

(4) An entity has an "indirect corporate association" with another entity if:

(A) The two entities do not have a direct corporate association;

(B) The two entities are connected through a line of more than one corporate association; and

(C) The controlling entity's percentage of ownership or other indicia of control under section 95833(a)(1)(A), (B), (C), ~~or~~ (D), or (F) of the indirectly controlled entity is more than 20 percent but less than or equal to 50 percent after multiplying the percentages at each link in the chain of corporate associations.

(5) A publicly-owned electric utility or joint powers agency that is the operator of an electricity generating facility in California has a direct corporate association with the operator of another electricity generating facility in California if the same entity operates both generating facilities. A publicly-owned electric utility or joint powers agency that is the operator of an electricity generating facility in California has a direct corporate association with an electricity importer if the same entity operates the generating facility in California and is the entity importing electricity.

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(f) Consolidation of Accounts for Corporate Associations.

(1) By January 1, 2013, the Executive Officer will consolidate the accounts held by entities registered into the California Cap-and-Trade Program pursuant to section 95830 that are part of a direct corporate association into a consolidated set of accounts.

(2) By October 1, 2012, the primary account representative or alternate account representative for all entities that are part of a direct corporate association and intend to have their accounts consolidated must provide to the Executive Officer:

(A) Confirmation of the corporate association if not already provided;

(B) Confirmation of the entity's intent to have its account consolidated with that of the other entities within the corporate association; and

(C) A change of primary account representative and alternate account representative to new representatives that will serve as the primary account representative and alternate account representatives for the consolidated accounts.

(3) To opt out of consolidation of accounts, the primary account representative or alternate account representative for an entity within the corporate association must provide to the Executive Officer ~~by October 1, 2012~~:

(A) Confirmation of the corporate association if not already provided;

(B) An attestation, signed by the officer of the entity who is responsible for the conduct of the account viewing agent and is one of the officers disclosed pursuant to section 95830(c)(1)(B), that the entity seeks exclusion of its account from the consolidated set of accounts to be created; and

(C) Confirmation of the opt-out decision by the primary account representative or alternate account representative for any entity opting out of consolidation, as well as the primary account representative or alternate account representative designated for any entities remaining in the corporate association consolidated account pursuant to section

95833(f)(2)(C). ~~This confirmation will include a distribution of the purchase and holding limits between the consolidated corporate association and any associated entites opting out of consolidation.~~

1. This confirmation must include an allocation of shares of the holding limit between the consolidated corporate association and any associated entities opting out of consolidation.
2. This confirmation must include an allocation of shares of the purchase limit between the consolidated corporate association and any associated entities opting out of consolidation.

(4) If an entity registered in the California Cap-and-Trade Program has a direct corporate association with an entity(ies) registered in an External Greenhouse Gas Emissions Trading System to which California has linked its Cap-and-Trade Program pursuant to subarticle 12, the entity registered in the California Cap-and-Trade Program must opt out of consolidation with the entity(ies) registered in an External Greenhouse Gas Emissions Trading System and meet all the requirements of section 95833(f)(3). ~~except for the October 1, 2012 deadline.~~

(5) To consolidate the accounts for a corporate association the Executive Officer shall instruct the accounts administrator to:

(A) Create a single consolidated set of accounts for members of a corporate association that accept consolidation;

(B) Include a compliance account only for a corporate association with at least one member entity that accepts consolidation that is eligible for a compliance account;

(C) Include a limited use holding account only for a corporate association with at least one member entity that accepts consolidation that is eligible for a limited use holding account;

(D) Complete all valid transfer requests in the system involving any accounts for the members of the corporate association;

(E) Transfer all compliance instruments in the existing accounts held by the member entities to the appropriate corporate association accounts; and

(F) Close the accounts held by the individual member entities of the corporate association that have not opted out.

(6) Entities with a direct corporate association may change their decision to consolidate accounts or opt-out of consolidation only once each year.

(7) 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.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95834. Know-Your Customer Requirements.

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(c) Verification of information.

(1) Any copy of a document submitted pursuant to section 95834 must be notarized by a notary public no more than three months before submittal.

(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 95834(b).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 6: California Greenhouse Gas Allowance Budgets

§ 95841.1 Voluntary Renewable Electricity.

(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. RECs, if created, must be retired within the year for which VRE retirements are requested.

(b) Reporting Requirements. The end-user, or the VRE participant acting on behalf of the end-user, requesting allowance retirement for eligible generation must meet the following requirements for the period in which allowance retirement is being requested:

(1) By July 1 of each year, provide a written request for allowance retirement for the previous year's generation or REC purchases. Request must meet the requirements below:

(A) Report to ARB the quantity of renewable electricity in MWhs delivered to the California grid, and/or the number of RECs generated during the previous year from an eligible renewable electricity generator that meets the requirements of 95841.1(b)(2) or (3), as applicable;

(B) Generator of the renewable electricity or RECs must be certified as RPS eligible by the California Energy Commission, or must meet design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs, ~~third~~ fifth edition, June 201~~0~~3;

(C) For end-users, or the VRE participants acting on behalf of the end-user choosing to meet (B) above by meeting the California Energy Commission's design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs, ~~third~~ fifth edition, ~~June~~ January, 201~~0~~3, must submit an approval of incentive claim;

(D) Contract, tracking system data, or settlement data for the purchase of the electricity or RECs associated with the generation of the electricity must be submitted;

(E) Contract, tracking system data, or settlement data for sale of the electricity or RECs associated with the generation of the electricity to the end-user or entity purchasing on behalf of the end-user; and

(F) Submit the following attestations:

1. Attest, in writing, to ARB as follows: "I certify under penalty of perjury of the laws of the State of California that I have not authorized use of, or sold, any renewable electricity credits or any claims to the emissions, or lack of emissions, for electricity for which I am seeking ARB allowance retirement, in any other voluntary or mandatory program."

2. Attest, in writing, to ARB as follows: "I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, Cal. Code of Regs. article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this voluntary renewable electricity program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes."

(2) VRE Participants seeking allowance retirement for renewable electricity generation from an eligible facility > 200 KW nameplate capacity must submit the following with the report required in this section, for which the VRE participant is seeking allowance retirement:

(A) Provide the generator's RPS certification identification number, as determined by the California Energy Commission, or proof that each facility or system has met design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs, ~~third~~ fifth edition, ~~June~~anuary~~-~~ 201~~0~~3;

(B) MWhs of renewable electricity generated designated for VRE retirement;

(C) Number of RECs designated for VRE retirement, as applicable; and

(D) WREGIS REC Rretirement Compliance Rreport ~~or tracking system data~~.

(3) VRE participants seeking allowance retirement for renewable electricity generating from an eligible facility ≤ 200 KW nameplate capacity must submit the following with the report required in this section. Applicants may aggregate eligible systems, but must submit one application under one entity:

(A) Provide the generator's RPS certification identification number, as determined by the California Energy Commission, or must meet design and installation standards pursuant to the California Energy Commission's Guidelines for California's Solar Electric Incentive Programs, ~~third~~ fifth edition, ~~June~~anuary 201~~03~~;

(B) MWhs of renewable electricity generated;

(C) Number of RECs, as applicable; and

(D) WREGIS REC ~~r~~Retirement Compliance Rreport ~~or tracking system data, as applicable~~.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 7: Compliance Requirements for Covered Entities

§ 95851. Phase-in of Compliance Obligation for Covered Entities.

(a) Operators of facilities and first deliverers of electricity specified in sections 95811(a) and (b) and carbon dioxide suppliers specified in section 95811(h)~~(g)~~ that meet or exceed the annual emissions threshold in section 95812(c) have compliance obligations beginning with the first compliance period.

(b) Suppliers of natural gas, suppliers of RBOB and distillate fuel oils, ~~and~~ suppliers of liquefied petroleum gas, and suppliers of liquefied natural gas specified in sections 95811(c), (d), (e), (f), and ~~(f)~~(g) that meet or exceed the annual

threshold in section 95812(d) will have a compliance obligation beginning with the second compliance period.

(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) will have a compliance obligation beginning with the second compliance period.

(d) Operators of eligible Waste-to-Energy Facilities, pursuant to section 95852(k) that meet or exceed the annual threshold in section 95812(d) will have a compliance obligation beginning with the second compliance period.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852. Emission Categories Used to Calculate Compliance Obligations.

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(b) First Deliverers of Electricity. A first deliverer of electricity covered under sections 95811(b) and 95812(c)(2) has a compliance obligation for every metric ton of CO_2e emissions calculated pursuant to section 95852(b)(1) for which a positive or qualified positive emissions data verification statement is issued pursuant to MRR, or for which there are assigned emissions, when such emissions are from a source in California or in a jurisdiction where a GHG emissions trading system has not been approved for linkage by the Board pursuant to subarticle 12.

(1) Calculation of emissions for compliance obligation.

(A) For first deliverers that are operators of an electricity generating facility in California, the calculation for compliance obligation includes all emissions reported and verified or assigned pursuant to MRR, except emissions without a compliance obligation pursuant to section 95852.2.

(B) For first deliverers that are electricity importers, emissions with a compliance obligation are calculated using the following equation:

$$CO_2e_{covered} = CO_2e_{unspecified} + (CO_2e_{specified} - CO_2e_{specified\text{-}not\,covered}) - CO_2e_{RPS_adjustment} - CO_2e_{QE_adjustment} - CO_2e_{linked}$$

Where:

$CO_2e_{covered}$ = Annual metric tons of CO_2e with a compliance obligation.

$CO_2e_{unspecified}$ = Annual metric tons of CO_2e from unspecified imported electricity calculated pursuant to MRR 95111.

$CO_2e_{specified}$ = Annual metric tons of CO_2e from imported electricity from specified sources that meet the requirements of MRR section 95111.

$CO_2e_{specified\text{-}not\,covered}$ = Annual metric tons of CO_2e without a compliance obligation pursuant to section 95852.2.from specified sources that meet the requirements in MRR section 95111,

$CO_2e_{RPS_adjustment}$ = Annual metric tons of CO_2e calculated pursuant to MRR that meets the requirements of section 95852(b)(4).

$CO_2e_{QE_adjustment}$ = Annual metric tons of CO_2e from qualified exports pursuant to MRR section 95111 that meet the requirements of section 95852(b)(5).

CO_2e_{linked} = Annual metric tons of CO_2e from electricity with a first point of receipt located in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12.

(C) All deliveries of electricity not meeting the requirements for specified sources pursuant to MRR will have emissions calculated using the default emission factor for unspecified electricity pursuant to section MRR 95111(b)(1).

(2) Resource shuffling is prohibited and is a violation of this article. ~~First Deliverers must submit the following attestations annually to ARB, by June 1, in writing, by certified mail only:~~

~~(A) "I certify under penalty of perjury of the laws of the State of California that [facility or company name] for which I am an agent has not~~

~~engaged in the activity of resource shuffling to reduce compliance obligation for emissions, based on emission reductions that have not occurred as reported under MRR."~~

~~(B) "I understand [facility or company name], for which I am an agent, is participating in the Cap-and-Trade Program under title 17, California Code of Regulations, article 5, and by doing so, it now subjects itself to all regulatory requirements and enforcement mechanisms of this program and subjects itself to the jurisdiction of California as the exclusive venue to resolve disputes."~~

(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.

(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 public utilities code section 8340 et. seq.

(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.

(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.

(5) Electricity deliveries that substitute for power previously supplied by a specified source that has been retired.

(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 GHG compliance obligation.

(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.

(8) Electricity deliveries that are necessitated by expiration of a contract.

(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.

(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.

(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.

(12) Electricity deliveries that are necessitated because a First Deliverer has more than enough electricity to meet demand as a result of the First Deliverer being required to take electricity from specific generating units, including requirements due to electricity contracts with "must-take" or "must-run" provisions.

(13) Deliveries of electricity that are required to make up for transmission losses associated with electricity deliveries in California.

(B) Prohibited substitutions of electricity deliveries from a higher emission resource with electricity deliveries from a lower emission resource include:

(1) 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 EPS, and the substitution is made to reduce a First Deliverer's compliance obligation.

(2) Assigning a long-term contract for high emission electricity specified in section 95852(b)(2)(B)(1) directly above to a third party, for the purpose of reducing a compliance obligation.

(3) The following criteria must be met for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emission factor or asset controlling supplier emission factor. ~~less than the default emission factor.~~

(A) Electricity deliveries must be reported to ARB and emissions must be calculated pursuant to MRR section 95111.

(B) The electricity importer must be the facility operator or have right of ownership or a written power contract, as defined in MRR section 95102(a), to the amount of electricity claimed and generated by the facility or unit claimed;

(C) The electricity must be directly delivered, as defined in MRR section 95102(a), to the California grid; and

(D) If RECs were created for the electricity generated and reported pursuant to MRR, then the RECs serial numbers must be ~~retired~~ reported and verified pursuant to MRR.

(4) RPS adjustment. 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. Ownership or contract rights to procure the electricity and the associated RECs generated by the eligible renewable energy resource; or
2. ~~Have a~~ A contract to procure electricity 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 generated by the eligible renewable energy resource, as verified ~~under~~ 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 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 ~~used to comply with California RPS requirements~~ during the same year ~~in~~ for which the RPS adjustment is claimed.

(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 reported electricity generated (MWh) 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.

(E) No RPS adjustment may be claimed for electricity generated by an eligible renewable energy resource in a jurisdiction where a GHG emissions trading system has been approved for linkage by the Board pursuant to subarticle 12.

(F) Only RECs representing electricity generated after 12/31/2012 are eligible to be used towards the RPS adjustment.

(5) QE adjustment. An adjustment to the compliance obligation pursuant to the calculation in 95852(b)(1) may be made for exported and imported electricity during the same hour by the same PSE. Emissions included in the QE adjustment for qualified exports claimed by a first deliverer must meet the following requirements:

(A) During any hour in which an electricity importer claims qualified exports and corresponding imports, the maximum amount of QE adjustment for the hour shall not exceed the product of:

1. The lower of either the quantity of exports or imports (MWh) for the hour; multiplied by
2. The lowest emission factor of any portion of the qualified exports or corresponding imports for the hour.

(B) Emissions and MWhs included in the QE adjustment must be reported and verified or assigned pursuant to MRR, and must be documented by hourly import and export data pursuant to MRR.

(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 CO_2e 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:

(1) Suppliers of natural gas shall report the total metric tons CO_2e of GHG emissions delivered to all end users in California pursuant to section 95122 of MRR;

(2) ARB shall calculate the metric tons CO_2e of GHG emissions for natural gas delivered to covered entities 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 reports 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 provisions described in section 95131(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; and

(4) The Executive Officer shall calculate the metric tons CO_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 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.

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(e) Suppliers of Liquefied Petroleum Gas~~Natural Gas Liquids~~:

(1) A producer of liquefied petroleum gas covered under sections 95811(e) and 95812(d) has a compliance obligation for every metric ton CO_2e of 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 all fuel sold, distributed, or otherwise transferred for consumption in California; and

(2) An importer consignee, as defined under MRR, of liquefied petroleum gas covered under section 95811(e) has a compliance obligation for every metric ton CO_2e of 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 all fuel imported into California.

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(g) Carbon Dioxide Suppliers. An entity that supplies carbon dioxide, "Carbon Dioxide Supplier" or CO_2 Supplier", ~~(defined in section 95802(a)(47)~~ covered under sections 95811(h)~~(g)~~ and 95812(c)(3) has an aggregated compliance obligation based on the sum of MT CO_2 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 ~~and which are defined in sections 95802(a)(47)(a), 95802(a)(47)(b), and 95802(a)(47)(c),~~ minus exported CO_2 that is not geologically sequestered, minus imported CO_2, and minus CO_2 verified to be geologically sequestered through use of a Board-approved carbon capture and geologic sequestration quantification methodology that ensures that the emissions reductions are real, permanent, quantifiable, verifiable, and enforceable. Emissions of CO2 already covered with a compliance obligation upstream are not included.

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(i) The compliance obligation for sources specified in sections 95852(a) through (h), and 95852(l) is calculated based on the sum of the following, as applicable:

(1) Emissions of CO_2, CH_4, and N_2O which resulted from combustion of fossil fuel;

(2) Emissions of CH_4 and N_2O which resulted from combustion of all biomass-derived fuel;

(3) Emissions of CO_2 which resulted from combustion of biomass-derived fuels that do not meet the requirements in section 95852.2(a);

(4) Emissions of CO_2 which resulted from combustion of biomass-derived fuels pursuant to section 95852.1; and

(5) All process and vented emissions of CO_2, CH_4, and N_2O as specified in the MRR except for those listed in section 95852.2(b).

(j) Limited Exemption of Emissions from the Production of Qualified Thermal Output During the First Compliance Period. During the first compliance period, emissions from the production of qualified thermal output from a district heating facility or a facility with a cogeneration unit that meets the requirements of this section and has been approved by the Executive Officer for an emissions exemption shall not have a compliance obligation and shall not count toward the inclusion threshold of section 95812(c)(1).

(1) A facility with a cogeneration unit may apply for the emissions exemption for the first compliance period if it meets the following two conditions for each year from 2008-2013, based on data reported pursuant to MRR:

(A) The facility's annual emissions associated with the production of qualified thermal output, calculated using the following equation, are less than 25,000 metric tons of CO_2e:

$$GHG_{QTO} = Q_{produced} * 0.06244$$

Where:

"GHG_{QTO}" is the annual emissions for each calendar year, in metric tons of CO_2e, associated with the production of qualified thermal output;

$Q_{produced}$ is the annual amount of qualified thermal output produced for each calendar year, measured in MMBtu, at the cogeneration facility; and,

(B) The facility's remaining emissions, calculated pursuant to the following equation, are less than 25,000 metric tons of CO2e:

$$GHG_R = GHG_{Total} - GHG_{QTO}$$

Where:

"GHG_R" is the annual remaining emissions, in metric tons of CO_2e.

"GHG_{Total}" is total annual emissions, in metric tons of CO_2e.

(2) A district heating facility may apply for the emissions exemption for the first compliance period if the annual emissions associated with qualified thermal output distributed to each single facility on its system do not exceed 25,000 $MTCO_2e$:

(A) Emissions associated with a single facility are calculated using the following equation:

$$GHG_{sf} = Q_{sf} * 0.06244$$

Where:

"GHG_{sf}" is the emissions associated with a single facility.

"Q_{sf}" is the amount of Qualified Thermal Output provided to a single facility, measured in MMBtu.

(3) Data Sources. The Executive Officer may employ all available data reported to ARB under MRR for data years 2008-2013 to determine a facility's eligibility for the limited exemption of emissions from the production of qualified thermal output.

(4) A facility with a cogeneration unit or a district heating facility must apply to the Executive Officer for the emissions exemption for the first compliance period by providing the following data by September 15 2014:

(A) Annual qualified thermal output for each year from 2008 to 2013, in MMBtu.

(B) A district heating facility must provide the amount of qualified thermal output provided to each single facility it serves.

(C) The application must include the following attestation:
" I certify under penalty of perjury of the laws of the State of California that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity], and that the information submitted herein is true, accurate, and complete."

(D) Operators of facilities that meet the requirements of this section must register in the tracking system pursuant to section 95830.

(E) Operators of facilities that meet the requirements of this section must report and verify emissions pursuant to MRR.

(k) Limited Exemption of Emissions for Waste-to-Energy Facilities During the First Compliance Period. Emissions reported and verified in the first compliance period for the direct combustion of municipal solid waste in a waste-to-energy facility that had started operation before 2009 that meets the requirements of this section do not have a compliance obligation and shall not count toward the inclusion threshold of section 95812(c)(1). The exempted waste-to-energy facility must meet the following criteria:

(1) Operators of Waste-to-Energy Facilities must register in the tracking system pursuant to section 95830;

(2) Report and verify emissions pursuant to MRR;

(3) The generated electricity must be provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid;

(4) Must be operating under a current permit issued by the local Air Pollution Control District or Air Quality Management District; and

(5) Fuel must be derived from municipal solid waste, as defined in the section 95802 of this article and MRR.

(6) The Executive Officer will place the number of 2015 true-up allowances equal to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years into their compliance account. The Executive Officer will retire the allowances placed into the account according to the surrender date in section 95856, Timely Surrender of Compliance Instruments by a Covered Entity.

(l) Suppliers of Liquefied Natural Gas. A supplier of liquefied natural gas covered under sections 95811(g) or 95812(d) has a compliance obligation for every metric ton CO_2e of 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.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.1.1. Eligibility Requirements for Biomass-Derived Fuels.

(a) Biomass-derived fuel procured under contracts for biogas and biomethane must meet one of the following criteria. Only the portion of the fuel that meets one of these criteria will be considered a biomass-derived fuel. Emissions from combustion of this fuel will not be subject to a compliance obligation when reported as Biomass CO_2 in an emissions data report that has received a positive or qualified positive emissions data verification statement and determined as exempt pursuant to section 95852.2 and 95103(g) of MRR.

(1) The contract for purchasing any biomass-derived fuel must be executed prior to January 1, 2012 and remain in effect or have been renegotiated with the same California operator within one year of contract expiration. The delivery of the fuel under the contract must commence by one of the following dates to be eligible under this provision:

(A) 90 days after the execution date of the signed contract; or

(B) January 1, 2012; or

(C) 10 days after the date on which the CEC provides notice that the operator's electricity generating facility is certified as eligible for California's Renewables Portfolio Standard for the contracted biomass-derived fuel, or cannot be so certified, provided that the application for certification was submitted to the CEC before January 1, 2012.

(2) ~~The fuel being provided under a contract dated on or after January 1, 2012 must only be for an amount of fuel that is associated with~~ If the biomass-derived fuel does not meet the requirements of 95852.1.1(a)(1) then the biomass-derived fuel must meet one of the following requirements and the entity claiming the biomass-derived fuel must be the first entity to contract for the biomass-derived fuel:

(A) An increase in the biomass derived fuel production capacity, at a particular site, where an increase is considered any amount over the average production at that site over the last three years; or

(B) Recovery of the fuel at a site where the fuel was previously being vented or destroyed for at least three years or since commencement of

fuel recovery operations, whichever is shorter, without producing useful energy transfer.

~~(3) The fuel being provided under a contract is for a fuel that was previously eligible under sections 95852.1.1(a)(1) or (2), and the verifier is able to track the fuel to the previously eligible contract; or~~

~~(4)~~(3) If the biogas or biomethane is used at the site of production, and not transferred to another operator, thus not requiring a contract, the operator must demonstrate one of the following:

(A) The fuel has been combusted in California prior to January 1, 2012; or

(B) The fuel was not previously used to produce useful energy transfer for at least three years or since commencement of fuel recovery operations, whichever is shorter.

(4) The fuel being provided under a contract is for a fuel that was previously eligible under sections 95852.1.1(a)(1),(2) or (3), and the verifier is able to track the fuel to the previously eligible contract.

(b) An entity may not sell, trade, give away, claim, or otherwise dispose of any of the carbon credits, carbon benefits, carbon emissions reductions, carbon offsets or allowances, howsoever entitled, attributed to the fuel production that would, when combined with the CO_2 emissions from complete combustion of the fuel, result in more CO_2e emissions than would have occurred in the absence of the fuel production. In the case of biomethane or biogas produced from digesters or landfills, the resulting credit for avoided methane emissions may not exceed ~~23.75~~ the global warming potential as listed in MRR for methane plus 2.75 in metric tons of CO_2e per ton of captured methane. This includes any credit received by an entity in the Carbon Intensity calculation under the Low Carbon Fuel Standard Regulation (title 17, California Code of Regulations (CCR), sections 95480-95490) for methane capture. All calculations of CO_2e emissions are based on the 100-year global warming potentials included in MRR. Generation of Renewable Energy Credits is excluded from this analysis and will not prevent a biomass-derived fuel that meets the requirements in this section from being exempt from a compliance obligation.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95852.2. Emissions without a Compliance Obligation.

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(b) The following additional process, vented, and fugitive emissions:

(1) Emissions from geothermal generating units and geothermal facilities, including geothermal geyser steam or fluids;

(2) Emissions from natural gas hydrogen fuel cells;

(3) Vented and fugitive emissions from storage tanks used in petroleum and natural gas production and natural gas transmission;

(4) Vented and fugitive emissions reported under section 95153 of MRR by local distribution companies that report under section 95122 of MRR;

(5) Vented and fugitive emissions from natural gas transmission storage tanks used in petroleum and natural gas production and natural gas transmission, and from produced water;

(6) Emissions reported by petroleum refineries from asphalt blowing operations, equipment leaks, storage tanks, and loading operations;

(7) Emissions from low bleed pneumatic devices;

(8) Emissions from high bleed pneumatic devices reported prior to January 1, 2015;

(9) Vented emissions from well-site centrifugal and reciprocating compressors with a rated horsepower less than 250hp;

(10) Sources for which fugitive emissions are estimated using leak detection and leaker emission factors, as required by section 95153(~~q~~o) of MRR, and sources for which vented and fugitive emissions are estimated using a population count and emissions factors, as required by section 95153(p) of MRR; ~~and~~

(11) Sources for which emissions originate from offshore petroleum and natural gas production facilities, as provided in section 95153(q) of MRR;

(1~~4~~2) Carbon dioxide that is imported, or that is exported for purposes other than geologic sequestration or enhanced oil recovery~~.~~ ; and

(13) Carbon dioxide used in the carbonation process during sugar production in facilities with NAICS code 311313.

(c) ~~Additional~~ Other Exemptions. The operators of facilities with any of the following activities ~~NAICS code 92811~~ are exempt from compliance with this article ~~through December 31, 2013.~~:

(1) NAICS Code 92811.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95853. Calculation of Covered Entity's Triennial Compliance Obligation.

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~~(e) For a new entrant that is eligible to receive free allowances pursuant to subarticles 8 and 9, the first year for this entity to receive free allowances is the year following the first year in which its emissions exceed the threshold in section 95812. The number of free allowances for this new entrant to receive in that year is twice the number calculated pursuant to section 95891.~~

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95856. Timely Surrender of Compliance Instruments by a Covered Entity.

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(b) Compliance Instruments Valid for Surrender.

(1) A compliance instrument listed in subarticle 4 may be used to satisfy a compliance obligation.

(2) To fulfill a compliance obligation, a compliance instrument issued pursuant to sections 95820(a) and 95821(a) must be issued from an allowance budget year within or before the year for which an annual compliance obligation is

calculated or the last year of a compliance period for which a triennial compliance obligation is calculated, unless:

(A) The allowance was purchased from ~~the~~an Allowance Price Containment Reserve sale pursuant to section 95913 or compliance instruments pursuant to section 95821(f)(1); ~~or~~

(B) The allowance is used to satisfy an excess emissions obligation; or

(C) The allowance is eligible for compliance use pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D).

(c) A covered entity must transfer from its 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.

(d) Deadline for 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:

(1) By November 1, 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect), of the calendar year following the year for which the obligation is calculated if the entity reports by April 10 pursuant to section 95103 of MRR; or

(2) By November 1, 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect), of the calendar year following the year for which the obligation is calculated if the entity reports by June 1 pursuant to section 95103 of MRR.

(3) In years 2015, 2018, and 2021 there is no annual compliance obligation for the ~~preceeding~~ preceding compliance period, only a triennial compliance obligation.

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(f) Surrender of Triennial Compliance Obligation.

(1) The covered entity must transfer sufficient valid compliance instruments 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.

(2) The total number of compliance instruments submitted to fulfill the triennial compliance obligation is subject to the quantitative use limit pursuant to section 95854.

(3) The surrender of compliance instruments must equal 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~~When the Executive Officer has determined~~ determining whether the covered entity has ~~met~~fulfilled its compliance obligations, the Executive Officer shall:

(1) ~~Retire the compliance instruments surrendered~~In the case of annual compliance obligations, determine the status of compliance with the annual compliance obligation by evaluating the number and types of compliance instruments in the Compliance Account; and

(2) In the case of triennial compliance obligations:

(A) Retire the compliance instruments surrendered; and

(B) Inform programs to which California is linked or recognizes, pursuant to subarticles 12 and 14, of the retirements, including the serial numbers of the compliance instruments retired.

(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), 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 and ensuring there are enough 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 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).

(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 surrender deadline

to meet the timely surrender of compliance instrument requirements in section 95856.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95857. Untimely Surrender of Compliance Instruments by a Covered Entity.

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(b) Calculation of the Untimely Surrender Obligation.

(1) The quantity of excess emissions is the difference between the compliance obligation calculated pursuant to this section and any compliance instruments timely surrendered by the entity;

(2) The entity's compliance obligation for untimely surrender is calculated as four times the entity's excess emissions;

(3) At least three-fourths of an entity's compliance obligation for untimely surrender may only be fulfilled with CA GHG allowances or allowances issued by a GHG ETS pursuant to subarticle 12;

(4) Up to one-fourth of an entity's compliance obligation for untimely surrender may be fulfilled with ARB offset credits or compliance instruments listed in sections 95821(b), (c), (d) and (f)(1)~~(d)~~;

(5) The quantitative usage limit provided in section 95854 will apply to the compliance instruments listed in section 95857(b)(4) for the compliance period for which the untimely surrender obligation applies; and

(6) The untimely surrender obligation is due within five days of the first auction or reserve sale conducted by ARB following the applicable surrender date, whichever is the latter, and for which the registration deadline has not passed when the untimely surrender obligation is assessed.

***

(d) When the covered entity or opt-in covered entity meets its untimely surrender obligations pursuant to sections 95857(a) through (c), the Executive Officer shall:

(1) Transfer the compliance instruments used to fulfill the untimely surrender obligation in the following manner:

(A) At least three fourths of the compliance instruments to the Auction Holding Account. The three fourths of the compliance instruments transferred to the Auction Holding Account shall only be comprised of allowances; and

(B) The remaining one fourth of compliance instruments shall remain in the covered entity or opt-in entity's compliance account until the next triennial surrender date, after which they will be transferred to the Retirement Account.

(2) Inform programs to which California is linked or recognizes, pursuant to subarticles 12 and 14, of the retirements, including the serial numbers of the compliance instruments retired.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 8: Disposition of Allowances

§ 95870. Disposition of Allowances.

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(b) Advance Auction. Upon creation of the Auction Holding Account, the Executive Officer shall transfer 10 percent of the allowances from budget years 2015-2020 to the Auction Holding Account.

(1) These allowances will be eligible to be sold pursuant to section 95913(f)~~shall be auctioned pursuant to section 95910~~.

(2) All Advance Auction allowances not sold pursuant to section 95913(f) will be auctioned pursuant to section 95910.

(~~2~~3) The proceeds from the sale of these allowances will be deposited into the ~~Air Pollution Control Fund~~ Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8, and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety

Code sections 38500 et seq. and consistent with the requirements of Chapter 4.1 (commencing with Section 39710) of Part 2 of Division 26 of the California Health and Safety Code and Article 9.7 (commencing with Section 16428.8) of Chapter 2 of Part 2 of Division 4 of Title 2 of the Government Code.

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(d) Electricity Related Allocation.

(1) Electrical Distribution Utility Sector Allocation. Allowances available for allocation to electrical distribution utilities each budget year shall be 97.7 million metric tons multiplied by the cap adjustment factor in Table 9-2 for each budget year 2013-2020. The Executive Officer will allocate to electrical distribution utilities on September 14, 2012 for vintage 2013 allowances and October 15~~November 1~~, or the first business day thereafter, of each calendar year from 2013-2019 for allocations from 2014-2020 annual allowance budgets.

(2) Allocation to Public Wholesale Water Agencies. The Executive Officer will place an annual individual allocation in the compliance account 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..

(e) Allocation to Industrial Covered Entities. Allowances allocated for the purposes of industry assistance shall be transferred to ~~holding accounts~~ Limited Exemption Holding Accounts for industrial sectors listed in Table 8-1. Allowances in the Limited Exemption Holding Account are transferred to the Holding Account on the first business day of each year once their vintage is equal to the current calendar year.

(1) The Executive Officer will allocate allowances from 2013-2020 annual allowance budgets to ~~place an annual individual allocation in the holding account of~~ each eligible covered entity on or before October 15~~November 1~~, or the first business day thereafter, of each calendar year ~~2012~~2013-2019 for allocations from ~~2013~~2014-2020 annual allowance budgets.

(2) Allocation to eligible covered entities shall be conducted using the assistance factors specified for each listed industrial activity found in Table 8-1 and the methodology set forth in section 95891.

(A) First Compliance Period Refining Sector Allocation. Allowances available for allocation to petroleum refineries from the 2013-2014 allowance budgets shall be calculated using the following equation. Individual petroleum refiners will receive a portion of this sector allocation under the method calculated pursuant to section 95891(d).

$$SA_t = O_{t-2} * B_R * AF_{R,t} * c_t$$

Where:

"SA_t" is the allocation to the refining sector from budget year "t";

"O_{t-2}" is the output of primary refinery products, in barrels, from the refining sector in year "t-2";

"B_R" is the benchmark for primary products produced by the refining sector, equal to 0.0462 metric tons of allowances per barrel of primary refinery product;

"$AF_{R,t}$" is the assistance factor for budget year "t" assigned to petroleum refining as specified in Table 8-1; and

"c_t" is the cap adjustment factor for budget year "t" assigned to petroleum refining to account for cap decline as specified in Table 9-2.

(B) Second and Third Compliance Period Refining Sector Allocation. For budget years 2015-2020, allowances available for allocation to individual petroleum refineries shall be calculated using the product output-based allocation calculation methodology in section 95891(b).

(3) The total amount of allowances allocated for the purposes of industry assistance shall not exceed the available amount of allowances after accounting for allocations made pursuant to section 95870(a) through (d). If the amount calculated under the methodology set forth in section 95891 exceeds the amount of allowances available, the number of allowances available will be prorated equally across all eligible industrial covered entities. The proration will be calculated using the share of allowances available after

accounting for all allocations made pursuant to sections 95870(a) through (d) compared to total allowances that would be distributed according to the methodology set forth in section 95891.

(4) Industrial entities who purchase electricity or qualified thermal output pursuant to a legacy contract and who receive allocation under this section shall have their allocation reduced as specified in section 95891(h).

(5) If a facility approved for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) did not receive any industrial allocation in calendar years 2013 and 2014, the Executive Officer shall place in its compliance account, on October 15, 2014, the amount of allowances equal to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years, less the amount of allowances in its compliance account as of October 14, 2014. The Executive Officer will place in the facility's holding account the amount of allowances equivalent to the allowances in its compliance account as of October 14, 2014. The Executive Officer shall retire the amount of allowances equivalent to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years according to the surrender date in section 95856.

(6) If a facility approved for a limited exemption of emissions from the production of qualified thermal output pursuant to section 95852(j) received an industrial allocation in calendar years 2013 or 2014, it must place allowances equal to the amount received in 2013 and 2014 into its compliance account. If the amount of allowances equal to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years exceeds the amount received in calendar years 2013 and 2014, the Executive Officer will place in the facility's compliance account the difference between the that amount and the amount received in 2013 and 2014. If the allowances received in calendar years 2013 and 2014 exceeds the amount the facility's reported, verified, and covered emissions for the 2013 and 2014 data years, the facility will have its future allocations reduced by the excess allowances received, and allowances shall be subtracted from the facility's budget year 2015 allocation

and from subsequent budget year's industrial allocations each year until the total amount subtracted equals the amount by which the industrial allocation amount received in 2013 and 2014 exceeds the reported, verified, and covered emissions for the 2013 and 2014 data years. The Executive Officer shall retire the amount of allowances equivalent to the facility's reported, verified, and covered emissions for the 2013 and 2014 data years according to the surrender date in section 95856.

(f) Allocation to University Covered Entities and Public Service Facilities. The Executive Officer will place an annual individual allocation from budget year 2015 in the holding account of each eligible university covered entity and public service facility for calendar years 2013, 2014, and 2015 on or before October 15, 2014. The Executive Officer will place an annual individual allocation in the holding account of each eligible university covered entity and public service facility on or before October 15, or the first business day thereafter, of each calendar year from 2015-2019 for allocations from 2016-2020 annual allowance budgets. A public service facility providing steam to a publicly-owned educational facility is not eligible for any allocation of allowances provided under other provisions of this regulation. In the event a publicly-owned educational facility becomes an opt-in covered entity, the publicly-owned educational facility will unconditionally transfer to the public service facility allowances relating to the steam or chilled water provided by such public service facility. So long as the publicly-owned educational facility remains an opt-in covered entity and provides such allowances to the public service facility, such public service facility will not be eligible for any disposition of allowances provided under this section.

(g) Allocation to Legacy Contract Generators. Allowances will be allocated to legacy contract generators for 2013 and 2014 for transition assistance. The Executive Office will transfer allowance allocations into each eligible generator's limited exemption holding account by October 15, 2014 for eligible Legacy Contract Emissions pursuant to the methodology set forth in section 95894.

(h) Natural Gas Supplier Sector Allocation. Allowances available for allocation to natural gas suppliers each budget year shall be calculated as set forth in section

95893. The Executive Officer will allocate to natural gas suppliers on October 15, or the first business day thereafter, of each calendar year from 2014 through 2019 for allocations from 2015 through 2020 annual allowance budgets.

(fi) Auction Proceeds for AB 32 Statutory Objectives.

(1) Beginning in 2015, 10% of all remaining allowances from each vintage not allocated for uses specified in section 95870(a) are eligible to be sold pursuant to section 95913(f).

(42) All remaining allowances not allocated for uses specified in sections 95870(a) through (h)~~(e)~~ will be designated for sale at auction. The proceeds from the sale of these allowances will be deposited into the ~~Air Pollution Control Fund~~ Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8, and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq. and consistent with the requirements of Chapter 4.1 (commencing with Section 39710) of Part 2 of Division 26 of the California Health and Safety Code and Article 9.7 (commencing with Section 16428.8) of Chapter 2 of Part 2 of Division 4 of Title 2 of the Government Code

Table 8-1: Industry Assistance

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (AF_s) by Budget Year		
				2013-2014	2015-2017	2018-2020
High	Crude Petroleum and Natural Gas Extraction	211111	Thermal EOR Crude Oil Extraction	100%	100%	100%
			Non-Thermal Crude Oil Extraction	100%	100%	100%
	Natural Gas Liquid Extraction	211112	Natural Gas Liquid Processing	100%	100%	100%
	All Other Metal Ore Mining	212299	Rare Earth Production	100%	100%	100%
	Potash, Soda, and Borate Mineral Mining	212391	Mining and Manufacturing of Soda Ash and Related Products	100%	100%	100%
	All Other Nonmetallic Mineral Mining	212399	Diatomaceous Earth Mining	100%	100%	100%
	Paper (except Newsprint) Mills	322121	Tissue Manufacturing	100%	100%	100%
	Paperboard Mills	322130	Recycled Boxboard Manufacturing	100%	100%	100%
			Recycled Linerboard (Testliner) Manufacturing	100%	100%	100%
			Recycled Medium (Fluting) Manufacturing	100%	100%	100%
	All Other Petroleum and Coal Products Manufacturing	324199	Coke Calcining	100%	100%	100%
	All Other Basic Inorganic Chemical Manufacturing	325188	All Other Basic Inorganic Chemical Manufacturing	100%	100%	100%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (AF)		
	All Other Basic Organic Chemical Manufacturing	325199	All Other Basic Organic Chemical Manufacturing	100%	100%	100%
	Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production	100%	100%	100%
			Calcium Ammonium Nitrate Solution Production	100%	100%	100%
	Flat Glass Manufacturing	327211	Flat Glass Manufacturing	100%	100%	100%
	Glass Container Manufacturing	327213	Container Glass Manufacturing	100%	100%	100%
	Cement Manufacturing	327310	Cement Manufacturing	100%	100%	100%
	Lime Manufacturing	327410	Dolime Manufacturing	100%	100%	100%
	Mineral Wool Manufacturing	327993	Fiber Glass Manufacturing	100%	100%	100%
	Iron and Steel Mills	331111	Steel Production Using Electric Arc Furnace	100%	100%	100%
	Rolled Steel Shape Manufacturing	331221	Hot Rolled Steel Sheet Production	100%	100%	100%
	All Other Metal Ore Mining	212299	Rare Earth Production	100%	100%	100%
	Mineral Wool Manufacturing	327993	Fiber Glass Manufacturing	100%	100%	100%
Medium	Food Manufacturing	311	Food Manufacturing	100%	10075%	7550%
	Cut and Sew Apparel Manufacturing	3152	Cut and Sew Apparel Manufacturing	100%	10075%	7550%
	Breweries	312120	Brewing	100%	10075%	7550%
	Petroleum Refineries	324110	Petroleum Refining	100%	10075%	7550%
	Asphalt Paving Mixture and Block Manufacturing	324121	Asphalt Paving Mixture and Block Manufacturing	100%	100%	75%
	Industrial Gas Manufacturing	325120	Gaseous Hydrogen Production	100%	10075%	7550%
			Liquefied Hydrogen Production	100%	10075%	7550%
	Ethyl Alcohol Manufacturing	325193	Ethyl Alcohol Manufacturing	100%	100%	75%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (AF)		
	Biological Product (Except Diagnostic) Manufacturing	325414	Biological Product (Except Diagnostic) Manufacturing	100%	10075%	7550%
	Gypsum Product Manufacturing	327420	Plaster Manufacturing	100%	10075%	7550%
			Plaster Board Manufacturing	100%	10075%	7550%
	~~Mineral Wool Manufacturing~~	~~327993~~	~~Fiber Glass Manufacturing~~	~~100%~~	~~75%~~	~~50%~~
	Rolled Steel Shape Manufacturing	331221	Picked Steel Sheet Production	100%	10075%	7550%
			Cold Rolled and Annealed Steel Sheet Production	100%	10075%	7550%
			Galvanized Steel Sheet Production	100%	10075%	7550%
			Tin Steel Plate Production	100%	10075%	7550%
	Secondary Smelting and Alloying of Aluminum	331314	~~Secondary Smelting and Alloying of Aluminum~~ Aluminum Alloy Billet Manufacturing	100%	10075%	7550%
	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (Except Copper and Aluminum)	331492	~~Secondary Smelting, Refining, and Alloying of Nonferrous Metal (Except Copper and Aluminum)~~Lead Acid Battery Recycling	100%	10075%	7550%
	Iron Foundries	331511	Iron Foundries	100%	10075%	7550%
	Hardware Manufacturing	332510	Hardware Manufacturing	100%	100%	75%
	Turbine and Turbine Generator Set Units Manufacturing	333611	Testing of Turbines and Turbine Generator Sets	100%	10075%	7550%
Low	Pharmaceutical and Medicine Manufacturing	325412	Pharmaceutical and Medicine Manufacturing	100%	10050%	5030%
	Nonferrous Forging	332112	Nonferrous Metal Forging	100%	100%	50%
	Aircraft Manufacturing	336411	Aircraft Manufacturing	100%	10050%	5030%
	Support Activities for Air Transportation	4881	Support Activities for Air Transportation	100%	10050%	5030%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (IAF)		
	Guided Missile and Space Vehicle Manufacturing	336414	Guided Missile and Space Vehicle Manufacturing	100%	100%	50%

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code~~.~~ and Section 16428.8, Government Code.

Subarticle 9: Direct Allocations of California GHG Allowances

§ 95890. General Provisions for Direct Allocations.

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(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility that is a covered entity shall be eligible for direct allocation of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.

(c) Electrical Distribution Utilities that are not covered entities but are listed in Table 9-3 must register pursuant to section 95830 to receive allowances.

(d) Eligibility Requirements for University Covered Entities and Public Service Facilities. A University Covered Entity or public service facility shall be eligible for direct allocations of California GHG allowances if it has complied with the requirements of MRR and has obtained a positive or qualified positive verification statement for the prior year pursuant to MRR.

(e) Eligibility Requirements for Legacy Contract Generators. A Legacy Contract Generator that has demonstrated its eligibility to the satisfaction of the Executive Officer pursuant to section 95894 of this regulation shall be eligible for direct allocation of allowances if it has complied with the requirements of the MRR, section 95112 and has obtained a positive or a qualified positive verification statement for pursuant to MRR.

(f) Eligibility Requirements for Natural Gas Suppliers. 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 MRR and has obtained a positive or qualified positive emissions data verification statement for the prior year pursuant to MRR.

(g) Eligibility Requirements for Public Wholesale Water Agencies. A public wholesale water agency shall be eligible for direct allocations of California

GHG allowances if it has complied with the requirements of MRR, and has obtained a positive or qualified positive verification statement for the prior year pursuant to MRR.

(h) No facility receiving allowances pursuant to section 95870(f) may also receive allowances pursuant to section 95870(g).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95891. Allocation for Industry Assistance.

(a) The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the product output-based allocation calculation methodology specified in section 95891(b) if the entity conducts an activity listed in both Table 8-1 and Table 9-1. The Executive Officer shall determine the amount of allowances directly allocated to each eligible covered entity or opt-in covered entity using the energy-based allocation calculation methodology specified in section 95891(c) if the entity conducts an activity listed in Table 8-1 but not listed in Table 9-1.

(1) First Compliance Period Refining Sector Allocation Exception. For budget years 2013-2014 petroleum refineries shall receive their allocation of allowances pursuant to the methodology stated in section 95891(d).

(2) Second and Third Compliance Period Refining Sector Allocation. For ~~buget~~ budget years 2015-2020, petroleum refineries shall receive their allocation of allowances pursuant to the product output-based allocation calculation methodology stated in section 95891(b), using carbon weighted tonne or complexity weighted barrel metrics detailed in the sections 95113(l)(3)-(4) of MRR.

(3) New Entrant Industrial Allocation Without Leakage Risk. Covered facilities that were not covered under the California Cap-and-Trade

Program prior to 2012 and do not have a leakage risk in Table 8-1 are eligible to receive allocated allowances under the new entrant energy-based allocation methodology pursuant to 95891(c)(3) if the first three digits of the facility NAICS code matches a NAICS code in Table 8-1. The leakage risk classification shall be low until a leakage risk classification is added for that sector. Food processors that are only classified by a three digit NAICS code are exempt from this classification.

(b) Product Output-Based Allocation Calculation Methodology. The Executive Officer shall calculate the amount of California GHG Allowances directly allocated under a product output-based methodology annually using the following formula:

~~$$A_t = \sum_{a=1}^{n} O_{a,initial} * B_a * AF_{a,t} * c_{a,t} + \sum_{a=1}^{n} O_{a,trueup} * B_a * AF_{a,t-2} * c_{a,t-2}$$~~

$$A_t = \left(\sum_{a=1}^{n} O_{a,t-2} * B_a * AF_{a,t} * c_{a,t} \right) + TrueUp_t$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities with a product output-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

~~"t-4" is the year four years prior to year "t";~~

"a" is each eligible activity as defined in Table 9-1;

"n" is the number of eligible activities at a facility;

"$O_{a,\ \text{~~initial~~}\ \underline{t\text{-}2}}$" will be calculated by the Executive Officer as the output in year "t-2" as reported to ARB.

~~"$O_{a,trueup}$" adjusts for any output in year "t" not properly accounted for in prior allocations. The Executive Officer will calculate this term using the difference between the output reported in data year "t-2" and the output reported in data year "t-4."~~

"B_a" is the emissions efficiency benchmark per unit of output for each eligible activity defined in Table 9-1;

"$AF_{a,\ t}$" is the assistance factor for budget year "t" assigned to each activity "a" as specified in Table 8-1; ~~and~~

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to each activity;

"a" to account for cap decline as specified in Table 9-2.; and

"$trueup_t$" 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:

$$TrueUp_t = \left(\sum_{a=1}^{n} O_{a,t-2} * B_a * AF_{a,t-2} * c_{a,t-2}\right) - A_{t-2,no\ trueup}$$

Where:

"$O_{a,\,t-2}$" will be calculated by the Executive Officer as the output in year "t-2" as reported to ARB;

"$A_{t-2,no\ trueup}$" is the amount of California GHG allowances directly allocated to the operator of an industrial facility for all activities from budget year "t-2" not including the true-up for that budget year;

"$AF_{a,\,t-2}$" is the assistance factor for budget year "t-2" assigned to each activity "a" as specified in Table 8-1; and

"$c_{a,t-2}$" is the adjustment factor for budget year "t-2" assigned to each activity.

Table 9-1: Product-Based Emissions Efficiency Benchmarks

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Crude Petroleum and Natural Gas Extraction	211111	Thermal EOR Crude Oil Extraction	~~0.0816~~0.0811	Allowances / Barrel of Thermal Crude Oil Eqv.
		Non Thermal Crude Oil Extraction	~~0.0082~~0.0076	Allowances / Barrel of Non Thermal Crude Oil Eqv.
Natural Gas Liquid Extraction	211112	Natural Gas Liquid Processing	~~0.0146~~0.0118	Allowances / Barrel of Natural Gas Liquids Produced
Onshore Natural Gas Processing Plants	211111	Natural Gas Processing ≥ 25MMscf/day	0.0220	Allowances / Barrel of Gas Processed Eqv.
Potash, Soda, and Borate Mineral Mining	212391	Mining and Manufacturing of Soda Ash and Related Products	0.948	Allowances / Short Ton of Soda Ash Equivalent (Soda Ash, Biocarb, Borax, V-Bor, DECA, PYROBOR, Boric Acid, and Sulfate)
All Other Nonmetallic Mineral Mining	212399	Freshwater Diatomite Filter Aids Manufacturing	0.418	Allowances / Short Ton of Freshwater Diatomite Filter Aids

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Fruit and vegetable canning	311421	Tomato Processing		
Poultry Processing	311615	Whole Chicken and Parts Processing		Allowances / Short Ton of Whole Chicken and Parts
		Poultry Deli Product Processing		Allowances / Short Ton of Poultry Deli Product
		Protein Meal Processing		Allowances / Short Ton of Protein Meal
Dried and Dehydrated Food Manufacturing	311423	Dehydrated Garlic Processing	0.665	Allowances / Short Ton of Dehydrated Garlic
		Dehydrated Onion Processing	0.819	Allowances / Short Ton of Dehydrated Onion
		Dehydrated Chili Pepper Processing	1.270	Allowances / Short Ton of Dehydrated Chili Pepper
		Dehydrated Spinach Processing	5.557	Allowances / Short Ton of Dehydrated Spinach
		Dehydrated Parsley Processing	3.178	Allowances / Short Ton of Dehydrated Parsley
Dairy Product Manufacturing	31151	Milk, buttermilk and skim milk processing		Allowances / Short Ton of Milk, Buttermilk and Skim Milk

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
		Cream processing		Allowances / Short Ton of Cream
		Butter processing		Allowances / Short Ton of Butter
Dairy Product Manufacturing	31151	Sweetened Condensed Milk and Evaporated Milk Processing		Allowances / Short Ton of Sweetened Condensed Milk and Evaporated Milk
	31151	Powdered Milk Processing		Allowances / Short Ton of Powdered Milk
	31151	Cheese Processing		Allowances / Short Ton of Cheese
	31151	Lactose Processing		Allowances / Short Ton of Lactose
	31151	Dry Whey Protein Concentrate Processing		Allowances / Short Ton of Dry Whey Protein Concentrate
	31151	Deproteinized Whey Processing		Allowances / Short Ton of Deproteinized Whey
Food Manufacturing	311	Pistachio Processing		Allowances / Short Ton of Pistachios
	311	Almond Processing		Allowances / Short Ton of Almonds

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Snack Food Manufacturing	31191	Fried Potato Chips Processing		Allowances / Short Ton of Fried Potato Chips
		Baked Potato Chips Processing		Allowances / Short Ton of Baked Potato Chips
		Corn Chips Processing		Allowances / Short Ton of Corn Chips
		Corn Curls Processing		Allowances / Short Ton of Corn Curls
		Pretzel Processing		Allowances / Short Ton of Pretzels
Food Manufacturing	311	Juice Manufacturing		
Beet sugar manufacturing	311313	Beet sugar manufacturing	0.611	Allowances / short ton Granulated-Refined Sugar
Breweries	312120	Lager Beer Manufacturing	0.178	Allowances / Thousand Gallons of Lager Beer
Wineries	312130	Spirits Manufacturing		

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Paper (except Newsprint) Mills	322121	Tissue Manufacturing	~~1.140~~0.101	Allowances / Air Dried Short Ton of tissue produced adjusted by water absorption capacity
Paperboard Mills	322130	Recycled Boxboard Manufacturing	~~0.499~~0.516	Allowances / Air Dried Short Ton of recycled boxboard
		Recycled Linerboard (Testliner) Manufacturing	0.562	Allowances / Air Dried Short Ton of recycled linerboard
		Recycled Medium (Fluting) Manufacturing	0.392	Allowances / Air Dried Short Ton of recycled medium
Petroleum Refineries	324110	Petroleum Refining ~~(CO_2 Weighted Tonne)~~	~~0.0295~~	Allowances / ~~CO_2 Weighted Tonne~~
All Other Petroleum and Coal Products Manufacturing	324199	Coke Calcining	~~0.341~~	Allowances/ ~~Short Ton~~ Calcined Coke
Industrial Gas Manufacturing	325120	~~Gaseous Hydrogen Production~~	~~8.85~~	~~Allowances / Metric Ton of Hydrogen Gas~~
		Liquid Hydrogen Production	~~8.85~~	Allowances / ~~Metric Ton~~ of Liquid Hydrogen

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production	0.349	Allowances / Short ton of nitric acid (HNO3 100%)
		Calcium Ammonium Nitrate Solution Production	0.0902	Allowances / Short ton of calcium ammonium nitrate solution
Flat Glass Manufacturing	327211	Flat glass Manufacturing	~~0.471~~0.495	Allowances / Short Ton of Flat Glass Pulled
Glass Container Manufacturing	327213	Container Glass Manufacturing	~~0.264~~ 0.270	Allowances / Short Ton of Container Glass Pulled
Mineral Wool Manufacturing	327993	Fiber Glass Manufacturing	0.394	Allowances / Short Ton of Fiberglass Pulled
Cement Manufacturing	327310	Cement Manufacturing	~~0.718~~ 0.742	Allowances / Short ton of adjusted clinker and mineral additives produced
Lime Manufacturing	327410	Dolime Manufacturing	1.40	Allowances / Short Ton of Dolime Produced
Gypsum Product Manufacturing	327420	Plaster Manufacturing	0.0454	Allowances / Short Ton of Plaster Sold as a Separate Finished Product
		~~Plaster Board~~ Stucco Manufacturing	0.134	Allowances / Short Ton of ~~Plaster Board~~ Stucco used to produce saleable plasterboard

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Iron and Steel Mills	331111	Steel Production Using an Electric Arc Furnace	0.170	Allowances / Short ton of Steel produced using EAF
Secondary smelting and alloying of aluminum	331314	Aluminum and Aluminum Alloy Billet Manufacturing	0.371	Allowances / Short ton of Aluminum and Aluminum alloy Billet
Secondary smelting, refining, and alloying of nonferrous metal (except copper and aluminum)	331492	Lead Acid Battery Recycling		Allowances / Short Ton of Lead and Lead Alloys
Iron Foundries	331511	Ductile Iron Pipe Manufacturing	0.561	Allowances / Short ton of Ductile Iron Pipes
Nonferrous Forging	332112	Seamless Rolled Ring		

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Rolled Steel Shape Manufacturing[1]	331221	Hot Rolled Steel Sheet Production	0.0843	Allowances / Short ton of hot rolled steel
		Picked Steel Sheet Production	~~0.0126~~0.0123	Allowances / Short ton of pickled steel
		Cold Rolled and Annealed Steel Sheet Production	~~0.0313~~0.0520	Allowances / Short ton of cold rolled and annealed steel
		Galvanized Steel Sheet Production	0.0504	Allowances / Short ton of galvanized steel
		Tin Steel Plate Production	~~0.0610~~0.1108	Allowances / Short ton of tin plate
Turbine and Turbine Generator Set Units Manufacturing	333611	Testing of Turbines and Turbine Generator Sets	0.00782	Allowances / Horsepower tested

(c) Energy-Based Allocation Calculation Methodology. The Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the following formula:

$$A_t = \left(S_{Consumed} * B_{Steam} + F_{Consumed} * B_{Fuel} - e_{Sold} * B_{Electricity}\right) * AF_{\sout{a},t} * c_{\sout{a},t}$$

Where:

[1] Cold rolling benchmark values (may affect pickled steel sheet production, cold rolled and annealed sheet production, galvanized steel sheet production and tin steel plate production) are being reviewed based on newly available data.

"A_t" is the amount of California GHG allowances directly allocated to the operator of an industrial facility with an energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"$S_{Consumed}$" is the historical baseline annual arithmetic mean amount of steam consumed, measured in MMBtu, at the industrial facility for any industrial process, including heating or cooling applications. This value shall exclude any steam used to produce electricity. This value shall exclude steam produced from an onsite cogeneration unit;

"B_{Steam}" is the emissions efficiency benchmark per unit of steam, 0.06244 California GHG Allowances/MMBtu Steam;

"$F_{Consumed}$" is the historical baseline annual arithmetic mean amount of energy produced due to fuel combustion at a given facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit. This value shall exclude energy to generate the steam accounted for in the "$S_{Consumed}$" term;

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;

"e_{Sold}" is the historical baseline annual arithmetic mean amount of electricity sold or provided for off-site use, measured in MWhs;

"$B_{Electricity}$" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"$AF_{a,t}$" is the assistance factor for budget year "t" assigned to the facility ~~each~~ activity ~~"a"~~ as specified in Table 8-1; and

"$c_{a,t}$" is the adjustment factor for budget year "t" assigned to the facility ~~each~~ activity ~~"a"~~ to account for cap decline as specified in Table 9-2.

(1) Data Sources.

(A) In determining the appropriate baseline values, the Executive Officer may employ all available data reported to ARB under MRR for data years 2008-2010. If necessary, the Executive Officer will solicit additional data to establish a representative baseline allocation.

(B) Recognition of California Climate Action Registry membership. If a facility reported facility level, third-party verified, greenhouse gas emissions data to the California Climate Action Registry for data years 2000-2007, the Executive Officer may consider these years in determining the representative annual baseline value. If necessary the Executive Officer will solicit additional data for these data years.

(2) Maximum Free Allocation. The Executive Officer shall ensure that the annual amount of California GHG Allowances directly allocated under the energy-based methodology to a covered entity for operations at a facility shall not exceed 110% of the maximum annual level of greenhouse gas emissions, adjusted for steam purchases and sales and electricity sales, emitted during the historical data years used in establishing the baseline allocation for the facility in question.

(3) New Entrants. For cCovered ~~entities of~~ facilities ~~that were not in operation~~ whose emissions exceeded the Cap-and-Trade Program

threshold pursuant to 95812(c)(1) in ~~prior to 2011~~ 2012 or subsequent years, or opted into the program in 2012 or subsequent years, and are eligible for free allocation under the energy-based methodology, allowances shall be ~~assessed a baseline annual allocation based on expected activity levels as~~ determined by the Executive Officer using the following methodology.

(A) Opt-In Covered Entities without Historical Baseline Emissions Data. For opt-in covered entities of facilities that have no historical emissions data reported to ARB under MRR, the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the following formula:

$$A_t = \left(F_{Consumed,est} * B_{Fuel} - e_{sold,est} * B_{Elect}\right) * AF_{t-2} * c_{t-2}$$

Where:

"A_t" is the amount of California GHG Allowances directly allocated to the operator of an industrial facility with an energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"$F_{Consumed,est}$" is the estimated amount of energy produced due to fuel combustion at a given facility, measured in MMBtu. This value shall exclude fuel used to produce steam that is provided or sold offsite. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. The Executive

Officer shall calculate this value utilizing any available data on the design of the facility and equipment;

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;

"$e_{Sold,est}$" is the estimated amount of electricity sold or provided for off-site use, measured in MWh. The Executive Officer shall calculate this value utilizing any available data on the design of the facility and equipment;

"$B_{Electricity}$" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"AF_t" is the assistance factor for budget year "t" assigned to the facility activity as specified in Table 8-1; and

"c_t" is the adjustment factor for budget year "t" assigned to the facility activity to account for cap decline as specified in Table 9-2.

(B) Entities with Transitional Emissions Data. For covered entities or opt-in covered entities that are classified as transitional in the stability formula in 95891(c)(3)(D), the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the following formula:

$$A_t = \left(F_{t-2} * 0.05307 + \left(S_{Purchased,t-2} - S_{Sold,t-2}\right) * 0.06244 - e_{sold,t-2} * 0.431\right) * AF_t * c_t + TrueUp_t$$

Where:

"A_t" is the amount of California GHG Allowances directly allocated to the operator of an industrial facility with an energy-based allocation from budget year "t";

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

"F_{t-2}" is the annual amount of energy produced due to fuel combustion at a given facility for year "t-2", measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit;

"$S_{Purchased,t-2}$" is the annual amount of steam purchased for year "t-2" by the facility in MMBtu as reported to ARB under MRR;

"$S_{Sold,t-2}$" is the annual amount of steam provided or sold for year "t-2" from the facility in MMBtu as reported to ARB under MRR;

"$e_{Sold,t-2}$" is the annual amount of electricity sold for year "t-2" from the facility in MWh as reported to ARB under MRR;

"AF_t" is the assistance factor for budget year "t" assigned to the facility activity as specified in Table 8-1;

"c_t" is the adjustment factor for budget year "t" assigned to the facility activity to account for cap decline as specified in Table 9-2; and

"$trueup_t$" 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 section 95856(h)(1)(D) and 95856(h)(2)(D). This value is calculated using the following formula:

$$TrueUp_t = (BE_{t-2} * AF_{t-2} * c_{t-2} - A_{t-2,no\ trueup})$$

Where:

"$A_{t-2,no\ trueup}$" is the amount of California GHG Allowances directly allocated to the operator of an industrial facility with an energy-based allocation from budget year "t-2" not including the true-up for that budget year;

"t-2" is the year two years prior to year "t";

"AF_{t-2}" is the assistance factor for budget year "t-2" assigned to the facility activity as specified in Table 8-1;

"c_{t-2}" is the adjustment factor for budget year "t-2" assigned to the facility activity to account for cap decline as specified in Table 9-2;

"BE_{t-2}" is the baseline annual greenhouse gas emissions for year "t-2" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_{t-2} = F_{t-2} * 0.05307 + \left(S_{Purchased,t-2} - S_{Sold,t-2}\right) * 0.06244 - e_{sold,t-2} * 0.431$$

Where:

"F_t" is the annual amount of energy produced due to fuel combustion at a given facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit;

"$S_{Purchased,t-2}$" is the annual amount of steam purchased for year "t-2" by the facility in MMBtu;

"$S_{Sold,t-2}$" is the annual amount of steam sold for year "t-2" from the facility in MMBtu; and

"$e_{Sold,t-2}$" is the annual amount of electricity sold for year "t-2" from the facility in MWh.

(C) Entities with Stable Emissions Data. For covered entities or opt-in covered entities classified as stable in the stability formula in 95891(c)(3)(D), the Executive Officer shall calculate the amount of California GHG Allowances directly allocated under the energy-based methodology annually using the methodology in 95891(c). The allocation for all subsequent years shall be determined using this methodology.

1. Data Years. The data years used in determining the appropriate baseline values shall match "t-2", "t-3", and "t-4" used in the stability formula when the emissions were first classified stable. The Executive Officer may employ all available data reported to ARB under MRR. If necessary, the Executive Officer will solicit additional data to establish a representative baseline allocation.

(D) Stability Formula for New Entrants. The following formula classifies the allocation methodology for budget year "t":

$$0.10 \geq \frac{BE_{t-2} - \frac{BE_{t-4} + BE_{t-3}}{2}}{BE_{t-2}} \text{ (Stable)}$$

$$0.10 < \frac{BE_{t-2} - \frac{BE_{t-4} + BE_{t-3}}{2}}{BE_{t-2}} \text{ (Transitional)}$$

Where:

"t" is the budget year from which the direct allocation occurs;

"t-2" is the year two years prior to year "t";

"t-3" is the year three years prior to year "t";

"t-4" is the year four years prior to year "t"; and

"BE_t" is the baseline annual greenhouse gas emissions for year "t" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_t = F_t * 0.05307 + \left(S_{Purchased,t} - S_{Sold,t}\right) * 0.06244 - e_{sold,t} * 0.431$$

Where:

"F_t" is the annual amount of energy produced due to fuel combustion at a given facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit;

"$S_{Purchased,t}$" is the annual amount of steam purchased for year "t" by the facility in MMBtu;

"$S_{Sold,t}$" is the annual amount of steam sold for year "t" from the facility in MMBtu; and

"$e_{Sold,t}$" is the annual amount of electricity sold for year "t" from the facility in MWh.

(4) Facility Closures. Covered entities that are no longer subject to the Cap-and-Trade Program due to reduced emissions or facility closure

as determined pursuant to section 95812(e) shall no longer be eligible to receive allowances.

(d) First Compliance Period Refining Sector Allocation Calculation Methodology. For the budget years 2013-2014, the Executive Officer shall calculate the amount of California GHG allowances allocated to an individual petroleum refinery annually using the following methodology.

(1) Facilities without an EII value. For refineries that did not participate in the 2008 Solomon Energy Review, or that do not have a representative EII value as determined by the Executive Officer, allowances will be allocated using the following ~~equation~~ approach:

(A) Initial allocations for 2013 and 2014 vintage allowances will be allocated using the following equations:

$$\text{If: } O_{X,t-2} * B_R * c_t * AF_{R,t} \leq BE_X * c_t * AF_{R,t}$$
$$\text{Then: } A_{X,t} = O_{X,t-2} * B_R * c_t * AF_{R,t}$$

$$\text{If: } O_{X,t-2} * B_R * c_t * AF_{R,t} > BE_X * c_t * AF_{R,t}$$
$$\text{Then: } A_{X,t} = BE_X * c_t * AF_{R,t}$$

Where:

"$A_{X,t}$" is the allocation to refinery "X" without an EII value for year "t";

"$O_{X,t-2}$" is the output of primary refinery products, in barrels, from refinery "X" in year "t-2";

"B_R" is the benchmark for primary products produced by the refining sector, equal to 0.0462 metric tons of allowances per barrel of primary product;

"$AF_{R,t}$" is the assistance factor for budget year "t" assigned to petroleum refining as specified in Table 8-1; and

"c_t" is the adjustment factor for budget year "t" assigned to petroleum refining to account for cap decline as specified in Table 9-2.

"BE_X" is the baseline average annual greenhouse gas emissions for refinery "X" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_X = GHG + (S_{Purchased} - S_{Sold}) * 0.06244 - e_{Sold} * 0.431$$

"GHG" is the annual arithmetic mean amount of greenhouse gas emissions from the refinery;

"$S_{Purchased}$" is the annual arithmetic mean amount of steam purchased by the refinery in MMBtu;

"S_{Sold}" is the annual arithmetic mean amount of steam sold from the refinery in MMBtu;

"e_{Sold}" is the annual arithmetic mean amount of electricity sold from the refinery in MWh;

To calculate these values, the Executive Officer may employ data reported to ARB for data years 2008-2010. If the facility reported facility-level, third-party verified, greenhouse gas emissions data to the California Climate Action Registry for data years 2006-2007, the Executive Officer may consider these years in determining representative baseline values. If necessary, the Executive Officer will solicit data to establish a representative baseline.

(B) Trueup. In 2015 and 2016, allowance values as calculated for petroleum refineries in Section 95891(b) will be adjusted to account for actual 2013 and 2014 product output. If the entity received initial allowances based on output then the following equation will he used to calculate the true up using actual output:

$$TrueUp_{X,t} = (O_{X,t-2} * B_R * c_{t-2} * AF_{R,t-2}) - A_{X,t-2}$$

Where:

"$TrueUp_{X,t}$" is the amount true-up allowances allocated to account for changes in production or allocation not properly accounted for in prior allocations for refinery "X". 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).

If the entity received initial allocation based on emissions the following true-up equation will be used:

If: $(AE_{X,t-2}) < BE_X * 0.8$

Then: $TrueUp_{X,t} = (AE_X * c_{t-2} * AF_{R,t-2}) - A_{X,t-2}$

(2) Facilities with an EII value. For refineries that participated in the 2008 Solomon Energy Review and have a representative EII value, allowances will be allocated using the following approach:

(A) Initial Allocations. 2013 and 2014 vintage allowances will be allocated using the following equation:

$$A_{Y,t} = BE_Y * DF_{Y,t} * F_t$$

Where:

"$A_{Y,t}$" is the initial allocation to refinery "Y" that has an EII value for year "t";

"BE_Y" is the baseline average annual greenhouse gas emissions for refinery "Y" adjusted for steam purchases and sales and electricity sales using the following equation:

$$BE_Y = GHG + (S_{Purchased} - S_{Sold}) * 0.06244 - e_{Sold} * 0.431$$

"GHG", for the purposes of this calculation, is the annual arithmetic mean amount of greenhouse gas emissions from the refinery;

"$S_{Purchased}$" is the annual arithmetic mean amount of steam purchased by the refinery in MMBtu;

"S_{Sold}" is the annual arithmetic mean amount of steam sold from the refinery in MMBtu;

"e_{Sold}" is the annual arithmetic mean amount of electricity sold from the refinery in MWh;

To calculate these values, the Executive Officer may employ data reported to ARB for data years 2008-2010. If the facility reported facility level, third-party verified, greenhouse gas emissions data to the California Climate Action Registry for data years 2006-2007, the Executive Officer may consider these years in determining representative baseline values. If

necessary, the Executive Officer will solicit data to establish a representative baseline allocation;

"$DF_{Y,t}$" is a distribution factor calculated as:

$$DF_{Y,t} = ((Avg / EII_Y) + Adj_t) / (1 + Adj_t)$$

"Avg" is the weighted average EII for all facilities with EII values calculated as:

$$Avg = \frac{\sum BE_Y}{\sum (BE_Y / EII_Y)}$$

"EII_Y" is the Solomon Energy Intensity Index (EII) for facility Y for 2008, 2009 or 2010 as determined to be representative by the Executive Officer. For the purposes of this calculation, EII values shall be rounded to one digit after the decimal;

"Adj" is an adjustment factor designed to provide the facility with the best EII the most allowances relative to its baseline level:

$$Adj_t = ((Avg/EII_{Best}) * F_t - 1) / (1 - F_t)$$

"EII_{Best}" is the EII of most efficient facility (lowest EII in sector);

"F_t" is a fraction calculated as:

$$F_t = \frac{SA_t - \sum A_{X,t}}{\sum BE_Y}$$

"SA_t" is the allocation to refining sector for year "t" specified in section 95870(e)(2)(A);

(B) True-up 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:

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

Then: ~~$A_{Y,Debit} = 0.8 * [(AE_{Y,2013} + AE_{Y,2014}) - (A_{Y,2013} + A_{Y,2014})]$~~

$\text{TrueUp}_{Y,Debit} = 0.8 * [(AE_{Y,2013} + AE_{Y,2014}) - (A_{Y,2013} + A_{Y,2014})]$

Where:

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

~~"$A_{Y,Debit}$" = A debit (shown as a negative value in the equation above) to be surrendered in addition to the triennial compliance obligation for refinery "Y."~~

"$\text{TrueUp}_{Y,Debit}$" = 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).

(C) True-up Credit. If actual 2013 and 2014 emissions are greater than the assumed baseline emissions, a true-up allocation will be conducted using 2015 vintage allowances and the following equation:

If: $(2 * BE_Y) < (AE_{Y,2013} + AE_{Y,2014})$

Then: ~~$A_{Y,Credit} = (AE_{Y,2013} * DF_{Y,2013} * F_{2013} * AF_{2013} + AE_{Y,2014} * DF_{Y,2014} * F_{2014} * AF_{2014}) - (A_{Y,2013} + A_{Y,2014})$~~

$$\text{TrueUp}_{Y,Credit} = (AE_{Y,2013} * DF_{Y,2013} * F_{2013} * AF_{2013} + AE_{Y,2014} * DF_{Y,2014} * F_{2014} * AF_{2014}) - (A_{Y,2013} + A_{Y,2014})$$

Where:

~~"$A_{Y,Credit}$" = An additional true-up allocation distributed by the Executive Officer to refinery "Y" using 2015 vintage allowances.~~

"$TrueUp_{Y,t}$" is 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).

(e) Allocation to University Covered Entities and Public Service Facilities. The Executive Officer shall calculate the amount of allowances directly allocated to a University or a public service facility using the following formulas:

(1) Budget Year 2015 Allocation. For budget year 2015, the Executive Officer shall calculate the amount of California GHG Allowances directly allocated to eligible University Covered Entities or Public Service Facilities using the following formula.

$$A_{2015} = \left(F_{consumed} * B_{Fuel} - e_{sold} * B_{electricity}\right) * c_t + \sum_{y=2013}^{2014} TrueUp_y$$

Where:

"A_{2015}" is the amount of California GHG allowances directly allocated to a university or public service facility from budget year 2015;

"$F_{consumed}$" is the historical baseline annual arithmetic mean amount of energy produced due to fuel combustion at the facility, measured in MMBtus. The Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C–1 of subpart C, title 40, Code of Federal Regulations, Part 98. This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit.

"B_{Fuel}" is the emissions efficiency benchmark per unit of energy from fuel combustion, 0.05307 California GHG Allowances/MMBtu;
"e_{Sold}" is the historical baseline annual arithmetic mean amount of electricity sold or provided for off-site use, measured in MWhs;
"$B_{Electricity}$" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"c_t" is the adjustment factor for budget year "t" to account for cap decline as specified in Table 9-2.

"TrueUp" is the amount of true-up allowances allocated to account for changes in allocation not properly accounted for in prior allocations. This value of allowances for budget year 2015 shall be allowed to be used for budget year 2013 pursuant to section 95856(h)(1)(D) and 95856(h)(2)(D). This value is calculated using the following formula:

$$TrueUp_y = \left(F_{consumed} * B_{Fuel} - e_{sold} * B_{electricity}\right) * c_y$$

Where:

"y" is the calendar year to which the trueup is correcting, 2013 and 2014.

(2) Budget Years 2016 to 2020 Allocation. For budget years 2016 to 2020, the Executive Officer shall calculate the amount of California GHG Allowances directly allocated to eligible University Covered Entities or Public Service Facility using the following formula.

$$A_t = \left(F_{consumed} * B_{Fuel} - e_{sold} * B_{electricity}\right) * c_t$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to a university or public service facility for budget years "t" from 2016 to 2020.

(3) Data Sources. In determining the appropriate baseline values, the Executive Officer may employ all available data reported to ARB under MRR for data years 2008 through 2013.

(4) Reporting on the Use of Allowance Value. No later than June 30, 2016, and each calendar year thereafter, each university and public service facility shall submit a report to the Executive Officer describing the disposition of any allowance value received in the prior calendar year, and how the allowance value was used to reduce greenhouse gas emissions and achieve additional environmental and economic benefits for California. This report shall include:

(A) The monetary value of allowances received by the university or public service facility. The university or public service facility shall calculate the value of these allowances based on the average market clearing price of the four quarterly auctions held

in the same calendar year that the allowances are allocated; and

(B) How the university or public service facility's disposition of the monetary value of allowances complies with the requirements of California Health and Safety Code sections 38500 et seq.

(f) Adjustment to Allowance Allocation of a Legacy Contract Counterparty. The Executive Officer shall subtract the allowances from the number of California GHG Allowances directly allocated to the Legacy Contract Counterparty pursuant to 95891(b) through 95891(d). If the counterparty was not eligible for allocation pursuant to sections 95891(b) through (d) and the counterparty has a direct corporate association pursuant to section 95833 with any other covered or opt-in entity that was eligible for allocation pursuant to sections 95891(b) through (d) then the entity with a direct corporate association who received industrial allocation pursuant to sections 95891(b) through (d)shall have their allowance allocation adjusted by the equations in this section.

(1) For budget years 2015, the allocation adjustment formula is as follows:

$$Adj_{2015} = \sum_{t=2013}^{2015} A_{LC,t}$$

Where:

"Adj_{2015}" is the allocation adjustment for budget year 2015. This number shall be subtracted from the number of California GHG allowances directly allocated to a legacy contract counterparty or direct corporate associated entity for budget year 2015.

"$A_{LC,t}$" is the allocation amount supplied to the Legacy Contract Generator calculated pursuant to section 95894;

(2) For each budget year after 2015, the allocation adjustment formula is as follows:

$$Adj_{,t} = A_{LC,t}$$

"$Adj_{,t}$" is the allocation adjustment for budget year "t". This number shall be subtracted from the number of California GHG allowances directly allocated to the Legacy Contract Counterparty or the entity with a direct corporate association for budget year "t";

"$A_{LC,t}$" is the allocation received by the legacy contract generator in year t pursuant to section 95894.

(3) If the allocation adjustment is greater than the number of California GHG Allowances directly allocated to a Legacy Contract Counter Party pursuant to sections 95891(b) through (d), then the counter party will have its allowance allocation adjusted to zero. If the counterparty has a direct corporate association pursuant to section 95833 with any other covered or opt-in covered entity that was eligible for allocation pursuant to sections 95891(b) through (d), then the entity with the direct corporate association who received allocation pursuant to section 95891 (b) through (d) shall have its allowance allocation adjusted by the remainder of the adjustment as calculated earlier in this section.

(4) If the counterparty renegotiates the legacy contract to include consideration of greenhouse gas costs, the adjustment will be prorated to include only emissions prior to the date of renegotiation.

Table 9-2: Cap Adjustment Factors for Allowance Allocation

Budget Year	Cap Adjustment Factor (c) for All Other Direct Allocation	Cap Adjustment Factor (c) for Sectors with Process Emissions Greater Than 50%		
		Sector	NAICS	Activity
		Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production
				Calcium Ammonium Nitrate Solution Production
		Cement manufacturing	327310	Cement manufacturing
		Lime manufacturing	327410	Dolime Manufacturing
2013	0.981	0.991		
2014	0.963	0.981		
2015	0.944	0.972		
2016	0.925	0.963		
2017	0.907	0.953		
2018	0.888	0.944		
2019	0.869	0.935		
2020	0.851	0.925		

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95892. Allocation to Electrical Distribution Utilities for Protection of Electricity Ratepayers.

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Table 9-3: Percentage of Electric Sector Allocation Allocated to Each Utility

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
PG&E	IOU	26.02909%	26.34522%	26.01510%	26.21500%	27.21147%	26.91164%	27.21091%	27.22981%
LADWP	POU	14.18332%	14.18925%	14.00829%	14.43473%	14.91438%	15.28169%	14.96326%	14.04837%
SCE	IOU	34.01733%	33.58115%	34.04480%	32.69831%	30.32124%	29.84140%	29.46661%	29.71342%
SDG&E	IOU	7.21940%	6.96087%	6.96792%	7.08933%	7.29010%	7.24815%	7.28721%	7.38964%
SMUD	POU	3.28172%	3.28283%	3.21338%	3.30147%	3.44817%	3.57259%	3.70519%	3.83415%
City of Anaheim	POU	2.07532%	2.12074%	2.11355%	2.19270%	2.20963%	2.27089%	2.30639%	2.35434%
City of Azusa (Azusa Light & Water)	POU	0.18055%	0.18489%	0.18858%	0.19402%	0.20119%	0.20555%	0.21082%	0.21761%
City of Banning	POU	0.09772%	0.10169%	0.10327%	0.10646%	0.11074%	0.11334%	0.11631%	0.12050%
City of Burbank	POU	0.65354%	0.66027%	0.66532%	0.67128%	0.68296%	0.68319%	0.68787%	0.69354%
City of Cerritos	POU	0.01827%	0.01887%	0.01945%	0.02004%	0.02090%	0.02128%	0.02186%	0.02240%
City of Colton	POU	0.24485%	0.25185%	0.25876%	0.26535%	0.27437%	0.27891%	0.28559%	0.29302%
City of Glendale (Water and Power)	POU	0.65850%	0.66238%	0.66100%	0.67150%	0.69049%	0.69592%	0.68391%	0.70039%

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Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
City of Pasadena (Pasadena Water and Power)	POU	0.80141%	0.80710%	0.80920%	0.82057%	0.83784%	0.86949%	0.87876%	0.89190%
City of Riverside	POU	1.12865%	1.13669%	1.13121%	1.17999%	1.20482%	1.24829%	1.27103%	1.30954%
City of Vernon	POU	0.41385%	0.42014%	0.42987%	0.43256%	0.44276%	0.44174%	0.42961%	0.42477%
Imperial Irrigation District	POU	1.77241%	1.81456%	1.82936%	1.90056%	1.97281%	2.00476%	2.05350%	2.11597%
Modesto ID	POU	1.26426%	1.28335%	1.27289%	1.30523%	1.34388%	1.35267%	1.36746%	1.40098%
City of Alameda	POU	0.05321%	0.05746%	0.05675%	0.06140%	0.06253%	0.07244%	0.07403%	0.07561%
City of Biggs	POU	0.00680%	0.00729%	0.00674%	0.00681%	0.00733%	0.00711%	0.00710%	0.00721%
City of Gridley	POU	0.01517%	0.01551%	0.01571%	0.01601%	0.01650%	0.01657%	0.01654%	0.01666%
City of Healdsburg	POU	0.03290%	0.03271%	0.03126%	0.03325%	0.03567%	0.03777%	0.03889%	0.04195%
City of Lodi	POU	0.16616%	0.16780%	0.16385%	0.16740%	0.17419%	0.17518%	0.17494%	0.17995%
City of Lompoc	POU	0.04956%	0.04985%	0.04887%	0.05136%	0.05400%	0.05438%	0.05442%	0.05635%

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
City of Palo Alto	POU	0.35530%	0.35717%	0.34944%	0.35460%	0.36639%	0.36628%	0.36537%	0.37403%
City of Redding	POU	0.44750%	0.50262%	0.50106%	0.51053%	0.52983%	0.54582%	0.54607%	0.55913%
City of Roseville	POU	0.48831%	0.50123%	0.50861%	0.53058%	0.55609%	0.54800%	0.54623%	0.55111%
City of Ukiah	POU	0.03536%	0.03503%	0.03265%	0.03550%	0.03905%	0.04202%	0.04340%	0.04460%
Plumas-Sierra Rural Electric Cooperation	COOP	0.06414%	0.06559%	0.06670%	0.06763%	0.06929%	0.06923%	0.06894%	0.06892%
Port of Oakland	POU	0.03277%	0.03345%	0.03411%	0.03438%	0.03491%	0.03467%	0.03451%	0.03432%
Silicon Valley Power	POU	1.13125%	1.14819%	1.13895%	1.20823%	1.29624%	1.33330%	1.33645%	1.38438%
Truckee-Donner Public Utility District	POU	0.12089%	0.12415%	0.12749%	0.13067%	0.13480%	0.13722%	0.14051%	0.14406%
Turlock Irrigation District	POU	0.94012%	0.97157%	0.98772%	1.01291%	1.05443%	1.06803%	1.06840%	1.08659%
Anza Electric Cooperative, Inc.	COOP	0.02028%	0.02102%	0.04803% ~~0.02181%~~	0.04922% ~~0.02237%~~	0.05093% ~~0.02320%~~	0.05159% ~~0.02348%~~	0.05284% ~~0.02405%~~	0.05386% ~~0.02443%~~
~~Bear Valley Electric Service~~ Golden State Water Company	IOU	0.00006%	0.00006%	0.00006%	0.00007%	0.00007%	0.00007%	0.00007%	0.00007%

Utility Name	Utility Type (1)	Annual % of Total Electric Sector Allocation to Utility							
		2013	2014	2015	2016	2017	2018	2019	2020
City of Needles	POU	0.01027%	0.01086%	0.01148%	0.01183%	0.01248%	0.01250%	0.01284%	0.01316%
City of Rancho Cucamonga	POU	0.02559%	0.02653%	0.02753%	0.02822%	0.02928%	0.02961%	0.03034%	0.03104%
City and County of San Francisco	POU	0.09929%	0.11620%	0.13435%	0.15375%	0.17430%	0.19643%	0.22009%	0.24157%
City of Shasta Lake (Shasta Dam Area Public Utility District)	POU	0.05182%	0.05360%	0.05499%	0.05689%	0.05994%	0.06088%	0.06253%	0.06489%
Lassen Municipal Utility District	POU	0.05079%	0.05279%	0.05492%	0.05638%	0.05866%	0.05927%	0.06075%	0.06219%
Merced Irrigation District	POU	0.17105%	0.17687%	0.18268%	0.18770%	0.19525%	0.19791%	0.20285%	0.20835%
Moreno Valley Utilities	POU	0.03929%	0.04073%	0.04227%	0.04334%	0.04495%	0.04547%	0.04657%	0.04765%
~~Mountain Utilities~~ Kirkwood Meadows Public Utility District	~~IOU~~ POU	0.00306%	0.00317%	0.00329%	0.00337%	0.00350%	0.00354%	0.00362%	0.00369%
Port of Stockton	POU	0.00538%	0.00558%	0.00579%	0.00594%	0.00616%	0.00623%	0.00638%	0.00648%
Power and Water Resource Pooling Authority	POU	0.06650%	0.06899%	0.07018%	0.07365%	0.07980%	0.08118%	0.08378%	0.08727%
~~Sierra Pacific Power Company~~California Pacific	~~POU~~	0.22625%	0.23453%	0.24340%	0.24957%	0.25888%	0.26194%	0.26839%	0.27259%

Electric Company	IOU								
Utility Name	**Utility Type (1)**	**Annual % of Total Electric Sector Allocation to Utility**							
		2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Surprise Valley Electrical Corporation	COOP	0.05381%	0.05578%	0.03167% ~~0.05789%~~	0.03251% ~~0.05936%~~	0.03384% ~~0.06158%~~	0.03419% ~~0.06230%~~	0.03505% ~~0.06384%~~	0.03541% ~~0.06484%~~
Trinity Public Utility District	POU	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%
WAPA	POU	0.33271%	0.35496%	0.37846%	0.39096%	0.41612%	0.41522%	0.42716%	0.43040%
Valley Electric Association, Inc.	COOP	0.00012%	0.00012%	0.00013%	0.00013%	0.00014%	0.00014%	0.00014%	0.00014%
Victorville Municipal	POU	0.02385%	0.02472%	0.02566%	0.02631%	0.02729%	0.02761%	0.02829%	0.02873%
Hercules	POU	0.00656%	0.00674%	0.00687%	0.00711%	0.00747%	0.00761%	0.00782%	0.00813%
City of Industry	POU	0.00910%	0.00945%	0.00982%	0.01008%	0.01047%	0.01058%	0.01085%	0.01101%
Corona	POU	0.06050%	0.06248%	0.06438%	0.06621%	0.06897%	0.06999%	0.07176%	0.07331%
Pittsburg Power (Island)	POU	0.00407%	0.00429%	0.00452%	0.00466%	0.00492%	0.00494%	0.00507%	0.00513%
Eastside	POU	0.00487%	0.00522%	0.00558%	0.00577%	0.00616%	0.00613%	0.00631%	0.00635%
PacifiCorp	IOU	0.75511%	0.77388%	0.79208%	0.81600%	0.84143%	0.86742%	0.89439%	0.92339%
(1) IOU = Investor Owned Electric Utility, POU = Publicly Owned Electric Utility, COOP = Rural Electric Cooperative									

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95893. ~~Reserved for~~ Allocation to Natural Gas ~~Distribution Utilities~~ Suppliers for Protection of Natural Gas Ratepayers. ~~[Repealed]~~

(a) Allocation to Individual Natural Gas Suppliers. For each budget year, each natural gas supplier's allocation will be calculated as follows. Any allowance allocated to natural gas suppliers must be used exclusively for the benefit of retail ratepayers of each such 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.

$$A_{S,t} = E_{2011} * c_{a,t}$$

Where:

"$A_{S,t}$" is the amount of California GHG allowances directly allocated to the natural gas supplier "S" from budget year "t";

"E_{2011}" is the emissions for natural gas supplier "S" for budget year 2011, as calculated using the compliance obligation calculation methods under section 95852(c);

"$c_{a,t}$" is the adjustment factor for budget year "t" to account for cap decline as specified in Table 9-2; and

(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 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:

(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.

(B) The remaining allowances from the allowances allocated in section 95893(a) and the allowances placed into the Limited Use Holding Account in section 95893 (b)(1)(A) will be placed into the Compliance Account.

(c) Monetization Requirement. Within each calendar year beginning in 2015 and after, a natural gas supplier must offer for sale at auction all allowances in its limited use holding account that were issued from budget years that correspond to the current calendar year and from budget years prior to the current calendar year.

(d) Limitations on the Use of Auction Proceeds and Allowance Value.

(1) Proceeds obtained from the monetization of allowances directly allocated to a publicly owned natural gas utility shall be subject to any limitations imposed by the governing body of the utility and to the additional requirements set forth in sections 95893(d)(3) through 95893(d)(5) and 95893(e).

(2) Proceeds obtained from the monetization of allowances directly allocated to public utility gas corporations shall be subject to any limitations imposed by the California Public Utilities Commission and to the additional requirements set forth in sections 95893(d)(3) through 95893(d)(5) and 95893(e).

(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.

(4) Public utility gas corporations shall ensure equal treatment of their procurement and delivery customers and delivery-only customers.

(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to a natural gas supplier, other than for the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited.

(e) Reporting on the Use of Auction Proceeds and Allowance Value. No later than June 30, 2016, and each calendar year thereafter, each natural gas supplier shall submit a report to the Executive Officer describing the disposition of any auction proceeds and allowance value received in the prior calendar year. This report shall include:

(1) The monetary value of auction proceeds received by the natural gas supplier;

(2) How the natural gas supplier's disposition of such auction proceeds complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.;

(3) The monetary value of allowances received by the natural gas supplier which were deposited directly into its compliance account. The natural gas supplier shall calculate the value of these allowances based on the average market clearing price of the four Current Auctions held in the same calendar year that the allowances are allocated; and

(4) How the natural gas supplier's disposition of the monetary value of allowances, including those deposited directly into its compliance account, complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.

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%	30%	35%	40%	45%	50%

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95894. Allocation to Legacy Contract Generators for Transition Assistance.

(a) Demonstration of Eligibility. 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 each subsequent year when applicable:

(1) A letter to ARB stating covered entity name, identification of legacy contract counterparty, and statement requesting transition assistance for emissions reported and verified for the 2012 data year's legacy contract emissions.

(2) Copy of the following portions from the legacy contract for which it is seeking an allocation;

(A) Dates of effective commencement and cessation of terms of contract.

(B) Terms governing price per unit of product

(C) Signature page

(3) An attestation under penalty of perjury under the laws of the State of California that:

(A) Each 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;

(B) The legacy contract was originally executed prior to September 1, 2006, remains in effect, and has not been amended since that date to change the terms governing the price or amount of electricity or Qualified Thermal Output sold, the GHG costs, or the expiration date;

(C) The operator of 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.

(4) Data requested pursuant to Section 95894(d).

(5) 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.

(b) Determination of Eligibility. Upon receipt of the information required by paragraph (a) of this section, the Executive Officer shall determine whether the party submitting such information has demonstrated that it is eligible to receive a direct allocation of allowances pursuant to this section and shall notify that party by September 30, 2014 or within 30 days of the effective date of this regulation for allocation in 2014 and by September 30th of each subsequent year if it is eligible to receive an allocation calculated pursuant to section 95894(c) or 95894(d) for the following

compliance year.

(c) If the counterparty or a direct corporate association of the counterparty is a covered entity or opt-in covered entity that is in a sector listed in Table 8-1, the following formulae apply based on the type of generation facility

(1) For stand-alone generation facilities, the following equations apply:

$$TrueUp_{2015} = (EEm_{lc} * c_{2013}) + (EEm_{lc} * c_{2014}) + (EEm_{lc} * c_{2015})$$

Where

"$TrueUp_{2015}$" is the amount of true up allowances allocated from budget year 2015 and allowed to be used for budget years 2013 and 2014 pursuant to sections 95856(h)(1)(D) and 95876(h)(2)(D) ;

"EEm_{lc}" is the emissions reported, in MTCO2e, associated with electricity sold under the legacy contract in 2013; and

"c_t" is the cap adjustment factor for budget year "t"

For years after 2015, the following equation applies:

$$A_t = \left(EEm_{lc,t-2} * c_{a,t} * AF_{lcc,t}\right) + TrueUp$$

Where:

"A_t" is the amount of California GHG allowances directly allocated to the Legacy Contract Generator subject to a Legacy Contract from budget year "t";

$$TrueUp_t = \left(EEm_{lc,t-2} * c_{a,t-2} * AF_{lcc,t-2}\right) - A_{t-2,no\ trueup}$$

Where:

"$Aft_{lcc,t}$" is the assistance factor associated with the legacy contract counterparty or direct corporate associated entity of the counterparty for budget year t

"$A_{t\text{-}2,no\ trueup}$" is the amount of California GHG allowances directly allocated to the Legacy Contract Generator subject to a Legacy Contract from budget year "t-2" not including the true-up for that budget year;

(2) For generators subject to 95894(c) but not covered in 95894(c)(1), the following equations apply :

$$TrueUp_{2015} = \left((Q_{lc} * B_s + E_{lc} * B_e) * C_{a,2013}\right) + ((Q_{lc} * B_s + E_{lc} * B_e) * C_{a,2014}) + ((Q_{lc} * B_s + E_{lc} * B_e) * C_{a,2015})$$

Where:

"$TrueUp_{2015}$" is the amount of true-up allowances allocated from budget year 2015 and allowed to be used for budget years 2013 and 2014 pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"Q_{lc}" is the Legacy Contract Qualified Thermal Output in MMBtu sold under a legacy contract in data year 2013, as reported to MRR;

"E_{lc}" is the electricity, in MWh, sold under the legacy contract in data year 2013;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of Legacy Contract Qualified Thermal Output, 0.06244 California GHG Allowances/MMBtu thermal; and

"C_t" is the cap adjustment factor for budget year "t" as specified in table 9-2.

For years after 2015, the following formula applies:

$$A_t = ((Q_{lc,t-2} * B_s + E_{lc,t-2} * B_e) * AF_{lcc,\ t} * C_t) + TrueUp_t$$

Where:

$$TrueUp_t = ((Q_{lc,\ t-2} * B_s + E_{lc,\ t-2} * B_e) * AF_{lcc,\ t-2} * C_{t-2}) - A_{t-2,no\ trueup}$$

"A_t" is the amount of California GHG allowances directly allocated to the Legacy Contract Generator subject to a Legacy Contract from budget year "t";

"$Q_{lc,\ t-2}$" is the Legacy Contract Qualified Thermal Output in MMBtu sold under a legacy contract in data year t-2, as reported under the MRR;

"E_{lc}" is the electricity, in MWh, sold under the legacy contract;

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"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of Legacy Contract Qualified Thermal Output, 0.06244 California GHG Allowances/MMBtu thermal;

"C_t" is the cap decline factor for budget year "t" as specified in table 9-2;

"C_{t-2}" is the is the cap decline factor for the budget year two years prior to year "t" as specified in Table 9-2.

"$A_{t-2,no\ trueup}$" is the amount of California GHG allowances directly allocated to the Legacy Contract Generator subject to a Legacy Contract from budget year "t-2" not including the true-up for that budget year;

(d) For legacy contracts not covered in 95894(c), the following formulae shall apply:

(1) For stand alone generation facilities:

$$TrueUp_{2015} = (EEm_{lc} * c_{2013}) + (EEm_{lc} * c_{2014})$$

Where

"TrueUp$_{2015}$" is the amount of true up allowances allocated and allowed to be used for budget year "t-2" and "t-1" pursuant to sections 95856(h)(1)(D) and 95876(h)(2)(D) in vintage 2015 allowances based on calendar year 2012 Legacy Contract Emissions reported and verified pursuant to MRR;

"EEm $_{lc}$" is the emissions reported, in MTCO2e, associated with electricity sold under the legacy contract in 2012; and

"c_t" is the adjustment factor for budget year "t".

(2) For legacy contract generators not covered in 95894(c) or 95894(d)(1):

$$TrueUp_{2015} = \left((Q_{lc} * B_s + E_{lc} * B_e) * c_{2013}\right) + \left((Q_{lc} * B_s + E_{lc} * B_e) * c_{2014}\right)$$

Where:

"TrueUp$_{2015}$" is the amount of true-up allowances allocated from budget year 2015 and allowed to be used for budget years 2013 and 2014pursuant to sections 95856(h)(1)(D) and 95856(h)(2)(D);

"Q_{lc}" is the Legacy Contract Qualified Thermal Output in MMBtu sold under a legacy contract in data year 2012, as reported to MRR;

"E_{lc}" is the electricity, in MWh, sold under the legacy contract in data year 2012;

"B_e" is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

"B_s" is the emissions efficiency benchmark per unit of Legacy Contract Qualified Thermal Output, 0.06244 California GHG Allowances/MMBtu thermal; and

"c_t" is the cap decline factor for budget year "t" as specified in table 9-2.

(e) Data Sources. In determining the appropriate values for section 95894(c) and 95894(d), the Executive Officer may employ all available data reported to ARB under MRR for 2012 and all other relevant data, including invoices, demonstrating the amount of electricity and Qualified Thermal Output sold or provided for off-site use that does not include a carbon cost in the budget year for which it is seeking an allocation. If necessary, the Executive Officer will solicit additional data to establish a representative allocation. The operator of the Legacy Contract Generator must provide the additional data upon request by the Executive Officer.

(f) Contract Expiration or Amendment or Renegotiation. Once a legacy contract expires or the legacy contract generator closes operations or the contract has been renegotiated to consider GHG costs, the legacy contract generator will no longer be eligible for free allocation and allocation will be prorated for the time in which the contract was eligible.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95895. Allocation to Public Wholesale Water Agencies for Protection of Water Ratepayers.

(a) Allocation to Public Wholesale Water Agencies. The allowances allocated to each public wholesale water agency from each budget year from 2015 to 2020 shall be the amount specified in Table 9-5.

Table 9-5: Allocation to Each Public Wholesale Water Agency

Agency Name	Annual Allocation					
	2015	2016	2017	2018	2019	2020
Metropolitan Water District	136,491	22,086	14,643	14,559	3,908	3,908

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 10: Auction and Sale of California Greenhouse Gas Allowances

§ 95910. Auction of California GHG Allowances.

(a) Timing of the Allowance Auctions.

(1) In 2012, an auction will held on November 14.

(2) Beginning in 2013 and through 2014, the auctions shall be conducted on the twelfth business day in California or a jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12 of the second month of each calendar quarter.

(3) Beginning in 2015, auctions shall be conducted on the schedule pursuant to Appendix C.

(b) General Requirements.

(1) Allowances allocated to the Auction Holding Account pursuant to section 95870(b)(1)-(2) and (fj) will be designated to specific auctions pursuant to section 95910(c).

(2) An allowance may be designated for auction prior to or after its vintage year.

(c) Allowances from future vintages will be auctioned separately from allowances from current and previous vintages each quarter.

(1) Auction of Allowances from the Current and Previous Budget Years.

(A) This auction will be known as the Current Auction.

(B) Beginning in 2013, one quarter of the allowances allocated for auction from the current calendar year's budget and the allowances designated pursuant to Section 95911(f)(3)(D) will be designated for sale at each Current Auction.

(C) The Current Auction will include allowances consigned to auction pursuant to section 95910(d).

(D) The Current Auction may include allowances from the current and previous budget years which remained unsold at previous auctions and which are designated for auction pursuant to section 95911(f)(3).

(2) Auction of Allowances from Future Budget Years.

(A) This auction will be known as the Advance Auction.

(B) At the one Advance Auction taking place in 2012, the Executive Officer will designate for sale all of the allowances allocated for Advance Auction from the 2015 budget.

(C) Beginning in 2013, one quarter of the allowances allocated for Advance Auction from the budget year three years subsequent to the current calendar year will be designated for sale at each Advance Auction.

(D) The Advance Auction will include allowances which were returned to the Auction Holding Account following an Advance Auction which resulted in unsold allowances, and which are designated for auction pursuant to section 95911(f)(3).

(d) Auction of Consigned Allowances.

(1) An entity may consign allowances to the Executive Officer for sale at the quarterly auctions only from a limited use holding account.

(2) When the Executive Officer withdraws compliance instruments from accounts closed pursuant to section 95831(c), accounts containing allowances in excess of the holding limit pursuant to section 95920(b)(5), or accounts suspended or revoked pursuant to section 95921(g)(3):

(A) Allowances shall be consigned to the next auction;

(B) If, after review, the Executive Officer determines the withdrawn ARB offset credits are valid, the Executive Officer will retire them, withdraw a similar number of allowances from the Auction Holding Account, and consign those allowances to auction in place of the retired ARB offset credits.

(3) Each consigning entity agrees to accept the auction settlement price for allowances sold at auction.

(4) Deadline for Consignment.

(A) For the auction conducted in 2012, allowances designated for consignment pursuant to section 95892(c) must be transferred to the Auction Holding Account at least 10 days before the auction.

(B) Beginning in 2013 and through 2014, allowances consigned to auction through a transfer to the Auction Holding Account at least 75 days prior to the regular quarterly auction will be offered for sale at that auction. This transfer must be completed by 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on the 75th day before the auction.

(C) Beginning in 2015, allowances designated for consignment pursuant to section 95892(c) and 95893(c) must be transferred to the Auction Holding Account at least 75 days before the auction as scheduled in Appendix C. This transfer must be

completed by 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on the 75th day before the auction.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95911. Format for Auction of California GHG Allowances.

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(c) Method for Setting the Auction Reserve Price.

(1) The Auction Reserve Price for vintage 2013 allowances auctioned in 2012 will be $10 per allowance. For Advance Auctions conducted in 2012, the Reserve Price shall be $10 per allowance for vintage 2015 allowances.

(2) Beginning in 2012, and each year thereafter, the Auction Administrator will announce the Auction Reserve Price for auctions to be conducted the following calendar year on the first day in December that is a business day in California. The Reserve Price shall be stated in U.S. dollars.

(3) The Auction Administrator will calculate the Auction Reserve Price using the following procedure:

(A) The Auction Reserve Price in U.S. dollars shall be the U.S. dollar Auction Reserve Price for the previous calendar year increased annually by 5 percent plus the rate of inflation as measured by the most recently available twelve months of the Consumer Price Index for All Urban Consumers.

(B) Prior to the opening of the auction window on the day of the auction, the Auction Administrator shall announce the Auction Reserve Price.

(C) The auction administrator shall set the exchange rate as the most recently available noon daily buying rate for U.S. and Canadian dollars as published by the Bank of Canada, and shall

announce the exchange rate prior to the opening of the auction window.

(D) The Auction Reserve Price in Canadian dollars shall be the Canadian dollar Auction Reserve Price for the previous calendar year increased annually by 5 percent plus adjusted in the manner provided for in section 83.3 of the Financial Administration Act (R.S.Q., c. A-6.001) of Quebec.

(E) The auction administrator will use the announced exchange rate to convert to a common currency the Auction Reserve Prices previously calculated separately in U.S. and Canadian dollars. The auction administrator will set the Auction Reserve Price equal to the higher of the two values.

(4) The Auction Reserve Price will be announced prior to the opening of the auction window at 10 a.m. Pacific Standard Time (or Pacific Daylight Time when in effect) on the day of the auction, and will be in effect until the window closes at 1 p.m. Pacific Standard Time (or Pacific Daylight Time when in effect). The opening of the bidding window may be delayed or paused for no more than one hour by the Executive Officer due to technical systems failures.

(5) The Auction Reserve Price in section 95911(c)(2) will be announced on the first day in December that is a business day in California and in any jurisdiction operating an External GHG ETS to which California has linked pursuant to subarticle 12 and the Reserve Price shall also be stated in the currency (or currencies) used in an External GHG ETS to which California has linked pursuant to subarticle 12.

(d) Auction Purchase Limit.

(1) The auction purchase limit is the maximum number of allowances offered at each quarterly auction which can be purchased by any entity or group of entities with a direct corporate association pursuant to section 95833.

(2) The auction purchase limit in section 95911(d)(4) will apply to auctions conducted from January 1, 2012 through December 31, 2014.

(3) For the Advance Auction of future vintage allowances conducted pursuant to section 95910(c)(2) the purchase limit is 25 percent of the allowances offered for auction.

(4) For the auction of current vintage allowances conducted pursuant to section 95910(c)(1):

(A) The purchase limit for covered entities and opt-in covered entities will be ~~15~~ 20 percent of the allowances offered for auction;

(B) The purchase limit for electrical distribution utilities will be 40 percent of the allowances offered for auction; and

(C) The purchase limit for all other auction participants is four percent of the allowances offered for auction.

(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 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.

(6) The auction purchase limit for auctions conducted from January 1, 2015 through December 31, 2020 will be 4 percent of the allowances offered for auction for voluntarily associated entities or group of voluntarily associated entities with a direct corporate association pursuant to section 95833.

(e) Determination of Winning Bidders and Settlement Price. The following process shall be used to determine winning bidders, amounts won, and a single auction settlement price:

(1) Each bid will consist of a price and the quantity of allowances, in multiples of 1,000 CA GHG Allowances, desired at that price.

(2) Each bidder may submit multiple bids.

(3) Beginning with the highest bid price, bids from each bidder will be considered in declining order by price, and the auction operator shall reject a bid for a bundle of 1,000 allowances:

(A) If acceptance of the bid would result in violation of the purchase limit pursuant to sections 95911(d) and 95914;

(B) If acceptance of the bid would result in violation of the holding limit pursuant to sections ~~95914 and~~ 95920(b); or

(C) If acceptance of the bid would result in a total value of accepted bids for an auction participant greater than the value of the bid guarantee submitted by the auction participant pursuant to section 95912(ij).

(4) Bids from all bidders will be ranked from highest to lowest by price. Beginning with the highest bid and proceeding to successively lower bids, entities submitting bids at each price will be sold allowances until:

(A) The next lower bid price is less than the auction reserve price, in which case the current price becomes the auction settlement price; or

(B) The total quantity of allowances contained in the bids at the next lower bid price is greater than or equal to the number of allowances yet to be sold, in which instance, the next lower bid price becomes the auction settlement price and the procedure for resolution of tie bids in section 95911(e)(5) shall apply.

(5) Resolution of tie bids. If the quantity of allowances contained in the bids placed at the auction settlement price is greater than the quantity of allowances available to be sold at that price, then:

(A) The auction administrator will calculate the share of the remaining allowances to be distributed to each entity bidding at the auction settlement price by dividing the quantity bid by that entity and accepted by the auction administrator by the total quantity of bids at the settlement price which were accepted by the auction administrator;

(B) The auction administrator will calculate the number of allowances distributed to each bidding entity by multiplying the bidding entity's share calculated in section 95911(e)(5)(A) above by the number of allowances remaining, rounding the number down to the nearest whole number; and

(C) To distribute any remaining allowances, the auction administrator will assign a random number to each entity bidding at the auction settlement price. Beginning with the lowest random number, the auction administrator will assign one allowance to the last bundle purchased by each entity until the remaining allowances have been assigned.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95912. Auction Administration and Participant Application.

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(b) The Executive Officer may direct that the California GHG allowances designated for auction be offered through an auction conducted jointly with other jurisdictions to which California links pursuant to subarticle 12, provided the joint auction conforms ~~with~~to this article.

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(d) Auction Participation Application Requirements.

(1) The Executive Officer must approve an entity's auction participant application before that entity may participate in an auction.

(2) An entity applying for approval as an auction participant must be registered into the Cap-and-Trade Program as provided in section 95830.

(3) An entity whose holding account has been revoked or is currently suspended pursuant to section 96011 cannot participate in an auction. An individual associated pursuant to section 95830, 95832, and 95833 with an entity whose holding account has been revoked or is currently suspended pursuant to section 96011 cannot participate in an auction.

(4) An entity will be required to complete and auction participant application at least 30 days prior to an auction in which it intends to participate. This application must be completed by 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect). The entity must provide information and documentation including:

(A) Information and documentation regarding the corporate identity, ownership, and capital structure of the applicant;

(B) The existence of any direct or indirect corporate associations pursuant to sections 95833 and 95914(d);

(C) An allocation of the purchase limit among associated entities as defined in section 95833, or change in the existing allocation of the purchase limit among associated entities, if applicable;

(D) An allocation of the holding limit among associated entities as defined in section 95833, or a change in the existing allocation of the holding limit among associated entities, if applicable;

(E)~~(C)~~ 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 ~~The identification of~~ of any previous or ongoing ~~pending~~ 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; and

(F)~~(D)~~ The applicant's holding account number.

(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 within 15 days after an auction, may be denied participation in the auction.

(6)~~(5)~~ Prior to participating in an auction, any primary or alternate account representative that will be submitting bids on behalf of entities eligible to participate in an auction ~~Reserve sales~~ must have already:

(A) Complied with the Know-Your-Customer requirements of section 95834; and

(B) Submitted the additional information required by the financial services administrator contained in Appendix A of this subarticle.

(e) Maintenance and Modification of Auction Participation Approval.

(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, there is a material change in the entity's Cap-and-Trade Program registration pursuant to section 95830, or the Executive Officer has made a determination restricting an entity's auction participation pursuant to section 95914.

(2) 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 change should be reported by 5 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on the 30th day before an auction.

(f) 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.

(~~f~~g) An entity approved for auction participation may not communicate information on auction participation with any other entity that is not part of an association disclosed pursuant to section 95914, except as requested by the Auction Administrator to remediate an auction application.

(~~g~~h) Protection of Confidential Information. To the extent permitted by state law, the Executive Officer, the Auction Administrator, and the financial services administrator will treat the information contained in the auction application and not listed for release pursuant to section 95912(j~~k~~)(5) as confidential business information.

(~~h~~i) All bids will be considered binding offers for the purchase of allowances under the rules of the auction.

(i~~j~~) Auction participants must provide a bid guarantee to the financial services administrator at least 12 days prior to the auction.

(1) The bid guarantee must be in one or a combination of the following forms:

(A) Cash in the form of a wire transfer~~ or certified funds, such as a bank check or cashier's check~~; or

(B) An irrevocable letter of credit issued by a financial institution with a United States banking license; or

(C) A bond issued by a financial institution with a United States banking license~~.~~; or

(D) A Surety Bond issued by an institution named in the current list of "Surety Companies Acceptable in Federal Bonds" as published in the Federal Register by the Audit Staff Bureau of Accounts, U.S. Treasury Department.

(2)(~~D~~) The bid guarantee submitted by any entity registered with California will be in U.S. dollars.

(3) A bid guarantee submitted in any form other than cash must be payable within one business day of payment request.

(4)~~(E)~~ The bid guarantee will be in the currency used by the jurisdiction with which the entity has registered.

(2~~5~~) The amount of the bid guarantee must be greater than or equal to the maximum value of the bids to be submitted.

(A) The value of a set of bids equals the cumulative quantity of bids submitted at or above a price times that price. The value of the set of bids is calculated at each price at which the bidder will submit a bid.

(B) The maximum value of a set of bids is the highest value of a set of bids calculated at each price at which the bidder will submit a bid.

(C) If the auction participant submits a single bid guarantee to cover bids in both the Current and Advance Auctions, the amount of the single bid guarantee must be greater than or equal to the combined maximum value of the Current and Advance Auction bids to be submitted.

(D) Submission of a bid guarantee that is less than the maximum value of the bids to be submitted would result in a violation pursuant to section 95914.

(3~~6~~) The bid guarantee will be made payable to the financial services administrator.

(4~~7~~) The bid guarantee will expire no sooner than 21 days after the auction date.

(5~~8~~) The financial services administrator will evaluate the bid guarantee and inform the auction administrator of the value of the bid guarantee once it is found to conform to this section and is accepted by the Executive Officer.

(6~~9~~) If an entity has submitted more than one form of bid guarantee then the financial services administrator will apply the instruments to the unpaid balance in the order the instruments are listed in section 95912(~~ij~~)(1).

(~~7~~10) If the auction participant submits a single bid guarantee instrument to cover bids in both the Current and Advance Auctions, the auction administrator will apply the value of the bid guarantee to the Current Auction first when accepting bids pursuant to section 95911(e)(3). The remaining value of the bid guarantee will be used to determine acceptance of bids into the Advance Auction.

(jk) After the auction administrator has notified the Executive Officer of the results of the auction the Executive Officer will:

(1) Review the conduct of the auction by the auction administrator, then certify whether the auction met the requirements of this article;

(2) After certification, direct the financial services administrator to:

(A) Notify each winning bidder of the auction settlement price, the number of allowances purchased, the total purchase cost, and the deadline and method for submitting payment;

(B) Collect cash payments from winning bidders within seven days of notifying them of the auction results;

(C) Use the bid guarantee to cover payment for allowance purchases by any entity that fails to make cash payment within seven days after bidders are notified of results and place the proceeds into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8 ~~Air Pollution Control Fund~~;

(D) Deposit auction proceeds from sales of ARB allowances sold at auction into the Greenhouse Gas Reduction Fund created pursuant to Government Code section 16428.8 ~~Air Pollution Control Fund~~;

(E) Distribute auction proceeds to entities that consigned allowances for auction pursuant to section 95910(d); and

(F) Return any unused bid guarantee.

(3) Upon determining that the payment for allowances has been deposited into the Greenhouse Gas Reduction Fund created pursuant to

Government Code section 16428.8, ~~Air Pollution Control Fund~~ or transferred to entities that consigned allowances, transfer the ~~serial numbers of the~~ allowances purchased into each winning bidder's Holding Account, or to its Compliance Account if needed to comply with the holding limit;

(4) Inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances purchased at auction; and

(5) Following the auction, the Executive Officer will publish at www.arb.ca.gov the following information:

(A) The names of the bidders;

(B) Auction settlement price; and

(C) Aggregated or distributional information on purchases with the names of the entities withheld.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code~~,~~ and Section 16428.8, Government Code.

§ 95913. Sale of Allowances from the Allowance Price Containment Reserve.

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(b) Entities registered in an External GHG ETS to which California has linked pursuant to subarticle 12 are not eligible to purchase from the California Reserve~~If California links to an external greenhouse gas emissions trading system (GHG ETS) pursuant to subarticle 12, the linkage agreement will specify whether covered entities in the linked GHG ETS will be eligible to purchase from a jointly operated Reserve, or whether each GHG ETS will operate separate Reserves~~.

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(d) Timing of Reserve Sales.

(1) The first Reserve sale will be conducted on March 8, 2013.

(2) Subsequent Reserve sales through 2014 shall be conducted on the first business day six weeks after each quarterly allowance auction scheduled pursuant to section 95910.

(3) Beginning in 2015, Reserve sales shall be conducted pursuant to the schedule in Appendix C.

(34) The Reserve sale administrator shall provide all eligible participants with notice of the number of allowances available for sale and the terms of the sale at least ~~four weeks~~ 30 days prior to the sale.

(45) The subsequent Reserve sales in section 95913(~~(~~d)(2), shall be conducted on the first day six weeks after each quarterly allowances auction scheduled pursuant to section 95910 that is also a business day in California and any linked jurisdiction operating an External GHG ETS to which ~~Califirnia~~California has linked pursuant to subarticle 12.

(6) Section 95913(d)(5) will not apply after January 1, 2015.

(e) Reserve Sale Intent to Bid Notification Requirements

(1) An entity that intends to participate in a reserve sale must inform the Reserve Sale Administrator at least 20 days prior to a reserve sale of its intent to bid in that reserve sale, otherwise the entity may not participate in that reserve sale.

(2) An entity with any auction application information listed in subsection 95912(d)(4) above or account application information listed in section 95830 that changes 20 days prior to a reserve sale, or 15 days after a reserve sale, may be denied participation in a reserve sale.

(~~e~~f) Reserve Tiers.

(1) Creation of Reserve Tiers. Prior to the first Reserve sale, the Executive Officer shall divide allowances allocated to the Reserve from section 95870(a) into three equal-sized tiers.

(2) The Reserve sale administrator shall offer all of the allowances in the Reserve at each Reserve sale.

(3) Reserve Tier Prices. Sales of Reserve allowances in calendar year 2013 shall be conducted at the following prices:

(A) Allowances from the first tier shall be offered for $40 per allowance;

(B) Allowances from the second tier shall be offered for $45 per allowance; and

(C) Allowances from the third tier shall be offered for $50 per allowance.

(4) Increase in Reserve Tier Prices. In calendar years subsequent to 2013, allowances from each tier shall be offered at prices equal to the tier prices from the previous calendar year increased by five percent plus the rate of inflation as measured by the most recently available twelve month value of the Consumer Price Index for All Urban Consumers.

(5) This provision only applies to the Reserve sale immediately preceding the compliance obligation instrument surrender on November 1. Pursuant to section 95870(j)(1), allowances will be made available at the highest price tier of the Allowance Price Containment Reserve if the amount of accepted bids at the highest price tier exceeds the number of allowances in that tier.

(A) The allowances will be made available no sooner than the Reserve sale immediately preceding the compliance obligation instrument surrender on November 1, 2015.

(B) If the quantity of allowances from section 95870(a) allocated to the highest price tier plus the allowances defined in section 95870(j)(1) is equal to or greater than the quantity of accepted bids in the highest price tier then all accepted bids for the highest price tier will be filled.

(C) If the quantity of accepted bids at the highest price tier exceeds the allowances from section 95870(a) plus the allowances defined in section 95870(j)(1), allowances will be sold through the procedure outlined in section 95913(h)(5).

(D) The accepted bids at the highest price tier will be filled first with allowances from section 95870(a) allocated to the highest price tier if available.

(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. The allowances defined in section 95870(j)(1) sold pursuant to this section shall first reduce the quantity of allowances defined in section 95870(b) if available and then will reduce the quantity of allowances defined in section 95870(j)(2).

(F) Allowances sold pursuant to this section will be surrendered as allowances purchased from an Allowance Price Containment Reserve sale as specified in section 95856(b)(2)(A) and section 95856(h).

(~~f~~g) At least 12 days before the scheduled sale, by 5 p.m. Pacific Standard Time (or Pacific Daylight Savings Time, when in effect), an entity intending to participate in a Reserve sale must submit to the financial services administrator a bid guarantee, payable to the financial services administrator, in an amount greater than or equal to the sum of the maximum value of the bids to be submitted by the entity.

(1) The maximum value of a set of bids is the quantity bid at each tier times the tier price, summed across the three tiers.

(2) The bid guarantee must be in one or a combination of the following forms:

(A) Cash in the form of a wire transfer ~~or certified funds, such as a bank check or cashier's check~~; or

(B) An irrevocable letter of credit issued by a financial institution with a United States banking license; or

(C) A bond issued by a financial institution with a United States banking license.; or

(D) A Surety Bond issued by an institution named in the current list of "Surety Companies Acceptable in Federal Bonds" as published in the Federal Register by the Audit Staff Bureau of Accounts, U.S. Treasury Department.

(3) A bid guarantee submitted in any form other than cash must be payable within one business day of payment request.

(34) The bid guarantee will be made payable to the financial services administrator.

(45) The bid guarantee will expire no sooner than twenty-one days after the Reserve sale.

(56) The financial services administrator will evaluate the bid guarantee and inform the Reserve sale administrator of the value of the bid guarantee once it is found to conform to this section and is accepted by the Executive Officer.

(7) The Executive Officer may revise the timing of reserve sales intent to bid notification requirements in subsection 95913(e) and bid guarantee submittal requirements in subsection 95913(g) to ensure a minimum of four business days is available between the intent to bid notification and bid guarantee submittal due dates.

(gh) Purchase Determinations.

(1) The reserve sale administrator will conduct sales from each tier in succession, beginning with the lowest priced tier and proceeding to the highest priced tier.~~, until either all allowances are sold from the reserve or all the accepted bids are filled.~~

(A) The Reserve sale will continue until either all allowances are sold from the Reserve pursuant to section 95870(a) or all the accepted bids are filled.

(B) 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).

(2) The Reserve sales window will open at 10 a.m. Pacific Standard Time (or Pacific Daylight Time, when in effect) on the day of the sale, and bids may be submitted until the window closes at 1 p.m. Pacific Standard Time (or Pacific Daylight Time, when in effect).

(A) Each bid will consist of the price, in U.S. dollars, equal to one of the three tiers and a quantity of allowances in multiples of 1,000 allowances.

(B) An entity may submit multiple bids.

(3) The reserve sale administrator will only accept a bid for a bundle of 1,000 allowances:

(A) If acceptance of the bid would not result in violation of the holding limit pursuant to section 95920(b);

(B) If acceptance of the bid would not result in a total value of accepted bids for a covered entity greater than the value of the bid guarantee submitted by the covered entity pursuant to section 95913(~~f~~g); or

(C) If the bid entered by an entity for a tier is for a quantity less than or equal to the number of allowances available for sale in that tier.

(4) If the sum of bids at the tier price which are accepted by the reserve sale administrator is less than or equal to the number of allowances in the tier, then:

(A) The reserve sale administrator will sell to each covered entity the number of allowances for which the entity submitted bids for that tier which were accepted by the reserve sale administrator; and

(B) If allowances remain in the tier after the sales pursuant to section 95913(g~~h~~)(4)(A) are completed, the reserve sale

administrator will assign a random number to each bundle of 1,000 allowances for which entities submitted a bid for the tier above the current tier being sold. Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the reserve sale administrator shall sell allowances to the bidder assigned the random number until the remaining allowances in the tier are sold or all accepted bids have been fulfilled. The price for the allowances sold under this procedure will be the price for the tier from which they are sold, not the bid placed.

(5) If the sum of bids accepted by the reserve sale administrator for a tier is greater than the number of allowances in the tier, the reserve sale administrator will determine the total amount to be distributed from the tier to each covered entity using the following procedure:

(A) The reserve sale administrator will calculate the share of the tier to be distributed to each bidding entity by dividing the quantity bid by that entity and accepted by the reserve sale administrator by the total quantity of bids which were accepted by the reserve sale administrator; and

(B) The reserve sale administrator will calculate the number of allowances distributed to each bidding entity from the tier by multiplying the bidding entity's share calculated in section 95913 (~~g~~h)(5)(A) above by the number of allowances in the tier, rounding the number down to the nearest whole number.

(6) After completing the sales for each tier the reserve sale administrator will repeat the processes in sections 95913(~~g~~h)(4) and (~~g~~h)(5) above for the next highest price tier until all bids have been filled or until the Reserve is depleted. At that time the reserve sale administrator will inform the Executive Officer of the sales from the Reserve to each participant.

(~~h~~i) Resolution of Sales.

(1) After reviewing the conduct of the sale by the Reserve sale administrator, the Executive Officer will certify whether the Reserve sale met the requirements of this article.

(2) Upon certification of the sale results, the Executive Officer will authorize the financial services administrator to:

(A) Notify Reserve sale participants of their purchases and total purchase cost;

(B) Process cash payments from participants and deposit proceeds into the Air Pollution Control Fund up to seven days after bidders are notified of results;

(C) Use the bid guarantee to cover payment for allowance purchases by any entity that fails to make cash payment within seven days after bidders are notified of results and place the proceeds into the Air Pollution Control Fund. If an entity has submitted more than one form of bid guarantee then the financial services administrator will apply the instruments to the unpaid balance in the order the instruments are listed in section 95913(fg)(2); and

(D) Return any unused bid guarantee.

(3) Upon determining that the financial services administrator has deposited the payment for allowances into the Greenhouse Gas Reduction Fund created pursuant to Government Code 16428.8~~Air Pollution Control Fund~~, the Executive Officer shall transfer the ~~serial numbers of the~~ allowances purchased from the Allowance Price Containment Reserve sale~~Account~~ into each winning bidder's compliance account.

(4) The Executive Officer shall inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances sold; and

(5) The Executive Officer shall publish the sale results at www.arb.ca.gov.

(ij) Entities registered in an External GHG ETS to which California has linked pursuant to subarticle 12 are not eligible to purchase from the Reserve.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95914. Auction Participation and Limitations.

(a) The Executive Officer may cancel or restrict a previously approved auction participation application or reject a new application if the Executive Officer determines that an entity has:

(1) Provided false or misleading facts;

(2) Withheld material information ~~for~~from its application or account application information listed in section 95830, with material meaning information that could ~~probably~~ influence a decision by the Executive Officer, the Board, or the Board's staff;

(3) Violated any part of the auction rules pursuant to subarticle 10;

(4) Violated the registration requirements pursuant to subarticle 5; or

(5) Violated the rules governing trading pursuant to subarticle 11.

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(c) Non-disclosure of Bidding Information ~~Among Auction Participants~~.

(1) Except as provided in section 95914(c)(2), all entities registered into the Cap-and-Trade program pursuant to section 95830 shall not release any of the following information regarding auction participation: ~~Unless it is to an auction advisor or other members of a direct corporate association not subject to auction participation restriction or cancellation pursuant to section 95914(b), an entity approved for auction participation shall not release any confidential information related to its auction participation, including:~~

(A) Intent to participate at auction, auction approval status, maintenance of continued auction approval; ~~Qualification status;~~

(B) Bidding strategy;

(C) Bid price or bid quantity information; and

(D) Information on the bid guarantee it provided to the financial services administrator. ; and

~~(E) Other information identified as confidential information in the auction application by the auction administrator.~~

(2) Auction participation information listed in section 95914(c)(1) may be released 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.

(3)~~(2)~~ If an entity participating in an auction has retained the services of an advisor regarding auction bidding strategy, then:

(A) The entity must ensure against the advisor transferring information to other auction participants or coordinating the bidding strategy among participants;

(B) The entity will inform the advisor of the prohibition of sharing information to other auction participants and ensure the advisor

has read and acknowledged the prohibition under penalty of perjury; ~~and~~

(C) 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 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; and
3. Assurance under penalty of perjury that advisor is not transferring to or otherwise sharing information with other auction participants.

(d) Application of the Corporate Association to the Auction Purchase Limit.

(1) The total number of compliance instruments which may be purchased in a single auction by a group of entities with a direct corporate association is limited pursuant to section 95911(d).

(2) Entities that are part of a direct corporate association ~~may~~must allocate shares of the purchase limit amongst themselves. This allocation of shares of the purchase limit must be provided pursuant to section 95830. Each entity will then have a specified percentage share of the association's purchase limit. The sum of the shares allocated among the entities must sum to one. Each associated entity's allocated purchase limit share times the auction purchase limit assigned to the association becomes the purchase limit for that entity.

(3) If a corporate association consists of entities with a compliance obligation and ~~voluntarilty~~voluntarily associated entities, then the following additional restrictions apply:

(A) The total purchase limit for the association is 15 percent, unless some of the included covered entities are electrical distribution utilities, in which case the purchase limit is 40 percent.

(B) The total purchase limit assigned to voluntarily associated entities within the corporate association must be less than or equal to 4 percent.

(C) The purchase limit to be divided among the covered or opt-in entities is the purchase limit assigned to the corporate association less the value assigned to the voluntarily associated entities within the corporate association.

~~(4) The group of associated entities must inform the Executive Officer when submitting the auction participant application of an allocation of the purchase limit among the associated entities, if applicable.~~

~~(5) The purchase limit allocation will be in effect for the auction for which the associated entities submitted the application.~~

~~(6) If entities with a direct corporate association do not allocate shares of the purchase limit among themselves, then the auction administrator will apply the purchase limit to the entities as follows:~~

~~(A) The administrator will order the associated entities' bids from highest to lowest bid price;~~

~~(B) Working from the highest to the lowest bid, the auction administrator will accept bids until the purchase limit for the associated entities is met;~~

~~(C) The auction operator will conduct this procedure before conducting the auction pursuant to section 95911.~~

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 11: Trading and Banking

§ 95920. Trading.

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(b) Application of the Holding Limit.

(1) The holding limit will apply to each entity registered as a covered, opt-in covered, or voluntarily associated entity pursuant to section 95830.

(2) The holding limit calculation will not include allowances contained in limited use holding accounts created pursuant to section 95831.

(3) Application of the Holding Limit to Exchange Clearing Holding Accounts. Compliance instruments transferred out of an exchange clearing holding account will count against the holding limit of the destination account listed in the transfer request submitted by an exchange clearing holding account at the time the transfer request is confirmed.

(4) If the Executive Officer determines that a reported transfer request not yet recorded into the tracking system would result in an entity's holdings exceeding the applicable holding limit, then the Executive Officer shall not approve the transfer request pursuant to section 95921(a)(1).

(5) If the violation is not discovered until after a transfer request is recorded, or the holding limit is exceeded at the beginning of a compliance year when allowances purchased at Advance Auction now fall under the current vintage holding limit pursuant to section 95920(c)(1)(C), then:

(A) The accounts administrator will inform the violator; and

(B) The violator will have five business days to bring its account balances within the holding limit. After that, the Executive Officer may transfer allowances in excess of the holding limit to the Auction Holding Account for consignment to auction pursuant to section 95910(d).

(C) Allowances transferred to the Auction Holding Account for consignment will be drawn first from the entity's Holding Account and, if necessary, from the entity's Compliance Account.

(6) Penalties may be applied whenever the holding limit is exceeded or transfer requests are filed with the accounts administrator that would violate the holding limit.

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(d) The holding limit will be calculated for allowances qualifying pursuant to section 95920€(1) as the sum of:

(1) The number given by the following formula:

Holding Limit = 0.1*Base + 0.025*(Annual Allowance Budget – Base)

In which:
"Base" equals 25 million metric tons of CO_2e.
"Annual Allowance Budget" is the number of allowances issued for the current budget year.

(2) Limited Exemption from the Holding Limit. ~~A Limited Exemption from the Holding Limit is calculated as:~~

(A) The limited exemption from the holding limit (limited exemption) is the maximum number of allowances which can be held in an entity's compliance account that will not be included in ~~are exempt from~~ 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. ~~Calculation after they are transferred by a covered entity or an opt-in covered entity to its compliance account.~~

(B) 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). ~~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.~~

(C) On January 1, 2015 the limited exemption will be increased by the amount of emissions that generate a compliance obligation pursuant to section 95851(b) that are included in the emissions data report received during 2014. ~~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~~.

(D) Beginning in 2015, the limited exemption will be increased on November 2 of each year by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verification statement during that year for emissions that generate a compliance obligation pursuant to sections 95851(a) and (b). ~~If for any year ARB has assigned emissions to an entity in the absence of a positive or qualified positive emissions data verification statement the calculation of the limited exemption will use the assigned emissions~~.

(E) If ARB has assigned emissions to an entity, for any year, in the absence of a positive or qualified positive emissions data verification statement the calculation of the limited exemption will be calculated using the assigned emissions. ~~For the first~~

~~compliance period all reported emissions or assigned emissions used to calculate the limited exemption will include only the emissions associated with the scope for the program during the first compliance period~~.

~~(F) Beginning in 2015, all reported emissions or assigned emissions used to calculate the limited exemption will include the emissions associated with the change in scope taking place in 2015.~~

~~(G) On January 1, 2015 the limited exemption will be increased by the amount of emissions included in the emissions data report received during 2014 but not yet included in the limited exemption pursuant to section 95920(d)(2)€.~~

(F)~~(H)~~ 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.

(G) Allowances allocated pursuant to section 95870(d) and €, which are transferred to the receiving entity's Limited Exemption Holding Account in a year preceding their vintage year, will not count against the Holding Limit or limited exemption until January 1 of their vintage year.

(3) Petition to Adjust the Limited Exemption.

(A) Prior to October 1 of any year, a covered entity may submit to the Executive Officer evidence demonstrating an increase in emissions for that year over the previous year and request a temporary increase in the limited exemption until verified data for that year are available.

(B) The amount of the increase must be at least 250,000 metric tons CO_2e on an annualized basis.

(C) The Executive Officer will review the evidence and determine whether an adjustment is needed.

(D) If an adjustment is granted, then the limited exemption for that covered entity will be increased immediately by the amount determined by the Executive officer.

(E) When the verified emissions data are received for the year for which an adjustment was granted, the Executive Officer will use the verified emissions value when calculating the limited exemption.

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(g) The holding limit in section 95920(a) shall include holdings of any allowances issued by a jurisdiction operating an External GHG ETS to which California has linked pursuant to ~~subartcle~~ subarticle 12.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95921. Conduct of Trade.

(a) Transfers of Compliance Instruments Between Accounts.

(1) Except when a transfer is undertaken by the Executive Officer, the accounts administrator will not register a transfer of compliance instruments between accounts into the tracking system until the administrator receives a transfer request that the Executive Officer has determined meets the requirements of this article.

(A) To initiate the process, the primary account representative or an alternate account representative of the source account for the transfer must submit a transfer request to the accounts administrator.

(B) The primary account representative or another alternate account representative for the same entity must confirm the transfer request to the accounts ~~admininstrator~~ administrator within two days of the initial submission of the transfer request.

(C) The primary account representative or an alternate account representative for the destination account must confirm the transfer request to the accounts administrator within the time remaining in the three days following the initial submission of the transfer request in section 95921(a)(1)(A).

(D) The Executive Officer must determine whether the transfer request and the transaction for which the transfer request was submitted meet the requirements of this article based on the information available at the time of approval.

(E) 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.

(2) The following transfers do not require confirmation by an account representative of the destination account pursuant to section 95921(a)(1)(C).

(A) Transfers initiated by the Executive Officer.

(B) Transfers between a single entity's holding and compliance accounts.

(3) The parties to a transfer will be in violation and penalties may apply if the above process is 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 ~~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

(D) More than three days after the execution of the underlying trade on an exchange or other trading platform.

(4) An entity may not submit a transfer request to another registered entity without an existing transaction agreement with that party authorizing a transfer.

(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:

(1) The following information must be entered into the tracking system for all transfer requests:

(A) Holding account number of the source account and identification of two individuals who are the primary account representative and/or alternate account representatives initiating the transfer request.

(B) Account number of destination account and identification of a primary account representative or alternate account representative for the destination account confirming the transfer request, if confirmation of the transfer request is required.

(C) Type, quantity, and vintage of compliance instrument.

(2) The transfer request must identify the type of transaction agreement for which the transfer request is being submitted, selecting one of the following three types:

(A) Over-the-counter agreement for the sale of compliance instruments for which delivery will take place no more than three days from the date the parties enter into the transaction agreement.

(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 for the bundled sale of compliance instruments with other products.

(C) Exchange-based agreements for the sale of compliance instruments through any contract arranged through an exchange or Board of Trade.

(3) A transfer request submitted for an over-the-counter agreement for the sale of compliance instruments for which delivery will take place no more than three days from the date the parties enter into the transaction agreement must provide the following information:

(A) Date the entity entered into the transaction agreement.

(B) Date of settlement. If completion of the transfer request process is the last step of the agreement, the date the transfer request is submitted should be entered as the settlement date. 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.

(C) Price of the compliance instrument in U.S. dollars or Canadian dollars.

(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:

(A) Date the entity entered into the transaction agreement.

(B) Date the transaction agreement terminates.

(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.

(D) If the transaction agreement provides for transfers of other products, identify the products specified in the agreement.

(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.

(5) A transfer request submitted for an Exchange-Based Agreement must provide the following information:

(A) Identify the exchange where the transaction is conducted.

(B) Identify the exchange code for the contract.

(C) Identify the contract as spot or futures.

(D) Date of close of trading for the contract.

(E) Price at close of trading for the contract.

(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.

(A) The proposed transfer is between entities with a direct corporate association.

(B) The proposed transfer is from an entity's holding account to its compliance account.

(C) 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.

(D) The proposed transfer is from a public utility to a federal power authority to cover emissions associated with imported power.

(E) The proposed transfer is from an electric distribution utility to an entity operating a generation facility under a tolling agreement or other long-term power purchase agreement that does not specify a price or cost basis for the sale of the compliance instruments alone.

(F) The proposed transfer results from a transaction agreement that bundles compliance instruments with other products and does not specify a price or cost basis for the sale of the compliance instruments alone.

~~(1) Holding account number of the source account and identification of two individuals who are the primary account representative and/or alternate account representatives initiating the transfer request;~~

~~(2) Holding account number of destination account and identification of a primary account representative or alternate account representative for the destination account confirming the transfer request;~~

~~(3) Serial numbers of the compliance instruments;~~

~~(4) Date of the transaction agreement for which the transfer request is submitted;~~

~~(5) Actual or expected settlement date, if not the same as date of the transaction agreement;~~

~~(6) Price of the compliance instrument in U.S. dollars. Disclosure of price is not required for transfers between entities with a direct corporate association or from an entity's holding account to its compliance account.~~

~~(7) If California links to Canadian jurisdictions pursuant to subarticle 12, the price of the compliance instrument may be reported in Canadian dollars in section 95921(b)(6).~~

(c) Transfer Request Deficiencies

(1) If the accounts administrator detects a deficiency in a transfer request before it is recorded into the tracking system:

(A) The accounts administrator will inform the entities submitting the request that the transfer request is deficient and inform the Executive Officer of the deficiency;

(B) The accounts administrator will inform the entity responsible for the deficiency of the specific problem to be remedied.

(C) ~~(B)~~ The entities submitting the transfer request may resubmit the request with the deficiency corrected within the time limit set pursuant to sections 95921(a)(1)(C) and €; and

(D) ~~(C)~~ If the entities fail to submit an acceptable transfer request within the time limit, then they must either withdraw the transfer request or submit a new transfer request. Penalties may still apply pursuant to section 95921(a)(3).

(2) If the accounts administrator detects a deficiency in a transfer request after it is recorded into the tracking system:

(A) The accounts administrator will inform the entities submitting the request that the transfer request is deficient and inform the Executive Officer of the deficiency; ~~and~~

(B) If the deficiency is based on the information submitted by the representative of the source account, the Executive Officer will inform the submitting representative of the specific deficiency;

(C) If the deficiency is a violation of the holding limit, the Executive Officer will inform the primary account representative for the account listed on the transfer request as the destination account of the deficiency; and

(D) ~~(B)~~ If the entities that submitted the transfer request cannot correct the deficiency within five business days after notification by the accounts administrator, the Executive Officer may instruct the accounts administrator to reverse the transfer.

(d) Transfers Involving Exchange Clearing Holding Accounts.

(1) A request to transfer compliance ~~instruements~~ instruments to an exchange clearing holding account will list the exchange clearing holding account as the destination account.

(2) All of the compliance instruments received by an exchange clearing holding account must be transferred to one or more destination accounts within five days of receiving them.

(3) A request to transfer compliance instruments to or from an exchange clearing holding account does not require confirmation by an account representative of the destination account pursuant to section 95921(a)(1)(C).

(4) A request to transfer compliance instruments from an exchange clearing holding account does not require confirmation by a second account.

(e) Protection of Confidential Information. The Executive Officer will protect confidential information to the extent permitted by law by ensuring that the accounts administrator:

(1) Releases information on the transfer price and quantity of compliance instruments in a manner that is timely and maintains the confidentiality of the parties to a transfer;

(2) Except as needed for market oversight and investigation by the Executive Officer, protects as confidential all other information obtained through transfer requests;

(3) Protects as confidential the quantity and serial numbers of compliance instruments contained in holding accounts; and

(4) Releases information on the quantity ~~and serial numbers~~ of compliance instruments contained in compliance accounts in a timely manner.

(f) General Prohibitions on Trading.

(1) An entity cannot acquire allowances and hold them in its own holding account on behalf of another entity~~.~~ 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) An entity may purchase and hold compliance instruments for later transfer to members of a direct corporate association.

(2) A trade involving, related to, or associated with any of the following are prohibited:

(A) Any manipulative or deceptive device in violation of this article;

(B) A corner or an attempt to corner the market for a compliance instrument;

(C) Fraud, or an attempt to defraud any other entity;

(D) A false, misleading or inaccurate report concerning information or conditions that affects or tends to affect the price of a compliance instrument;

(E) An application, report, statement, or document required to be filed pursuant to this article which is false or misleading with respect to a material fact, or which omits to state a material fact necessary to make the contents therein not misleading; or

(F) Any trick, scheme, or artifice to falsify or conceal a material fact, including use of any false statements or representations, written or oral, or documents made by or provided to an entity on or through which transactions in compliance instruments occur, are settled, or are cleared.

(G) A fact is material if it could probably influence a decision by the Executive Officer, the Board, or the Board's staff.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95922. Banking, Expiration, and Voluntary Retirement.

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(d) Voluntary Retirement of Compliance Instruments.

(1) An entity registered pursuant to section 95830 may voluntarily submit any compliance instrument for retirement.

(2) To voluntarily retire a compliance instrument, the registered entity submits a transaction report to the accounts administrator listing its account number, the type and ~~serial~~ numbers of ~~the~~ instruments to be retired, and the ARB Retirement Account as the destination account.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95923. Disclosure of Cap-and-Trade Consultants and Advisors.

(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, 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 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):

(1) Information to identify the Cap-and-Trade 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 Consultants or Advisors.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 12: Linkage to External Greenhouse Gas Emissions Trading Systems

§ 95942. Interchange of Compliance Instruments with Linked External Greenhouse Gas Emissions Trading Systems.

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(f) The administrator of the approved External GHG ETS must agree to inform the Executive Officer of any of the serial numbers of California compliance instruments that the External GHG ETS accepts for compliance.

(g) The Executive Officer will agree to inform the appropriate official in the approved External GHG ETS of any of the serial numbers of compliance instruments accepted by California for compliance.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 13: ARB Offset Credits and Registry Offset Credits

§ 95970. General Requirements for ARB Offset Credits and Registry Offset Credits.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95971. Procedures for Approval of Compliance Offset Protocols.

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(b) All Compliance Offset Protocols shall be reviewed and periodically revised, if needed, ~~and~~ in compliance with the California Administrative Procedure Act, if applicable.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95972. Requirements for Compliance Offset Protocols.

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(c) Geographic Applicability. A Compliance Offset Protocol must specify where the protocol is applicable. The geographic boundary must be within the United States ~~or its~~, United States Territories, Canada, or Mexico.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95973. Requirements for Offset Projects Using ARB Compliance Offset Protocols.

(a) General Requirements for Offset Projects. To qualify under the provisions set forth in this article, an Offset Project Operator or Authorized Project Designee must ensure that an offset project:

(1) Meets all of the requirements in a Compliance Offset Protocol approved by the Board pursuant to section 95971;

(2) Meets the following additionality requirements, as well as any additionality requirements in the applicable Compliance Offset Protocol, as of the date of Offset Project Commencement:

(A) The activities that result in GHG reductions and GHG removal enhancements are not required by law, regulation, or any legally binding mandate applicable in the offset project's jurisdiction, and would not otherwise occur in a conservative business-as-usual scenario;

(B) The Offset Project Commencement date occurs after December 31, 2006, unless otherwise specified in the applicable Compliance Offset Protocol, except as provided in section 95973(c); and

(C) The GHG reductions and GHG removal enhancements resulting from the offset project exceed the project baseline calculated by the Compliance Offset Protocol for that offset project type as set forth in the following:

1. Compliance Offset Protocol Ozone Depleting Substances Projects, incorporated by reference October 20, 2011;
2. Compliance Offset Protocol Livestock Projects, incorporated by reference October 20, 2011;
3. Compliance Offset Protocol Urban Forest Projects, incorporated by reference October 20, 2011; ~~and~~
4. Compliance Offset Protocol U.S. Forest Projects, incorporated by reference October 20, 2011~~.~~; and

5. Compliance Offset Protocol Mine Methane Capture Projects, incorporated by reference [DATE].

(3) Is located in the United States ~~or its~~, United States Territories, Canada, or Mexico.

(b) Local, Regional, and National Regulatory and Environmental Impact Assessment Requirements. An Offset Project Operator or Authorized Project Designee must fulfill all local, regional, and national requirements on environmental impact assessments that apply based on the offset project location. In addition, offset projects must also fulfill 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. Offset projects are 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.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95974. Authorized Project Designee.

(a) General Requirements for Designation of Authorized Project Designee. An Offset Project Operator may designate an entity as an Authorized Project Designee at the time of offset project listing or any time after offset project listing as long as it meets the requirements of section 95974(b). ~~The Offset Project Operator must identify to ARB or an Offset Project Registry the rights and responsibilities they are assigning or delegating to an Authorized Project Designee.~~

(1) The Offset Project Operator may assign ownership rights of ARB offset credits or registry offset credits to the following entities at the time of registry offset credit or ARB offset credit issuance pursuant to sections 95980.1 and 95981, respectively:

(A) Authorized Project Designee; or

(B) Any other third party not otherwise prohibited by this article.

(2) 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.

(A) If an Authorized Project Designee is designated, the Authorized Project Designee will be responsible for performing all activities to meet the requirements in the section 95974(a)(2) and will be the main point of contact with regard to the offset project for the Offset Project Registry and ARB. The Offset Project Operator, however, is ultimately responsible for ensuring compliance with the requirements of this article and the applicable Compliance Offset Protocol.

(B) If an Authorized Project Designee is designated, the Offset Project Operator must designate an individual of the Authorized Project Designee as a Primary Account Representative or Alternate Account Representative on the Offset Project Operator's tracking system account before the Authorized Project Designee may act on behalf of the Offset Project Operator or submit any documentation to the Offset Project Registry and ARB. Only an individual authorized on the Offset Project Operator's tracking system account may sign any

documents or attestations to ARB on behalf of the Offset Project Operator for an offset project.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95975. Listing of Offset Projects Using ARB Compliance Offset Protocols.

(a) General Requirements for Offset Project Operators or Authorized Project Designees Who Are Submitting an Offset Project for Listing. Before an offset project can be listed by ARB or an Offset Project Registry the Offset Project Operator~~,~~ and its Authorized Project Designee ~~and~~, if applicable, ~~another third-party as provided in section 95974(a)(1)~~ must:

(1) Register with ARB pursuant to section 95830; and

(2) Not be subject to any Holding Account restrictions imposed pursuant to section 96011.

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(c) General Requirements for Offset Project Listing. For offset projects being listed by ARB or an Offset Project Registry in an initial or renewed crediting period, the Offset Project Operator and any Authorized Project Designees approved pursuant to section 95974 must:

(1) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California the GHG reductions and/or GHG removal enhancements for [project] from [date] to [date] will be measured in accordance with the [appropriate ARB Compliance Offset Protocol] and all information required to be submitted to ARB is true, accurate, and complete~~;~~.";

(2) Attest, in writing, to ARB as follows:

"I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes arising from the enforcement of provisions in this article.";

(3) Attest in writing to ARB as follows:
"I understand that the offset project activity and implementation of the offset project must be in accordance with all applicable local, regional, and national environmental and health and safety laws and regulations that apply to the offset project location. I understand that offset projects are not eligible to receive ARB or registry offset credits for GHG reductions and GHG removal enhancements that are not in compliance with the requirements of the cap-and-trade program.";

(4) Provide all documentation required pursuant to section 95975(e) to ARB or an Offset Project Registry; and

(5) Disclose GHG reductions and GHG removal enhancements issued credit by any voluntary or mandatory programs for the same offset project being listed or any GHG reductions and GHG removal enhancements used for any GHG mitigation requirement.

(d) The attestations in section 95975(c)(1), 95975(c)(2), and 95975(c)(3) ~~may~~ must be provided to an Offset Project Registry with the listing information, if being listed with an Offset Project Registry, or to ARB if being listed with ARB ~~but must be provided to ARB when the requirements in section 95981(b) apply~~.

(e) Offset Project Listing Information Requirements. Before an offset project is publicly listed for an initial or renewed crediting period the Offset Project Operator or Authorized Project Designee must provide the listing information in a Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011;

(2) Compliance Offset Protocol Livestock Projects, October 20, 2011;

(3) Compliance Offset Protocol Urban Forest Projects, October 20, 2011; ~~and~~

(4) Compliance Offset Protocol U.S. Forest Projects, October 20, 2011~~.~~; and

(5) Compliance Offset Protocol Mine Methane Capture Projects, [DATE].

(f) Review of Offset Project Listing Information. ARB or the Offset Project Registry will review the offset project listing information submitted pursuant to section 95975(e) for completeness.

(~~f~~g) Notice of Completeness for Offset Project Listing Information. The Offset Project Operator or Authorized Project Designee will be notified after review by ARB or the Offset Project Registry, if the information submitted pursuant to section 95975(e) is complete and may be listed. If ~~it is~~ARB or the Offset Project Registry determined that the information submitted pursuant to section 95975(e) is incomplete or that a denial of the listing information is required, ARB or the Offset Project Registry will notify the Offset Project Operator or Authorized Project Designee of this determination~~will be notified~~ within 30 calendar days ~~by ARB or an Offset Project Registry~~of receiving the listing information from the Offset Project Operator or Authorized Project Designee.

(~~g~~h) Timing for Offset Project Listing in an Initial Crediting Period. The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(e) to ARB or an Offset Project Registry no later than the date at which the Offset Project Operator or Authorized Project Designee submits its required Offset Project Data Report for its initial Reporting Period under a Compliance Offset Protocol to ARB or an Offset Project Registry pursuant to section 95976. For offset projects with an Offset Project Commencement date on or after January 1, 2015, the Offset Project Operator or Authorized Project Designee must submit the

listing information in section 95975(e) to ARB or an Offset Project Registry within one year of Offset Project Commencement, or within one year of meeting the requirements of section 95975(l), whichever is later. If, after January 1, 2015, the Offset Project Operator or Authorized Project Designee does not submit the listing information in section 95975(e) for the offset project to ARB or an Offset Project Registry within one year of Offset Project Commencement, or within one year of meeting the requirements of section 95975(l), whichever is later, it will be ineligible to be listed under a Compliance Offset Protocol and will not be issued registry offset credits and ARB offset credits pursuant to sections 95980 and 95981.

(~~h~~i) Listing Status of Offset Projects in an Initial Crediting Period. After the Offset Project Operator or Authorized Project Designee submits the offset project for listing in an initial crediting period and the required documentation pursuant to section 95975(e), and ARB or the Offset Project Registry has reviewed the offset project listing information for completeness~~against the additionality requirements in section 95973(a)(2)~~, the offset project listing status will be "Proposed Project." If the offset project is not accepted for listing by an Offset Project Registry, the Offset Project Operator or Authorized Project Designee may request ARB to make a final determination if the offset project meets the requirements in section 95975 to be listed for an initial crediting period by the Offset Project Registry. In making this determination, ARB may consult with the Offset Project Registry before making the final determination.

(ij) Timing for Offset Project Listing in a Renewed Crediting Period. The Offset Project Operator or Authorized Project Designee must submit the information in section 95975(e) for a renewed crediting period to ARB or an Offset Project Registry no earlier than 18 months and no later than 9 months before conclusion of the initial crediting period or a previous renewed crediting period.

(jk) Listing Status of Offset Projects in a Renewed Crediting Period. After the Offset Project Operator or Authorized Project Designee submits the offset project for listing in a renewed crediting period and the required documentation pursuant to section 95975(e), and ARB or the Offset Project Registry has reviewed the offset project listing information for completenessagainst the additionality requirements in section 95973(a)(2)(A) and 95973(a)(2)(C) as of the date of the commencement of the renewed crediting period, the offset project listing status will be "Proposed Renewal." If the offset project is not accepted for listing by an Offset Project Registry, the Offset Project Operator or Authorized Project Designee may request ARB to make a final determination if the project meets the requirements in section 95975 to be listed for a renewed crediting period by the Offset Project Registry. In making this determination, ARB may consult with the Offset Project Registry before making the final determination.

(l) Additional Offset Project Listing Requirements for Tribes. In addition to meeting the listing requirements in sections 95975(c)(1) through (5), Tribes must meet the following requirements before offset projects located on the categories of land specified in section 95973(d) can be listed with ARB or an Offset Project Registry pursuant to this section. The requirements of this article apply regardless of the category of land on which the offset project is located.

(1) The governing body of the Tribe must enter into a limited waiver of sovereign immunity with ARB related to its participation in the requirements of the Cap-and-Trade Program for the duration required by the applicable Compliance Offset Protocol(s). This waiver must include a consent to suit by the State of California, Air Resources Board, in the courts of the State of California, with respect to any action in law or equity commenced by the State of California, Air Resources Board to enforce the obligations of the Tribe with respect to its participation in the Cap-and-Trade Program, irrespective of the form

of relief sought, whether monetary or otherwise, except for purposes of relief under this limited waiver, Tribes shall be treated in the same manner as a California public entity under California Government Code sections 818 and 818.8.

(2) The Tribe must provide ARB with documentation demonstrating that the limited waiver of sovereign immunity entered into pursuant to section 95975(l)(1) has been properly adopted in accordance with the Tribe's Constitution or other organic law, by-laws and ordinances, and applicable federal laws.

(3) For offset projects located on Indian lands, as defined in 25 U.S.C. §81(a)(1), the Tribe must also provide ARB with proof of federal approval of the Tribe's participation in the requirements of the Cap-and-Trade Program, or documentation from the U.S. Department of the Interior, Bureau of Indian Affairs that federal approval is not required.

(m) Once ARB or an Offset Project Registry approves an offset project for listing, the listing information is considered final, and cannot be changed unless the Offset Project Operator changes during the crediting period.

(1) If the Offset Project Operator changes during the crediting period the new Offset Project Operator or Authorized Project Designee must submit updated listing information for the information that pertains to the Offset Project Operator and Authorized Project Designee, if applicable, to ARB or OPR within 30 calendar days of the change.

(2) If the Offset Project Operator changes during the crediting period the new Offset Project Operator or Authorized Project Designee must submit the information required pursuant to section 95975(c) to ARB OPR within 30 calendar days of the change.

(k~~n~~) Limitations for Crediting Period Renewals. A crediting period may be renewed if the offset project meets the requirements for additionality pursuant to section ~~95975(j)~~95973(a)(2) and in the applicable Compliance Offset Protocol.

(1) The crediting period for non-sequestration offset projects may be renewed twice for the length of time identified by the Compliance Offset Protocol.

(2) Sequestration offset projects are not subject to any renewal limits.

(o) Transferring an Offset Project to Another Offset Project Registry. If the Offset Project Operator or Authorized Project Designee transfers an offset project listed with an Offset Project Registry to another Offset Project Registry:

(1) The Offset Project Registry that originally listed the offset project must change the offset project listing status on its registry system to "Transferred ARB Project."

(A) If the only action taken by the Offset Project Operator or the Authorized Project Designee was to submit the listing documentation for the offset project, the original Offset Project Registry must retain the information related to the offset project on its website for the duration of one year before it is removed from the registry system.

(B) If a verification body submitted an Offset Verification Statement, the original Offset Project Registry must retain the information related to the offset project on its website for the duration of the offset project life.

(C) The new Offset Project Registry must retain the listing date and all listing information as approved by the original Offset Project Registry. If the offset project has not undergone initial verification, the Offset Project Commencement date may change as a result of verification activities only.

(2) The Offset Project Operator or Authorized Project Designee must submit the original listing documentation reviewed and accepted by the original Offset Project Registry pursuant to this section to the new Offset Project Registry. The Offset Project Operator or Authorized

Project Designee may only make changes to the listing documentation pursuant to section 95975(m).

(3) The Offset Project Operator or Authorized Project Designee may not transfer an offset project to another Offset Project Registry once a Notice of Offset Verification Services has been submitted pursuant to section 95977.1(b)(1) or during the course of offset verification services. Once a Notice of Offset Verification Services has been submitted, the offset verification services must be completed for the applicable Reporting Period before the Offset Project Operator or Authorized Project Designee may transfer the offset project to another Offset Project Registry.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95976. Monitoring, Reporting, and Record Retention Requirements for Offset Projects.

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(c) An Offset Project Operator or Authorized Project Designee must put in place all monitoring equipment or mechanisms required by a Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011;

(2) Compliance Offset Protocol Livestock Projects, October 20, 2011;

(3) Compliance Offset Protocol Urban Forest Projects, October 20, 2011; ~~and~~

(4) Compliance Offset Protocol U.S. Forest Projects, October 20, 2011; and

(5) Compliance Offset Protocol Mine Methane Capture Projects, [DATE].

(d) Offset Project Reporting Requirements. An Offset Project Operator or Authorized Project Designee shall submit an Offset Project Data Report to ARB or an Offset Project Registry ~~annually~~ for each Reporting Period as

defined in section 95802. Each Offset Project Data Report must cover a single Reporting Period. Reporting Periods must be contiguous; there must be no gaps in reporting once the first Reporting Period has commenced. For projects developed under the Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011 there may be one Offset Project Data Report submitted for each offset project and the Offset Project Data Report may cover up to a maximum of 12 months of data. The Offset Project Operator or Authorized Project Designee must submit an Offset Project Data Report to ARB or an Offset Project Registry within 24 months of listing their offset project pursuant to section 95975. The Offset Project Data Report shall contain the information required by a Compliance Offset Protocol for that offset project type as set forth in:

(1) Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011;

(2) Compliance Offset Protocol Livestock Projects, October 20, 2011;

(3) Compliance Offset Protocol Urban Forest Projects, October 20, 2011; ~~and~~

(4) Compliance Offset Protocol U.S. Forest Projects, October 20, 2011~~.~~; and

(5) Compliance Offset Protocol Mine Methane Capture Projects, [DATE].

(~~5~~6) The Offset Project Operator or Authorized Project Designee must attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California the GHG reductions and/or GHG removal enhancements for [project] from [date] to [date] are measured in accordance with the [appropriate ARB Compliance Offset ~~approved p~~Protocol] and all information required to be submitted to ARB in the Offset Project Data Report is true, accurate, and complete."

This attestation ~~may~~must be provided to an Offset Project Registry with the Offset Project Data Report if the offset project is listed with an

Offset Project Registry, or to ARB if the offset project is listed with ARB ~~but must be provided to ARB when the requirements in section 95981(b) apply~~.

(~~6~~7) All Offset Project Data Reports must be submitted within four months after the conclusion of each Reporting Period.

(~~7~~8) If an Offset Project Data Report is not submitted to ARB or an Offset Project Registry by the applicable reporting deadline, the GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report are not eligible to be issued ARB offset credits pursuant to section 95981.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95977. Verification of GHG Emission Reductions and GHG Removal Enhancements from Offset Projects.

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(b) Schedule for Verification of Non-Sequestration Offset Projects. The verification of GHG emission reductions for non-sequestration offset projects that produce greater than or equal to 25,000 metric tons of GHG reductions must be performed ~~annually~~ on a 12-month rolling basis and cover the Reporting Period for which the most recent Offset Project Data Report was submitted. For Reporting Periods in which an Offset Project Data Report for a non-sequestration offset project shows that the offset project produced fewer than 25,000 metric tons of GHG reductions, the Offset Project Operator or Authorized Project Designee may choose to perform verification that covers two consecutive Reporting Periods, even if for the subsequent Reporting Period the offset project produced greater than or equal to 25,000 metric tons of GHG reductions. If an Offset

Project Data Report results in zero GHG emission reductions, the Offset Project Operator or Authorized Project Designee may defer verification until the offset project produces an Offset Project Data Report that no longer results in zero GHG emission reductions.

(c) Schedule for Verification of Sequestration Offset Projects. ~~The~~An initial verification of GHG emission reductions and GHG removal enhancements for all sequestration offset projects must be performed following the first Reporting Period and cover one Reporting Period. After the first Reporting Period, verification must be conducted at least once every six years and may cover up to six Reporting Periods for which Offset Project Data Reports were submitted. After an initial verification with a Positive Offset Verification Statement, reforestation offset projects and urban forest offset projects that meet the requirements of the applicable Compliance Offset Protocol may defer the second verification for twelve years, but verification of Offset Project Data Reports must be performed at least once every six years thereafter.

(d) Timing for Submittal of Offset Verification Statements to ARB or an Offset Project Registry. Any Offset Verification Statement must be received by ARB or an Offset Project Registry within ~~nine~~eleven months after the conclusion of the Reporting Period for which offset verification services were performed. If the Offset Verification Statement is not submitted to ARB or an Offset Project Registry by the verification deadline, the GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report are not eligible to be issued ARB offset credits or registry offset credits. The verification body must issue one Offset Verification Statement for each Offset Project Data Report that it verifies for the Offset Project Operator or Authorized Project Designee.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95977.1. Requirements for Offset Verification Services.

(a) Rotation of Verification Bodies. An offset project shall not have more than six consecutive ~~years of offset project data~~Reporting Periods verified by the same verification body or verifier(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 previous verification body or verifier(s) only if at least three ~~years of the offset project data~~consecutive Reporting Periods have been verified by a different verification body or verifier(s) before the previous verification body is selected again, unless otherwise specified in section 95977.1(a)(1) or (a)(2). The ~~six year~~ rotation requirements in this section are~~is~~ applied between the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and the verification body ~~or~~and verifier(s) on an offset project basis.

(1) For offset projects developed under the Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011, the following shall apply: An Offset Project Operator or Authorized Project Designee shall not have more than six offset projects verified by the same verification body and verifier(s). An Offset Project Operator or Authorized Project Designee may contract with a previous verification body and verifier(s) only if at least three consecutive offset projects have been verified by a different verification body or verifier(s) before the previous verification body is selected again.

(2) For reforestation offset projects developed under, and meeting the requirements of, the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, and urban forest offset projects developed under, and that meet the requirements of, the Compliance Offset Protocol Urban Forest Projects, October 20, 2011, the following shall apply: An Offset Project Operator or Authorized Project Designee that has deferred the second verification for 12 years may have up to 13 Offset Project Data Reports verified by the same verification body and verifier(s). If an Offset Project Operator or Authorized Project

Designee has not deferred the second verification to 12 years, the requirements in section 95977.1(a) for rotation of verification bodies and verifier(s) shall apply. An Offset Project Operator or Authorized Project Designee may contract with a previous verification body and verifier(s) only if at least three consecutive Offset Project Data Reports have been verified by a different verification body or verifier(s) before the previous verification body is selected again.

(b) Offset Verification Services. Offset Verification Services shall be subject to the following requirements.

(1) Notice of Offset Verification Services for Offset Projects. Before offset verification services, as defined in section 95977.1(b)(3), may begin, the verification body must submit a Notice of Offset Verification Services to ARB and an Offset Project Registry, if applicable. The verification body may begin offset verification services for the Offset Project Operator or Authorized Project Designee ~~10 working~~30 calendar days after the Notice for Offset Verification Services is received by ARB ~~or~~and the Offset Project Registry, or earlier, if approved by ARB in writing. The Notice ~~for~~of Offset Verification Services must include the following information:

(A) The name of the offset project type, including the length of the offset project crediting period, and title of the Compliance Offset Protocol used to implement the offset project;

(B) A list of staff who will be designated to provide offset verification services as part of an offset verification team, including the names of each designated staff member, the lead verifier, independent reviewer, all subcontractors, and a description of the roles and responsibilities each team member will have during the offset verification process;

(C) Documentation that the offset verification team has the skills required to provide offset verification services for the Offset Project Operator or Authorized Project Designee. At least one

offset verification team member must be accredited by ARB as an offset project specific verifier for an offset project of that type; and

(D) General information on the Offset Project Operator or Authorized Project Designee, including:

1. The name of the Offset Project Operator or Authorized Project Designee, including contact information, address, telephone number, and email address;
2. The locations that will be subject to offset verification services;
3. The date(s) of on-site visits, with address and contact information; and
4. A brief description of expected offset verification services to be performed, including expected completion date.

(2) If any information submitted pursuant to sections 95977.1(b)(1)(B) and 95977.1(b)(1)(D) changes after the Notice for Offset Verification Services is submitted to ARB and the Offset Project Registry, if applicable, and before offset verification services begin, the verification body must notify ARB and the Offset Project Registry by submitting an updated ~~conflict of interest self-evaluation form~~Notice of Offset Verification Services as soon as the change is made, but, at least five business days prior to the start of offset verification services, unless otherwise approved by ARB in writing. If any information submitted pursuant to sections 95977.1(b)(1)(B) and 95977.1(b)(1)(D) changes during offset verification services, the verification body must notify ARB and the Offset Project Registry, if applicable. In either instance, the ~~conflict of interest~~Notice of Offset Verification Services must be resubmitted to ARB and~~or~~ the Offset Project Registry, as applicable. If ARB and the Offset Project Registry, if applicable, request revisions to the Notice of Offset Verification Services, the verification body must

resubmit the revised Notice of Offset Verification Services within ten calendar days of such request.

(3) Offset verification services must include the following:

(A) Offset Verification Plan. The Offset Project Operator or Authorized Project Designee must submit the following information necessary to develop an Offset Verification Plan to the offset verification team:

1. Information to allow the offset verification team to develop a general understanding of offset project boundaries, operations, project baseline emissions, and annual GHG reductions and GHG removal enhancements;
2. Information regarding the training or qualifications of personnel involved in developing the Offset Project Data Report;
3. The name and date of the Compliance Offset Protocol used to quantify and report project baselines, GHG reductions, GHG removal enhancements, and other required data as applicable in the Compliance Offset Protocol; and
4. Information about any data management system, offset project monitoring system, and models used to track project baselines, GHG reductions, GHG removal enhancements, and other required data as applicable in the Compliance Offset Protocol.

(B) Timing of Offset Verification Services. The Offset Verification Plan~~Such information~~ shall also include the following information:

1. Dates of proposed meetings and interviews with personnel related to the offset project;
2. Dates of proposed site visits;
3. Types of proposed document and data reviews; and
4. Expected date for completing offset verification services.

(C) Planning Meetings with the Offset Project Operator or Authorized Project Designee. The offset verification team must discuss with the Offset Project Operator or Authorized Project Designee the scope of the offset verification services and request any information and documents needed for initial offset verification services. The offset verification team must review the documents submitted and plan and conduct a review of original documents and supporting data for the Offset Project Data Report. Any discussions or meetings to secure an offset verification services contract or collect preliminary project documents to bid the offset verification services may occur prior to submitting the Notice of Offset Verification Services pursuant to section 95977.1(b)(1).

(D) Site Visits for Offset Projects. For a non-sequestration offset project, at least one accredited offset verifier in the offset verification team, including the offset project specific verifier, must make at least one site visit ~~every year to~~ for each ~~offset project location for which an~~ Reporting Period that an Offset Project Data Report is submitted, except for those non-sequestration offset projects that qualify for a two-year offset verification period pursuant to section 95977(b). In this case, at least one offset verifier in the offset verification team, including the offset project specific verifier, must make a site visit ~~to each offset project location in the year that~~for the Reporting Period for which offset verification services are performed. For a forest or urban forest offset project, at least one accredited offset verifier in the offset verification team, including the offset project specific verifier, must make a site visit every year that offset verification services are provided, except for those offset projects approved for less intensive verification, for which a site visit must be performed at least once every six years. A site

visit is also required after the first ~~full calendar year of operations~~Reporting Period of an offset project under a Compliance Offset Protocol and after the first Reporting Period for each renewed crediting period under a Compliance Offset Protocol. The site visit required under this section must be performed after the Offset Project Operator or Authorized Project Designee submits its Offset Project Data Report to ARB or an Offset Project Registry. During the required site visit, the offset verification team member(s) must conduct the following:

1. During the initial site visit conducted following the first Reporting Period of the crediting period the offset verification team members must:
   a. Assess offset project eligibility and that the offset project meets the requirements for additionality according to section 95973 and the applicable Compliance Offset Protocol;
   b. Review the information submitted for listing pursuant to section 95975;
   c. Confirm that the offset project boundary is appropriately defined;
   d. Review project baseline calculations and modeling;
   e. Assess the operations, functionality, data control systems, and review GHG measurement and monitoring techniques; and
   f. Confirm that all applicable eligibility criteria to design, measure, establish the chain of custody, and monitor the offset project conforms to the requirements of the applicable Compliance Offset Protocol.
   g. All criteria pertaining to the eligibility of the offset project must be assessed during the first site visit in the initial Reporting Period. All eligibility criteria must

be met and are not subject to sampling. If any of the eligibility criteria are not met, the project would be ineligible for crediting and receive an Adverse Offset Verification Statement.

2. During the initial site visit conducted following the first Reporting Period of the crediting period and each subsequent site visit the offset verification team must:

   a. Check that all offset project boundaries, GHG emissions sources, GHG sinks, and GHG reservoirs in the applicable Compliance Offset Protocol are identified appropriately;

   b. Review and understand the data management systems used by the Offset Project Operator or Authorized Project Designee to track, quantify, and report GHG reductions, GHG removal enhancements, or other data required as applicable in the Compliance Offset Protocol. This includes reviewing data collection processes and procedures, sampling techniques and metering accuracy, quality assurance/quality control processes and procedures, and missing data procedures. The offset verification team member(s) must evaluate the uncertainty and effectiveness of these systems;

   c. Interview key personnel involved in collecting offset project data and preparing the Offset Project Data Report;

   d. Make direct observations of equipment for data sources and equipment supplying data for GHG emission sources in the sampling plan determined to be high risk;

e. Collect and review other information that, in the professional judgment of the team, is needed in the offset verification process;

f. Confirm the offset project conforms with all local, state, or federal environmental regulatory requirements pursuant to section 95973(b), including health and safety regulations; and

g. Review all chain of custody documents as required in the Compliance Offset Protocol, if applicable.

h. If the offset project is found by the offset verification team to not meet the requirements of section 95977.1(b)(3)(D)(2.)(f.), the offset project is ineligible to receive ARB offset credits or registry offset credits for GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report.

i. The activities performed pursuant to sections 95977.1(b)(3)(D)(2.)(f.) through (b)(3)(D)(2.)(h.) may be included in a site visit or, alternatively, may be conducted as part of a desk review.

(E) The offset verification team must review offset project operations to identify applicable GHG emissions sources, project emissions, GHG sinks, and GHG reservoirs required to be included and quantified in the Offset Project Data Report as required by the applicable Compliance Offset Protocol. This must include a review of each type of GHG emissions source, GHG sink, and GHG reservoir to ensure that all GHG emissions sources, GHG sinks, and GHG reservoirs required to be reported for the offset project are properly included in the Offset Project Data Report.

(F) An Offset Project Operator or Authorized Project Designee must make available to the offset verification team all information and documentation used to calculate and report project baseline and ~~annual~~project GHG emissions, GHG reductions, and GHG removal enhancements and other information required by the applicable Compliance Offset Protocol.

(G) Sampling Plan for Offset Project Data Reports. As part of confirming the Offset Project Data Report, the offset verification team must develop a sampling plan that meets the following requirements:

1. The offset verification team must develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale, and complexity of the offset verification services for an Offset Project Operator or Authorized Project Designee. The analysis must review the inputs for the development of the submitted Offset Project Data Report, the rigor and appropriateness of the GHG data management systems, and the coordination within an Offset Project Operator's or Authorized Project Designee's organization to manage the operation and maintenance of equipment and systems used to develop the Offset Project Data Reports;
2. The offset verification team must include a ranking of GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary by amount of contribution to total CO_2e emissions, GHG reductions, and GHG removal enhancements, and a ranking of GHG emissions sources, GHG sinks, or GHG reservoirs with the largest calculation uncertainty; and

3. The offset verification team must include a qualitative narrative of uncertainty risk assessment in the following areas as applicable to the Compliance Offset Protocol:
   a. Data acquisition equipment;
   b. Data sampling and frequency;
   c. Data processing and tracking;
   d. Project baseline and ~~annual~~project GHG emissions, GHG reductions, and GHG removal enhancement calculations;
   e. Data reporting; and
   ~~f. Chain of custody requirements; and~~
   ~~g~~f. Management policies or practices in developing Offset Project Data Reports.

(H) After completing the analysis in section 95977.1(b)(3)(G), the offset verification team must include in the sampling plan a list which includes the following:
1. GHG emissions sources, GHG sinks, and GHG reservoirs that will be targeted for document reviews to ensure conformance with the Compliance Offset Protocol and data checks as specified in section 95977.1(b)(3)(L) and an explanation of why they were chosen;
2. Methods used to conduct data checks for each GHG emissions source, GHG sink, and GHG reservoir; and
3. A summary of the information analyzed in the data checks and document reviews conducted for each GHG emissions source, GHG sink, and GHG reservoir.

(I) The sampling plan list, prepared pursuant to section 95977.1(b)(3)(H), must be updated and finalized prior to the completion of offset verification services. The final sampling plan must describe in detail how the GHG emissions sources,

GHG sinks, and GHG reservoirs with identified risk, subject to data checks, were reviewed for accuracy.

(J) The offset verification team must revise the sampling plan to describe tasks completed or needed to be completed by the offset verification team as relevant information becomes available and potential issues emerge of offset material misstatement or nonconformance with the requirements of the Compliance Offset Protocol and this article.

(K) The verification body must retain the sampling plan in paper, electronic, or other format for a period of not less than 15 years following the submission of each Offset Verification Statement. The sampling plan must be made available to ARB or the Offset Project Registry within 10 calendar days upon request. The verification body must also retain all material received, reviewed, or generated to render an Offset Verification Statement for an Offset Project Operator or Authorized Project Designee for 15 years following the submittal of each Offset Verification Statement. The documentation must allow for a transparent review of how a verification body reached its conclusion in the detailed verification report and Offset Verification Statement.

(L) Data Checks for Offset Project Data Reports. To determine the reliability of the submitted Offset Project Data Report, the offset verification team must use data checks. Such data checks must focus first on the largest and most uncertain estimates of project baseline GHG emissions, project emissions, GHG reductions, and GHG removal enhancements, and the offset verification team must:

1. Use data checks to ensure that the appropriate methodologies and GHG emission factors have been applied in calculating the project baseline and annual GHG

emissions, project emissions, GHG reductions, and GHG removal enhancements calculations in the Compliance Offset Protocol;

2. Choose GHG emissions sources, project emissions, GHG sinks, and GHG reservoirs for data checks based on their relative sizes and risks of offset material misstatement or nonconformance as indicated in the sampling plan;

3. Use professional judgment in the number of data checks required for the offset verification team to conclude with reasonable assurance whether the Offset Project Operator's or Authorized Project Designee's total reported GHG reductions and GHG removal enhancements are free of offset material misstatement and the Offset Project Data Report otherwise conforms to the requirements of the Compliance Offset Protocol and this article. At a minimum a data check must include the following:

   a. Tracing data in the Offset Project Data Report to its origin;

   b. Looking at the process for data compilation and collection;

   c. Reviewing all GHG inventory designs for GHG sources, GHG sinks, and GHG reservoirs, and sampling procedures, if applicable;

   d. Recalculating GHG emissions, project emissions, GHG reductions, and GHG removal enhancements estimates to check original calculations;

   e. Reviewing calculation methodologies used by the Offset Project Operator or Authorized Project Designee for conformance with the Compliance Offset Protocol and this article;

f. Reviewing meter and fuel analytical instrumentation calibration, if applicable; and

g. Reviewing the quantification from models approved for use in the Compliance Offset Protocol, if applicable; and

4. Compare its own calculated results for the data checks conducted with the reported offset project data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be identified. The comparison of data checks must also include a narrative to indicate which GHG emissions sources, GHG sinks, and GHG reservoirs were checked, the types and quantity of data that were evaluated for each GHG emissions source, GHG sink, and GHG reservoir, how the data checks were calculated including calculations, and any discrepancies that were identified.

(M) Offset Project Data Report Modifications. As a result of review by the offset verification team and prior to completion of an Offset Verification Statement, the Offset Project Operator or Authorized Project Designee must make any possible improvements or corrections to the submitted Offset Project Data Report, and a revised Offset Project Data Report must be submitted to ARB or the Offset Project Registry. If the Offset Project Operator or Authorized Project Designee does not make all possible improvements or corrections to the Offset Project Data Report, the verification body must issue an Adverse Offset Verification Statement. Documentation for all Offset Project Data Report submittals must be retained by the Offset Project Operator or Authorized Project Designee for the length of time specified in section 95976(e)(2).

(N) To verify that the Offset Project Data Report is free of offset material misstatement, the offset verification team must make its own determination of GHG reductions or GHG removal enhancements relative to the project baseline using the data check conducted pursuant to section 95977.1(b)(3)(L), and must determine whether there is reasonable assurance that the Offset Project Data Report does not contain an offset material misstatement for the Offset Project Operator or Authorized Project Designee, on a CO_2e basis. To assess conformance with this article and the Compliance Offset Protocol the offset verification team must review the methods and factors used to develop the Offset Project Data Report for adherence to the requirements of this article and the Compliance Offset Protocol and ensure that other requirements of this article are met.

(O) Issues Log. The offset verification team must keep a log of any issues identified in the course of offset verification services that may affect determinations of offset material misstatement and nonconformance. The issues log must identify the section of this article or Compliance Offset Protocol related to the nonconformance, if applicable, and indicate that the issues were corrected by the Offset Project Operator or Authorized Project Designee prior to completing the offset verification services. Any other concerns that the offset verification team has with the preparation of the Offset Project Data Report must be documented in the issues log. The issues log must indicate whether the issues could have any bearing on offset material misstatement or conformance.

(P) An assessment of offset material misstatement is conducted for ~~annual~~ net GHG reductions and GHG removal enhancements achieved in a given Reporting Period relative to the project baseline in that Reporting Period in metric tons of CO_2e.

(Q) The offset verification team must determine whether the GHG reductions and GHG removal enhancements quantified and reported in the Offset Project Data Report contain an offset material misstatement using the following equation:

$$Percent\ error = \frac{\sum[Discrepancies + Omissions + Misreporting]\ x\ 100\%}{Total\ Reported\ Emission\ Reductions}$$

~~$$Percent\ error = \sum \frac{[Discrepancies + Omissions + Misreporting] \times 100\%}{Total\ reported\ emissions}$$~~

Where:

"Discrepancies" means any differences between the reported GHG value for sources, sinks, and reservoirs for the project baseline ~~emissions,~~ or project and the verifier calculated GHG value ~~GHG emissions, GHG reductions, and GHG removal enhancements and GHG emissions, project emissions, GHG reductions, and GHG removal enhancements~~ for a data source subject to data checks in 95977.1(b)(3)(L) calculated by the offset verification team. Any discrepancies identified must include the positive or negative impact of the GHG source, sink, or reservoir on the total reported GHG emission reductions and removal enhancements when input into the offset material misstatement equation.

"Omissions" means any GHG emissions or removals associated with required sources, sinks, and reservoirs for the project baseline ~~emissions,~~ or project ~~GHG reductions, project emissions, and GHG removal enhancements~~ that the offset verification team concludes must be part of the Offset Project Data Report, but were not included by the Offset Project Operator or Authorized Project Designee in the Offset Project Data Report. Any omissions found by the offset verification

team must include the positive or negative impact of the omission on the total reported GHG emission reductions and removal enhancements when input into the offset material misstatement equation.

"Misreporting" means duplicative, incomplete, or other GHG emissions or removals for required sources, sinks, and reservoirs in the project baseline or project ~~emissions, project emissions, GHG reductions, and GHG removal enhancements~~ the offset verification team concludes should, or should not, be part of the Offset Project Data Report. Any misreporting found by the offset verification team must include the positive or negative impact of the misreporting on the total reported GHG emission reductions and removal enhancements when input into the offset material misstatement equation.

"Total reported emission reductions" means ~~annual reported~~ net GHG reductions and GHG removal enhancements reported by the Offset Project Operator or Authorized Project Designee for an Offset Project Data Report relative to the project baseline for that Offset Project Data Report in metric tons CO_2e.

(R) Completion of offset verification services must include:

1. Offset Verification Statement. Upon completion of the offset verification services pursuant to section 95977.1(b), the verification body must complete an Offset Verification Statement for each Offset Project Data Report for which offset verification services were conducted and provide it to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry by the verification deadline pursuant to section 95977(d). Before the Offset

Verification Statement is completed, the verification body must have the offset verification services and findings of the offset verification team independently reviewed within the verification body by an independent reviewer not involved in offset verification services for that offset project.

2. The independent reviewer shall serve as the final check of the offset verification team's work to identify any significant concerns, including:
   a. Errors in planning;
   b. Errors in data sampling; and
   c. Errors in judgment by the offset verification team that are related to the draft offset verification statement.
3. The independent reviewer must maintain independence from the offset verification services by not making specific recommendations about how the offset verification services should be conducted. The independent reviewer will review documents applicable to the offset verification services provided and identify any failure to comply with the requirements of this article or with the verification body's internal policies and procedures for providing offset verification services. The independent reviewer must concur with the offset verification findings before the Offset Verification Statement can be issued.
4. When the offset verification team completes its findings:
   a. The verification body must provide to the Offset Project Operator or Authorized Project Designee a detailed verification report <u>for each Offset Project Data Report for which offset verification services were conducted</u>. The detailed verification report must at a minimum include the Offset Verification Plan, the detailed comparison of the data checks conducted

during offset verification services pursuant to section 95977.1(b)(3)(L), including the required narrative, the issues log identified in the course of offset verification activities and the issue resolutions, and any qualifying comments on findings during offset verification services. The detailed verification report must also include the calculations performed in 95977.1(b)(3)(Q) with enough detail to understand the relationships between the data checks and the offset material misstatement evaluation, and be made available to ARB within 10 calendar days upon request. If the Offset Verification Statement is being submitted to an Offset Project Registry, then the verification body must submit the detailed verification report to the Offset Project Registry with the Offset Verification Statement. The detailed verification report must be submitted to the Offset Project Operator or Authorized Project Designee at the same time or before the Offset Verification Statement is submitted to ARB or the Offset Project Registry.

b. The verification body must provide the Offset Verification Statement to the Offset Project Operator or Authorized Project Designee and ARB or the Offset Project Registry, attesting to ARB whether the verification body has found the submitted Offset Project Data Report to be free of offset material misstatement, and whether the Offset Project Data Report is in conformance with the requirements of this article and the Compliance Offset Protocol.

c. A Compliance Offset Protocol may restrict the use of a Qualified Positive Offset Verification Statement for

certain project types, in which case the verification body must submit either a Positive Offset Verification Statement or an Adverse Offset Verification Statement. In the case of a Qualified Positive Offset Verification Statement, when not restricted by a Compliance Offset Protocol, the verification body will qualify the Offset Verification Statement to indicate any non-conformances allowed for a qualified Positive Offset Verification Statement as defined in section 95802 contained within the Offset Project Data Report and that these non-conformances do not result in an offset material misstatement.

d. The offset verification team must have a final discussion with the Offset Project Operator or Authorized Project Designee explaining their findings and notifying the Offset Project Operator or Authorized Project Designee of any unresolved issues noted in the issues log before the Offset Verification Statement is finalized and submitted to the Offset Project Registry or ARB.

e. The lead verifier in the offset verification team must attest to ARB in the Offset Verification Statement that the offset verification team has carried out all offset verification services as required by this article, and the lead verifier who has conducted the independent review of offset verification services and findings must attest to his or her independent review on behalf of the verification body and his or her concurrence with the offset verification findings.

f. The lead verifier must attest in the Offset Verification Statement, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California that the offset verification team has carried out all offset verification services as required by sections 95977.1, ~~and~~ 95977.2, and the applicable Compliance Offset Protocol and the findings are true, accurate, and complete and have been independently reviewed by an independent reviewer as required under sections 95977.1(b)(3)(R)(1.) through 95977.1(b)(3)(R)(3.)."

5. Prior to the verification body providing an Adverse Offset Verification Statement to ARB or the Offset Project Registry, the Offset Project Operator or Authorized Project Designee must be provided at least 10 working days to modify the Offset Project Data Report to correct any offset material misstatement or nonconformance found by the offset verification team. The modified Offset Project Data Report and Offset Verification Statement must be submitted to ARB or the Offset Project Registry by the applicable verification deadline, unless the Offset Project Operator or Authorized Project Designee makes a request to ARB pursuant to section 95977.1(b)(3)(R)(6.).

6. If the Offset Project Operator or Authorized Project Designee and the verification body cannot reach agreement on modifications to the Offset Project Data Report that result in a Positive Offset or Qualified Positive Offset Verification Statement due to a disagreement on the requirements of this article or Compliance Offset Protocol, the Offset Project Operator or Authorized Project Designee may petition ARB to make a decision as to the verifiability of the submitted Offset Project Data Report.

7. If ARB determines that the Offset Project Data Report does not meet the standards and requirements specified in this article, the Offset Project Operator or Authorized Project Designee must provide any additional information within 30 calendar days of the ARB determination. ARB will review the new information and notify the Offset Project Operator or Authorized Project Designee and verification body of its final decision. In re-verifying a revised Offset Project Data Report, the verification body and offset verification team shall be subject to the requirements in sections 95977.1(b)(3)(R)(1.) through 95977.1(b)(3)(R)(4.) and must submit the revised Offset Verification Statement to ARB or the Offset Project Registry within 15 calendar days.

(S) Upon submission of the Offset Verification Statement to ARB or the Offset Project Registry, the Offset Project Data Report must be considered final and no further changes may be made. All offset verification requirements of this article shall be considered complete.

(T) If the Executive Officer finds a high level of conflict of interest existed between a verification body and an Offset Project Operator or Authorized Project Designee pursuant to section 95979(b)(3) and section 95979(b)(4), or an Offset Project Data Report that received a Positive Offset or Qualified Positive Offset Verification Statement fails an ARB audit, the Executive Officer may set aside the Positive Offset or Qualified Positive Offset Verification Statement submitted by the verification body and require the Offset Project Operator or Authorized Project designee to have the Offset Project Data Report re-verified by a different verification body within 90 calendar days of this finding.

(U) Upon request by ARB or the Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide

the data used to generate an Offset Project Data Report, including all data available to the offset verification team in the conduct of offset verification services, within 10 working days of the request.

(V) Upon request by ARB or the Offset Project Registry the verification body must provide ARB or the Offset Project Registry the detailed verification report given to the Offset Project Operator or Authorized Project Designee, as well as the sampling plan, contracts for offset verification services, and any other supporting documentation. All documentation must be provided by the verification body to ARB or the Offset Project Registry within 10 working days of the request.

(W) Upon written notification by ARB the verification body and its staff must be available for an offset verification services audit when providing offset verification services for an offset project listed with ARB or an Offset Project Registry using a Compliance Offset Protocol.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95978. Offset Verifier and Verification Body Accreditation.

(a) An offset verifier or verification body must meet the accreditation requirements in section 95132 of MRR to provide offset verification services to verify GHG emission reductions and GHG removal enhancements for offset projects listed pursuant to this article. Accreditation of verification bodies and offset verifiers for verifying Offset Project Data Reports under this article must be achieved separately from accreditation for verifying reports submitted under the MRR.

(b) For purposes of this article, the subcontractor requirements in section 95132(e) of the MRR must be applied to the Offset Project Operator and/or Authorized Project Designee and not a reporting entity.

(c) An ARB accredited verification body must make itself and its personnel available for an ARB audit.

(d) An ARB accredited offset verification body may employ or contract with technical experts not accredited by ARB to assist in offset verification.

(1) All technical experts must be listed on the Notice of Offset Verification Services as required in section 959771.1(b) and must be included in the evaluation for conflict of interest as required in section 95979.

(2) Technical experts must be under the direct supervision of an ARB accredited offset verifier while performing verification activities.

(3) Technical experts may assist in underlying offset verification tasks, but may not be responsible for completing any offset verification services as defined in 95820(a)(238).

(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.

(f) "Technical expert," for purposes of this section, means a person, who is not an ARB accredited verifier, with a demonstrated expertise in a particular technical area hired by the verification body to assist with an underlying offset verification task(s) that requires that particular expertise. Technical expert may also include verification body staff working to get the required experience to become an ARB accredited verifier.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95979. Conflict of Interest Requirements for Verification Bodies and Offset Verifiers for Verification of Offset Project Data Reports.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and offset verifiers accredited by ARB to perform

offset verification services for Offset Project Operators ~~or~~, and Authorized Project Designees, if applicable, as well as any subcontractors utilized by the verification body for the offset verification services.

(b) The potential for a conflict of interest must be deemed to be high where:

(1) The verification body and Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, share any senior management staff or board of directors membership, or any of the senior management staff of the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, have been employed by the verification body, or vice versa, within the previous three years; or

(2) Within the previous five years, any staff member of the verification body or any related entity has provided to the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, any of the following non-offset verification services:

(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~~, and Authorized Project Designee, if applicable;

(G) Preparing or producing GHG-related manuals, handbooks, or procedures specifically for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable;

(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~~, and Authorized Project Designee, if applicable;

(K) Bookkeeping or other services related to the accounting records or financial statements;

(L) Any service related to information systems, including International Organization for Standardization 14001 ~~c~~Certification for Environmental Management (ISO 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~~, and Authorized Project Designee, if applicable, that relates to the Offset Project Operator's ~~or~~, and

Authorized Project Designee's, if applicable, 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~~, and Authorized Project Designee, if applicable;

(R) Any legal services; ~~and~~

(S) Expert services to the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, or a legal representative for the purpose of advocating the Offset Project Operator's ~~or~~, and Authorized Project Designee's, if applicable, interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony ~~.~~; and

(T) Third-party certification of a facility to meet the requirements set forth by the United Nations Environment Programme Ozone Secretariate's Technology and Assessment Panel (TEAP) for ozone depleting substances destruction.

"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.

(3) The potential for conflict of interest will be deemed to be high when any member of the verification body provides any type of incentive to an Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, to secure an offset verification services contract.

(4) The potential for a conflict of interest will also be deemed to be high where any member of the verification body has provided offset verification services for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, except within the time periods in which the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, is allowed to use the same verification body as specified in section 95977.1(a).

(c) The potential for a conflict of interest must be deemed to be low where no potential for a conflict of interest is found under section 95979(b) and any non-offset verification services provided by any member of the verification body to the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, within the last five years are valued at less than 20 percent of the fee for the proposed offset verification, except where medium conflict of interest related to personal or family relationships is identified pursuant to section 95979(d).

(d) The potential for a conflict of interest must be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95979(b) and 95979(c), or where there are any instances of personal or familial relationships between the verification body and management or employees of the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and when a conflict of interest self-evaluation is submitted pursuant to section 95979(g). If a verification body identifies a medium potential for conflict of interest and intends to provide offset verification services for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, for an offset project listed with ARB or an Offset Project Registry, the verification body must submit, in addition to the submittal requirements specified in section

95979(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan must include:

(1) A demonstration that any members with potential conflicts have been removed and insulated from the project;

(2) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed; and

(3) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(e) Conflict of Interest Submittal Requirements for Accredited Verification Bodies. Before providing any offset verification services, the verification body must submit to the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, ~~and~~ ARB ~~or~~and the Offset Project Registry, a self-evaluation of the potential for any conflict of interest that the verification body, its staff, its related entities, or any subcontractors performing offset verification services may have with the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, for which it will perform offset verification services. Offset verification services shall not commence prior to approval of the conflict of interest self-evaluation by ARB or the Offset Project Registry pursuant to section 95979(f). The submittal must include the following:

(1) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95979(b), (c), and (d);

(2) Identification of whether any member of the offset verification team has previously provided offset verification services for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and, if so, the years in which such offset verification services were provided; and

(3) Identification of whether any member of the offset verification team or related entity has engaged in any non-offset verification services of any nature with the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, either within or outside California during the previous ~~three~~five years. If non-offset verification services have previously been provided, the following information must also be submitted:

(A) Identification of the nature and location of the work performed for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and whether the work is similar to the type of work to be performed during offset verification;

(B) The nature of past, present, or future relationships with the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, including:

1. Instances when any member of the offset verification team has performed or intends to perform work for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable;
2. Identification of whether work is currently being performed for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and if so, the nature of the work;
3. How much work was performed for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, in the last ~~three~~five years, in dollars;
4. Whether any member of the offset verification team has any contracts or other arrangements to perform work for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, or a related entity; and
5. How much work related to GHG reductions and GHG removal enhancements the offset verification team has performed for the Offset Project Operator ~~or~~, and Authorized

Project Designee, if applicable, or related entities in the last ~~three~~five years, in dollars;

(C) Explanation of how the amount and nature of work previously performed is such that any member of the offset verification team's credibility and lack of bias should not be under question;

(D) A list of names of the staff that would perform offset verification services for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and a description of any instances of personal or family relationships with management or employees of the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, that potentially represent a conflict of interest;

(E) Identification of any other circumstances known to the verification body, or Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, that could result in a conflict of interest; and

(F) Attest, in writing, to ARB as follows:
"I certify under penalty of perjury of the laws of the State of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(f) Approval of Conflict of Interest Submittals. ARB or the Offset Project Registry must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform the offset verification services for the Offset Project Operator and Authorized Project Designee, if applicable.

(1) ARB or the Offset Project Registry has 30 calendar days to make a determination whether to accept or deny the conflict of interest submittal and notify the verification body whether it may proceed with the offset verification services for the Offset Project Operator and Authorized Project Designee, if applicable.

(A) If ARB or an Offset Project Registry requests revisions to the conflict of interest self evaluation prior to approval, the verification body must resubmit the revised conflict of interest self evaluation within ten calendar days of such request.

(B) If ARB or the Offset Project Registry determines that the verification body or any member of the offset verification team meets the criteria in section 95979(b), ARB or the Offset Project Registry shall find a high potential conflict of interest and offset verification services may not proceed.

(C) If ARB or the Offset Project Registry determines that there is a low potential conflict of interest, offset verification services may proceed.

(D) If ARB or the Offset Project Registry determines that the verification body or any member of the offset verification team have a medium potential for conflict of interest, ARB or the Offset Project Registry shall evaluate the conflict of interest mitigation plan submitted by the verification body pursuant to section 95979(d), and may request additional information from the applicant to complete the determination. In determining whether offset verification services may proceed, ARB or the Offset Project Registry may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related entities, and its subcontractors with the Offset Project Operator and Authorized Project Designee, if applicable, and related entities, and the cost of the offset verification services to be performed. If ARB or the Offset Project Registry determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, ARB or the Offset Project Registry will authorize the verification body to provide offset verification services.

(2) If the offset project was listed with an Offset Project Registry, the conflict of interest self-evaluation acceptance or denial notification will be given by the Offset Project Registry.

(gf) Monitoring Conflict of Interest Situations.

(1) After commencement of offset verification services, the verification body must monitor and immediately make full disclosure, in writing, to ARB ~~or~~and the Offset Project Registry regarding any potential for a conflict of interest situation that arises for an offset project using a Compliance Offset Protocol. This disclosure must include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body must continue to monitor arrangements or relationships that may be present for a period of one year after the completion of offset verification services for an offset project using a Compliance Offset Protocol. During that period, within 30 days of the verification body or any verification team member entering into any contract with the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, for which the verification body has provided offset verification services, the verification body must notify ARB ~~or~~and the Offset Project Registry of the contract and the nature of the work to be performed. ARB or the Offset Project Registry, within 30 working days, will determine the level ~~or~~ of conflict using the criteria in sections 95979(a) through (d), if the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, must re-verify their Offset Project Data Report, and if accreditation revocation is warranted by ARB.

(3) The verification body must notify ARB ~~or~~and the Offset Project Registry within 30 calendar days, of any emerging conflicts of interest during the time offset verification services are being provided for an offset project using a Compliance Offset Protocol.

(A) If ARB or the Offset Project Registry determines that an emerging potential conflict disclosed by the verification body is medium risk, and this risk can be mitigated, then the verification body meets the conflict of interest requirements to continue to provide offset verification services for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and will not be subject to suspension or revocation of accreditation as specified in section 95132(d) of MRR.

(B) If ARB or the Offset Project Registry determines that an emerging potential conflict disclosed by the verification body is medium or high risk, and this risk cannot be mitigated, then the verification body will not be able to continue to provide offset verification services for the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, and may be subject to the suspension or revocation of accreditation by ARB under section 95132(d) of MRR.

(4) The verification body must report to ARB and the Offset Project Registry, if applicable, any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of offset verification services.

(5) ARB may void a Positive Offset or Qualified Positive Offset Verification Statement received in section 95981 if it discovers a potential conflict of interest has arisen for any member of the offset verification team. In such a case, the Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, shall be provided 90 calendar days to complete re-verification.

(6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in section 95132(d) of MRR.

(hg) Specific Requirements for Air Quality Management Districts and Air Pollution Control Districts.

(1) If an air district has provided or is providing any services listed in section 95979(b)(2) as part of its regulatory duties, those services do not constitute non-verification services or a potential for high conflict of interest for purposes of this article;

(2) Before providing offset verification services, an air district must submit a conflict of interest self-evaluation pursuant to 95979(e) for each Offset Project Operator ~~or~~, and Authorized Project Designee, if applicable, for which it intends to provide offset verification services. As part of its conflict of interest self-evaluation submittal under section 95979(e), the air district shall certify that it will prevent conflicts of interests and resolve potential conflict of interest situations pursuant to its policies and mechanisms submitted under section 95132(b)(1)(G) of MRR;

(3) If an air district hires a subcontractor who is not an air district employee to provide offset verification services, the air district shall be subject to all of the requirements of section 95979.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95979.1 Additional Requirements for Air Quality Management Districts and Air Pollution Control Districts.

(a) The following requirements will apply to air districts that meet the requirements under section 95978 to become accredited as an offset verification body and/or the requirements under section 95986 to meet the requirements as an approved Offset Project Registry:

(1) The air district may:

(A) Register with ARB pursuant to section 95830; and

(B) Hold compliance instruments as a voluntarily associated entity pursuant to section 95814.

(2) The air district may not:

(A) Be an Offset Project Operator or Authorized Project Designee for any offset project for which it provides offset verification services pursuant to sections 95977, 95977.1, and 95977.2, and for which the air district will subsequently request the issuance of ARB offset credits pursuant to section 95981;

(B) Be an Offset Project Operator or Authorized Project Designee for any offset project for which it provides registry services pursuant to section 95987, and for which the air district will subsequently request the issuance of ARB offset credits pursuant to section 95981; and

(C) Be an offset verification body for any offset project developed using a Compliance Offset Protocol for which it would provide registry services pursuant to section 95987.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95980. Issuance of Registry Offset Credits.

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(c) Determination for Timing and Duration of Initial Crediting Periods for Offset Projects Submitted Through an Offset Project Registry. The initial crediting period will begin with the date that the first verified GHG emission reductions and GHG removal enhancements occur, according to the first Positive Offset or Qualified Positive Offset Verification Statement that is received by an Offset Project Registry, unless otherwise specified in the applicable Compliance Offset Protocol. An early action offset project that transitions pursuant to section 95990(k) will begin its initial crediting period pursuant to section 95990(k)(2).

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95980.1 Process for Issuance of Registry Offset Credits.

(a) An Offset Project Registry may issue a registry offset credit that meets the requirements of sections 95980(a) and (b) to an Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator ~~pursuant to section 95974(a)(1)~~ to receive registry offset credits, no later than 15 calendar days after an Offset Project Registry makes a determination pursuant to section 95980(b).

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(c) Notice of Determination of Issuance of Registry Offset Credits. Not later than 15 calendar days after an Offset Project Registry issues a registry offset credit, an Offset Project Registry will notify the Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator ~~pursuant to section 95974(a)(1)~~ of the issuance.

(d) Requests for Additional Information. An Offset Project Registry may request additional information for offset projects seeking issuance of registry offset credits from the Offset Project Operator, Authorized Project Designee or verification body.

(1) An Offset Project Registry may request any additional information from the Offset Project Operator, Authorized Project Designee, if applicable, or the verification body within the timeframe specified in section 95980(b) before issuing registry offset credits for an offset project that meets the requirements of sections 95980(a) and (b).

(2) If an Offset Project Registry determines the information submitted pursuant to sections 95980(a), 95980(b), and 95980.1(d)(2) does not meet the requirements for issuance of registry offset credits, then an Offset Project Registry must deny issuance of registry offset credits. The Offset Project Operator or Authorized Project Designee may petition an Offset Project Registry within 10 days of denial for a review

of the information submitted pursuant to sections 95980(a), 95980(b), and 95980.1(d)(2) and respond to any issues that prevent the issuance of registry offset credits.

(3) An Offset Project Registry must make a final determination within 30 calendar days of receiving the Offset Project Operator's or Authorized Project Designee's request in section 95980.1(d)(2) and may request additional information from the Offset Project Operator, Authorized Project Designee, if applicable, or verification body.

(4) If an Offset Project Registry determines not to issue registry offset credits, the Offset Project Registry must submit a detailed report to ARB that describes why they came to a negative determination.

(5) If an Offset Project Registry determines not to issue registry offset credits, the Offset Project Operator or Authorized Project Designee may request that ARB make a final determination on whether the GHG reductions or removal enhancements achieved by the offset project meet the requirements for registry offset credit issuance. In making this determination, ARB may consult with the Offset Project Operator, Authorized Project Designee, if applicable, verification body, and Offset Project Registry before making the final determination.

(6) If after reviewing all of the information, ARB determines that the GHG reductions or removal enhancements meet the requirements for registry offset credit issuance, the Offset Project Registry will issue registry offset credits in the amount of GHG reductions or removal enhancements verified to have been achieved by the offset project for the applicable Reporting Period(s).

(ed) At the time of issuance or after notifying the Offset Project Operator, Authorized Project Designee, or any other third party authorized by the Offset Project Operator ~~pursuant to section 95974(a)(1)~~ to receive registry offset credits, of the issuance, the Offset Project Registry will create a unique serial number for each registry offset credit.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95981. Issuance of ARB Offset Credits.

(a) One ARB offset credit, which represents one metric ton of CO_2e for a direct GHG emission reduction or direct GHG removal enhancement, will be issued only if:

(1) ARB or an Offset Project Registry has listed the offset project pursuant to section 95975;

(2) The GHG emission reductions and GHG removal enhancements were issued a Positive Offset or Qualified Positive Offset Verification Statement pursuant to sections 95977.1 and 95977.2; and

(3) ARB or an Offset Project Registry has received a Positive Offset or Qualified Positive Offset Verification Statement issued and attested to by an ARB-accredited verification body for the Offset Project Data Report for which registry offset credits were issued pursuant to section 95980.1, if the offset project was submitted for listing with an Offset Project Registry, or for which ARB offset credits would be issued pursuant to section 95981.1.

(b) Requirements for Offset Projects Submitted Through an Offset Project Registry Seeking Issuance of ARB Offset Credits. If an Offset Project Operator or Authorized Project Designee provides information for listing pursuant to section 95975, monitors and reports pursuant to section 95976, and has their offset project verified pursuant to sections 95977, 95977.1, and 95977.2 through an Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide the following information to ARB for issuance of ARB offset credits pursuant to section 95981.1:

(1) The attestations required in sections 95975(c)(1), 95975(c)(2), 95975(c)(3), 95976(d)(5), 95977.1(b)(3)(R)(4.)(b.),

95977.1(b)(3)(R)(4.)(e.), and 95977.1(b)(3)(R)(4.)(f.) and any in the applicable Compliance Offset Protocol;

(2) Offset project listing information submitted to an Offset Project Registry pursuant to sections 95975(c) and (e);

(3) The original and final Offset Project Data Reports submitted to an Offset Project Registry pursuant to sections 95976(d), 95977.1(b)(3)(M), and 95977.1(b)(3)(R)(5.); and

(4) Offset Verification Statements submitted pursuant to section 95977.1(b)(3)(R)(4.)(b.).

(5) The Offset Project Operator, or Authorized Project Designee, if applicable, must submit a request for issuance of ARB offset credits to ARB for each Offset Project Data Report for which they are seeking issuance of ARB offset credits.

(A) If the ARB offset credits are only being issued into the Holding Account that belongs to the Offset Project Operator, the Authorized Project Designee may submit the request for issuance of ARB offset credits to ARB. If the ARB offset credits will be issued into any other Holding Account(s) other than the Holding Account that belongs to the Offset Project Operator, only the Offset Project Operator may submit the request for issuance of ARB offset credits to ARB.

(B) The request for issuance of ARB offset credits must identify which Holding Accounts the ARB offset credits should be placed into and how many ARB offset credits will be placed into each Holding Account. Consistent with section 95974, the Offset Project Operator may request that ARB offset credits are placed into the Holding Account of the Authorized Project Designee, or another third party not prohibited to hold compliance instruments under this Article. Any party receiving ARB offset credits at the time of ARB offset credit issuance must have a tracking system account with ARB.

(C) The request for issuance of ARB offset credits may be provided to ARB when the Offset Project Operator or Authorized Project Designee, if applicable, submits the information in sections 95981(b)(1) through (4) but must be provided to ARB before it will issue ARB offset credits pursuant to section 95981.1. If the offset project was listed by an Offset Project Registry, the request for issuance of ARB offset credits may not be provided to ARB until the Offset Project Registry has issued registry offset credits for the applicable Offset Project Data Report(s).

(c) 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 meets the requirements of sections 95977, 95977.1, and 95977.2 within 45 calendar days of receiving ~~it~~complete and accurate information.

(d) Before ARB issues an ARB offset credit pursuant to section 95981.1 for GHG reductions and GHG removal enhancements achieved by an offset project in a Reporting Period,~~an Offset Verification Statement~~ the Offset Project Operator or Authorized Project Designee must provide the following attestations, in writing, to ARB:

(1) "I certify under penalty of perjury under the laws of the State of California the GHG reductions or GHG removal enhancements for [project] from [date] to [date] have been measured in accordance with the [appropriate ARB Compliance Offset Protocol] and all information required to be submitted to ARB is true, accurate, and complete.";

(2) "I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes arising from the enforcement of provisions in this article.";

(3) "I understand that the offset project activity and implementation of the offset project must be in accordance with all applicable local, regional, and national environmental and health and safety regulations that apply based on the offset project location. I understand that offset projects are not eligible to receive ARB or registry offset credits for GHG reductions and GHG removal enhancements that are not in compliance with the requirements of this Article.";

(4) "I certify under penalty of perjury under the laws of the State of California all information provided to ARB for issuance of ARB offset credits is true, accurate, and complete."; and

(5) "I certify under penalty of perjury under the laws of the State of California that the GHG reductions and GHG removal enhancements for which I am seeking ARB Offset Credits have not been issued any offset credits or been used for any GHG mitigation requirements in any other voluntary or mandatory program, except, if applicable, an Offset Project Registry pursuant to section 95980.1."

(e) Determination for Timing and Duration of Initial Crediting Periods for Offset Projects Submitted Through ARB. The initial crediting period will begin with the date that the first verified GHG emission reductions and GHG removal enhancements occur, according to the first Positive Offset or Qualified Positive Offset Verification Statement that is received by ARB, unless otherwise specified in a Compliance Offset Protocol. An early action offset project that transitions pursuant to section 95990(k) will begin its initial crediting period pursuant to section 95990(k)(2).

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95981.1 Process for Issuance of ARB Offset Credits.

(a) ARB will issue an ARB offset credit for an offset project that meets the requirements of sections 95981(a) and (b) to an Offset Project Operator,

Authorized Project Designee, or any other third party ~~authorized~~requested by the Offset Project Operator pursuant to section 95981(b)(5)(B) ~~95974(a)(1)~~ to receive ARB offset credits, no later than 15 calendar days after ARB makes a determination pursuant to section 95981(c), as long as all attestations required in section 95981(d) have been received by ARB prior to its determination.

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(c) Notice of Determination of Issuance of ARB Offset Credits. Not later than 15 calendar days after ARB determines to issue~~s~~ an ARB offset credit, ARB will notify the Offset Project Operator, Authorized Project Designee, or any other third party ~~authorized~~requested by the Offset Project Operator pursuant to section 95981(b)(5)(B)~~95974(a)(1)~~ to receive ARB offset credits, of ~~the issuance~~its intent to issue ARB offset credits.

(d) Requests for Additional Information. ARB may request additional information for offset projects submitted through an Offset Project Registry seeking issuance of ARB offset credits.

(1) ARB will notify the Offset Project Operator, Authorized Project Designee, or other third party identified in section 95981(b)(5)(B)~~95974(a)(1)~~ within 15 calendar days of its determination pursuant to section 95981(c) if the information submitted pursuant to~~in~~ section 95981(b), ~~and~~ (c), and (d) is incomplete and request additional specific information.

(2) ARB may request any additional information from the Offset Project Operator, Authorized Project Designee, Offset Project Registry, or verification body before issuing ARB offset credits for an offset project that meets the requirements of section 95981. The Offset Project Operator, Authorized Project Designee, Offset Project Registry, or verification body must submit the requested information to ARB within 10 calendar days of ARB's request.

(3) If ARB determines the information submitted in sections 95981(b), 95981(c), and 95981.1(d)(2) does not meet the requirements for issuance of ARB offset credits, then ARB may deny issuance of ARB offset credits. The Offset Project Operator or Authorized Project Designee may petition ARB within 10 days of denial for a review of submitted information in sections 95981(b), 95981(c), and 95981.1(d)(2) and respond to any issues that prevent the issuance of ARB offset credits.

(4) ARB must make a final determination within 30 calendar days of receiving the request in section 95981.1(d)(3) and may request additional information from the Offset Project Operator or Authorized Project Designee, verification body, or Offset Project Registry. This determination made by the Executive Officer is final.

(e) A registry offset credit issued pursuant to section 95980.1(a) must be removed or cancelled by the Offset Project Registry within 10 calendar days of ARB notification, such that the registry offset credit is no longer available for transaction on the Offset Project Registry system. Registry offset credits must be removed or cancelled by the Offset Project Registry before ARB issues an ARB offset credit pursuant to this section. The Offset Project Registry must provide proof to ARB that the registry offset credits have been permanently removed or cancelled from the registry system.

(f) Receipt of ARB Offset Credits. ARB will transfer ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or any other third party ~~authorized~~requested by the Offset Project Operator pursuant to section 95981(b)(5)(B)~~95974(a)(1)~~ to receive ARB offset credits, within 15 working days of the notice of determination pursuant to sections 95981.1(c) and (d)(4).

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95982. Registration of ARB Offset Credits.

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(b) Transferring ~~this serial number~~the ARB offset credits to the Holding Account of the listed Offset Project Operator, Authorized Project Designee, or another third party as ~~provided in~~requested by the Offset Project Operator pursuant to section 95981(b)(5)(B)~~95974(a)(1)~~ to receive ARB offset credits, unless otherwise required by section 95983.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95983. Forestry Offset Reversals.

(a) For forest sequestration projects, a portion of ARB offset credits issued to the forest offset project will be placed by ARB into the Forest Buffer Account.

(1) The amount of ARB offset credits that must be placed in the Forest Buffer Account shall be determined as set forth in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011.

(2) ARB offset credits will be transferred to the Forest Buffer Account by ARB at the time of ARB offset credit registration pursuant to section 95982.

(3) If a forest offset project is originally submitted through an Offset Project Registry an equal number of registry offset credits must be removed or cancelled by the Offset Project Registry, such that the registry offset credit is no longer available for transaction on the Offset Project Registry system, and issued by ARB for placement in the Forest Buffer Account.

(4) The ARB offset credits placed into the Forest Buffer Account must correspond to the Reporting Period for which the ARB offset credits are issued.

(b) Unintentional Reversals. If there has been an unintentional reversal, the Offset Project Operator or Authorized Project Designee must notify ARB and the Offset Project Registry, in writing, of the reversal and provide an explanation for the nature of the unintentional reversal within 30 calendar days of its discovery.

(1) In the case of an unintentional reversal the Offset Project Operator or Authorized Project Designee shall provide in writing to ARB and an Offset Project Registry, if applicable, a verified estimate of current carbon stocks within the offset project boundary within one year of the discovery of the unintentional reversal.

(2) If ARB determines that there has been an unintentional reversal, and ARB offset credits have been issued to the offset project, ARB will retire a quantity of ARB offset credits ~~in the amount of metric tons of CO_2e reversed~~ from the Forest Buffer Account according to section 95983(b)(2)(A) or (B), as applicable.

(A) If the forest project came into the program directly under a Compliance Offset Protocol and did not transition from an Early Action Offset Program, ARB will retire ARB offset credits in the amount of metric tons CO_2e reversed for each Reporting Period.

(B) If the forest project transitioned into the program originally from an Early Action Offset Program, ARB will retire ARB offset credits from the Forest Buffer Account according to the following equation, calculated for each Reporting Period, rounded up to the nearest whole metric ton CO_2e:

$$ARB_{Retire} = \frac{ARB_{Credits}}{ARB_{Credits} + EAOP_{Credits}} \times Reversal$$

Where:

"ARB_{Retire}" is the number of ARB offset credits that must be retired from the ARB Forest Buffer Account to compensate for the unintentional reversal for the Reporting Period;

"$ARB_{Credits}$" is the total number of ARB offset credits issued to the forest project for the Reporting Period, including any ARB offset credits that were issued for early action and any that were placed into the Forest Buffer Account for the Reporting Period;

"$EAOP_{Credits}$" is the total number of early action offset credits issued to the forest project by the Early Action Offset Program for the Reporting Period, including any voluntary offset credits placed into the Early Action Offset Program's buffer account for forest projects that were not transferred to ARB's Forest Buffer Account, but excluding any early action offset credits that were issued ARB offset credits; and

"Reversal" is the total metric tons of CO_2e reversed for the Reporting Period.

(c) Intentional Reversals. Requirements for intentional reversals are as follows:

(1) If an intentional reversal occurs, the Offset Project Operator or Authorized Project Designee shall, within 30 calendar days of the intentional reversal:

(A) Give notice, in writing, to ARB and the Offset Project Registry, if applicable, of the intentional reversal; and

(B) Provide a written description and explanation of the intentional reversal to ARB and the Offset Project Registry, if applicable.

(2) Within one year of the occurrence of an intentional reversal, the Offset Project Operator or Authorized Project Designee shall submit to ARB and the Offset Project Registry, if applicable, a verified estimate of

current carbon stocks within the offset project boundary. This verified estimate may be submitted as a separate offset verification services, or incorporated into a chapter of the detailed verification report submitted pursuant to section 95977.1 when offset verification services are conducted.

(3) If an intentional reversal occurs from a forest offset project, and ARB offset credits have been issued to the offset project, the forest owner must submit to ARB for placement in the Retirement Account a quantity of valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4, ~~in the amount of metric tons of CO_2e reversed~~ within six months of notification by ARB in the amount determined pursuant to sections 95983(c)(3)(A) or (B), as applicable:~~.~~

(A) If the forest project came into the program directly under a Compliance Offset Protocol and did not transition from an Early Action Offset Program, the forest owner must turn in valid compliance instruments in the amount of metric tons CO_2e reversed for each Reporting Period.

(B) If the forest project transitioned into the program originally from an Early Action Offset Program, the forest owner must turn in valid compliance instruments according to the following equation, calculated for each Reporting Period, rounded up to the nearest metric ton CO_2e:

$$FO_{Replace} = \frac{ARB_{Credits}}{ARB_{Credits} + EAOP_{Credits}} \times Reversal$$

Where:

"$FO_{Replace}$" is the number of valid compliance instruments that the forest owner must turn in to compensate for the intentional reversal for the Reporting Period;

"$ARB_{Credits}$" is the total number of ARB offset credits issued to the forest project for the Reporting Period, including any ARB offset credits that were issued for early action and any that were placed into the Forest Buffer Account for the Reporting Period;

"$EAOP_{Credits}$" is the total number of early action offset credits issued to the forest project by the Early Action Offset Program for the Reporting Period, including any voluntary offset credits placed into the Early Action Offset Program's buffer account for forest projects that were not transferred to ARB's Forest Buffer Account, but excluding any early action offset credits that were issued ARB offset credits; and

"Reversal" is the total metric tons of CO_2e reversed for the Offset Project Data Report year.

(AC) Notification by ARB will occur after the verified estimate of carbon stocks referred to in section 95983(c)(2) has been submitted to ARB, or after one year has elapsed since the occurrence of the reversal if the Offset Project Operator or Authorized Project Designee fails to submit the verified estimate of carbon stocks.

(BD) If the forest owner does not submit valid ARB offset credits or other approved compliance instruments in the amount required pursuant to sections 95983(c)(3)(A) or (B) to ARB within six months of notification by ARB, ARB will retire a quantity of ARB offset credits equal to the difference between the number of metric tons of CO_2e determined pursuant to sections 95983(c)(3)(A) or (B) and the number of retired approved compliance instruments ~~in the amount of metric tons of CO_2e reversed~~ from the Forest Buffer Account and the forest owner

will be subject to enforcement action and each ARB offset credit retired from the Forest Buffer Account will constitute a separate violation pursuant to section 96014.

(4) Early Project Terminations. ~~In the event of an early forest offset project termination ARB will retire from the Forest Buffer Account a quantity of ARB offset credits in the amount calculated pursuant to project termination provisions in Compliance Offset Protocol, U.S. Forest Projects, October 20, 2011. This provision only applies to ARB offset credits that have been issued to the offset project.~~If an early project termination occurs from a forest offset project, and ARB offset credits have been issued to the offset project, the forest owner must submit to ARB for placement in the Retirement Account a quantity of valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4 in the amount determined pursuant to sections 95983(c)(4)(A), (B), or (C), whichever applies, for each Offset Project Data Report year:

(A) If the forest project came into the program directly under a Compliance Offset Protocol and did not transition from an Early Action Offset Program, the forest owner must turn in valid compliance instruments to cover the number of ARB offset credits issued to the offset project for each Reporting Period, except for improved forest management projects. If the project is an improved forest management project, the amount of metric tons CO_2e reversed must be multiplied by the compensation rate in the Compliance Offset Protocol, U.S. Forest Projects, October 20, 2011.

(B) If the forest project transitioned into the program originally from an Early Action Offset Program, the forest owner must turn in valid compliance instruments according to the following equation, calculated for each Reporting Period, except for improved forest management projects:

$$FO_{Replace} = \frac{ARB_{Credits}}{ARB_{Credits} + EAOP_{Credits}} \times Reversal$$

Where:

"$FO_{Replace}$" is the number of valid compliance instruments that the forest owner must turn in to compensate for the early project termination for each Reporting Period;

"$ARB_{Credits}$" is the total number of ARB offset credits issued to the forest project for the Reporting Period, including any ARB offset credits that were issued for early action and any that were placed into the Forest Buffer Account for the Reporting Period;

"$EAOP_{Credits}$" is the total number of early action offset credits issued to the forest project by the Early Action Offset Program for the Reporting Period, including any voluntary offset credits placed into the Early Action Offset Program's buffer account for forest projects that were not transferred to ARB's Forest Buffer Account, but excluding any early action offset credits that were issued ARB offset credits; and

"Reversal" is the total metric tons of CO_2e reversed for the Offset Project Data Report year.

(C) For an improved forest management project that transitioned into the program originally from an Early Action Offset Program, the forest owner must replace ARB offset credits in the amount calculated pursuant to section 95983(c)(4)(B) multiplied by the compensation rate in the Compliance Offset Protocol, U.S. Forest Projects, October 20, 2011.

(AD) ARB will notify the forest owner of how many ARB offset credits must be replaced with valid compliance instruments.~~ARB will notify the forest owner of retirement within 10 calendar days.~~

(~~B~~E) The forest owner must submit to ARB for placement in the Retirement Account a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4 for each ARB offset credit required to be replaced ~~retired by ARB from the Forest Buffer Account~~ within six months of ARB's retirement.

(~~C~~F) If the forest owner does not submit valid ARB offset credits or other approved compliance instruments to ARB in the amount required pursuant to sections 95983(c)(4)(A) or (B) within six months of ARB's retirement, ARB will retire a quantity of ARB offset credits equal to the difference between the number of metric tons of CO_2e determined pursuant to sections 95983(c)(4)(A) or (B) and the number of retired approved compliance instruments from the Forest Buffer Account and they will be subject to enforcement action and each ARB offset credit retired from the Forest Buffer Account will constitute a separate violation pursuant to section 96014.

(d) Disposition of Forest Sequestration Projects After a Reversal. If a reversal lowers the forest offset project's actual standing live carbon stocks below its project baseline standing live carbon stocks, the forest offset project will be terminated by ARB or an Offset Project Registry.

(1) If the forest offset project is terminated due to an unintentional reversal, ARB will retire from the Forest Buffer Account a quantity of ARB offset credits equal to the total number of ARB offset credits issued pursuant to section 95981, and where applicable, all ~~early action~~ARB offset credits issued to the offset project pursuant to section 95990(i) for early action, over the preceding 100 years.

(2) If the forest offset project is terminated due to an unintentional reversal, another offset project may be initiated and submitted to ARB or an Offset Project Registry for listing within the same offset project boundary.

(3) If the forest offset project has experienced an unintentional reversal and its actual standing live carbon stocks are still above the approved baseline levels, it may continue without termination as long as the unintentional reversal has been compensated by the Forest Buffer Account. The Offset Project Operator or Authorized Project Designee must continue contributing to the Forest Buffer Account in future years as quantified in section 95983(a)(1).

(4) If the forest offset project is terminated due to any reason except an unintentional reversal, new offset projects may not be initiated within the same offset project boundary, unless otherwise specified in a Compliance Offset Protocol.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95984. Ownership and Transferability of ARB Offset Credits.

(a) Initial ownership of an ARB offset credit will be with the registered Offset Project Operator, Authorized Project Designee, or another third party as ~~provided in~~requested by the Offset Project Operator pursuant to section 95981(b)(5)(B)~~95974(a)(1)~~ to receive ARB offset credits, unless otherwise required by section 95983. An ARB offset credit may be sold, traded, or transferred, unless:

(1) It has been retired, surrendered for compliance, or used to meet any GHG mitigation requirements in any voluntary or regulatory program;

(2) It resides in the Forest Buffer Account pursuant to section 95983; or

(3) It has been invalidated pursuant to section 95985.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95985. Invalidation of ARB Offset Credits.

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(b) Timeframe for Invalidation. ARB may invalidate an ARB offset credit pursuant to this section within the following timeframe if a determination is made pursuant to section 95985(f):

(1) Within eight years of issuance of an ARB offset credit, if the ARB offset credit is issued for early action pursuant to section 95990(h), or within eight years of the date that corresponds to the end of the Reporting Period for which the ARB offset credit is issued, if the ARB offset credit is issued pursuant to section 95981.1, unless one of the following requirements is met;

(A) The Offset Project Operator or Authorized Project Designee for aAn offset project developed under Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011, ~~may only be subject to invalidation within three years of issuance of an ARB offset credit if the Offset Project Data Report is re-verified pursuant to sections 95977 through 95978 by a different offset verification body within those three years~~or an early action quantification methodology approved pursuant to section 95990(c)(5) for the same project type, does the following:

1. Has a different verification body that meets the requirements for conflict of interest conduct a second regulatory verification pursuant to sections 95977 through 95978 for the same Offset Project Data Report; and

2. The second regulatory verification must occur within three years of the issuance of the ARB offset credits, and the Offset Project Operator or Authorized Project Designee must

receive a Positive or Qualified Positive Offset Verification Statement from the new verification body for the same Offset Project Data Report.

a. If the offset project is listed with an Offset Project Registry, the detailed verification report and Offset Verification Statement for the second regulatory verification must be submitted to the Offset Project Registry.

b. The Offset Project Registry must review the offset verification documents pursuant to section 95987(e)(1)(E) and submit a report to ARB that includes the details and findings of the Offset Project Registry's review.

c. The Offset Project Registry has 45 calendar days to review the offset verification information once it is received from the verification body.

d. The Offset Project Registry has an additional 15 working days to submit its report to ARB.

3. If the requirements in sections 95985(b)(1)(A)(1.) and (2.) are met, the ARB offset credits issued under the Offset Project Data Report may only be subject to invalidation according to the following timeframes:

a. Within three years of the date that corresponds to the end of the Reporting Period for which the ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95981; and

b. Within three years of the date for which ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95990(h); or

(B) The Offset Project Operator or Authorized Project Designee for aAn offset project developed under one of the protocols listed

~~below~~in section 95985(b)(1)(B)(5.) does the following:~~, may only be subject to invalidation within three Reporting Periods if a subsequent Offset Project Data Report for that offset project is verified pursuant to sections 95977 through 95978 by a different offset verification body and issued a Positive Offset or Qualified Positive Offset Verification Statement within three years of issuance of the ARB Offset Credit.~~

1. Has a subsequent Offset Project Data Report verified pursuant to sections 95977 through 95978 by a different verification body than the one which conducted the most recent verification, and that meets the requirements for conflict of interest pursuant to section 95979 and rotation of verification bodies pursuant to section 95977.1(a); and
2. The verification conducted by a different verification body for the subsequent Offset Project Data Report must be completed within, at a maximum, three years from the date that corresponds to the last time ARB offset credits were issued to the offset project. The verification of the subsequent Offset Project Data Report must result in a Positive or Qualified Positive Offset Verification Statement from the new verification body.
3. If the requirements in sections 95985(b)(1)(B)(1.) and (2.) are met, 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 according to the following timeframes:
    a. Within three years of the date that corresponds to the end of the Reporting Period for which the ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95981; and

b. Within three years of the date for which ARB offset credits are issued, if the ARB offset credits are issued pursuant to section 95990(h).

4. If an offset project developed under one of the Compliance Offset Protocols listed in section 95985(b)(1)(B)(5.) is in the last year of a crediting period, and will not have a renewed crediting period, the statute of limitations may be reduced from eight years to three years if the following requirements are met for the last Offset Project Data Report of the crediting period:

a. The Offset Project Operator or Authorized Project Designee has a different verification body that meets the requirements for conflict of interest conduct a second regulatory verification pursuant to sections 95977 through 95978 for the last Offset Project Data Report;

b. The second regulatory verification must occur within three years of the issuance of the ARB offset credits and the last Offset Project Operator or Authorized Project Designee must receive a Positive or Qualified Positive Offset Verification Statement from the new verification body for the same last Offset Project Data Report.

i. If the offset project is listed with an Offset Project Registry, the detailed verification report and Offset Verification Statement for the second regulatory verification must be submitted to the Offset Project Registry.

ii. The Offset Project Registry must review the offset verification documents pursuant to section 95987(e)(1)(E) and submit a report to

ARB that includes the details and findings of the Offset Project Registry's review.

iii. The Offset Project Registry has 45 calendar days to review the offset verification information once it is received from the verification body.

iv. The Offset Project Registry has an additional 15 working days to submit its report to ARB.

5. ~~This provision applies~~The provisions in section 95985(b)(1)(B)(1.) through (4.) apply if an offset project is developed under one of the following Compliance Offset Protocols, or any early action quantification methodologies approved pursuant to section 95990(c)(5) for the same project types;

a~~1~~. Compliance Offset Protocol Livestock Projects, October 20, 2011;

b~~2~~. Compliance Offset Protocol Urban Forest Projects, October 20, 2011; ~~and~~

c~~3~~. Compliance Offset Protocol U.S. Forest Projects, October 20, 2011~~.~~; and

d. Compliance Offset Protocol Mine Methane Capture Projects, [DATE].

(c) Grounds for Initial Determination of Invalidation. ARB may determine that an ARB offset credit is invalid for the following reasons:

(1) The Offset Project Data Report contains errors that overstate the amount of GHG reductions or GHG removal enhancements by more than ~~five~~5.00 percent;

(A) If ARB finds that there has been an overstatement by more than ~~five~~5.00 percent, ARB shall determine how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period. Within 10

calendar days of this determination, ARB will notify the verification body that performed the offset verification and the Offset Project Operator or Authorized Project Designee. Within 25 calendar days of receiving the written notification by ARB, the verification body shall provide any available offset verification services information or correspondence related to the Offset Project Data Report. Within 25 calendar days of receiving the written notification by ARB, the Offset Project Operator or Authorized Project Designee shall provide data that is required to calculate GHG reductions and GHG removal enhancements for the offset project according to the requirements of this article, the detailed offset verification report prepared by the verification body, and other information requested by ARB. The Offset Project Operator or Authorized Project Designee shall also make available personnel who can assist ARB's determination of how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period.

1. ARB will determine the actual GHG reductions and GHG removal enhancements achieved by the offset project for the applicable Reporting Period based on, at a minimum, the following information:
    a. The GHG sources, GHG sinks, and GHG reservoirs within the offset project boundary for that Reporting Period; and
    b. Any previous Offset Project Data Reports submitted by the Offset Project Operator or Authorized Project Designee, and the Offset Verification Statements rendered for those reports.
2. In determining how many GHG reductions and GHG removal enhancements were achieved by the offset project for the

applicable Reporting Period, ARB may use the following methods, as applicable:

a. The applicable Compliance Offset Protocol;

b. In the event of missing data, ARB will rely on the missing data provisions pursuant to section 95976, and, if applicable, the Compliance Offset Protocol; and

c. Any information reported under this article for this Reporting Period and past Reporting Periods.

3. ARB shall determine how many GHG reductions and GHG removal enhancements were achieved by the offset project for the applicable Reporting Period using the best information available, including the information in section 95985(c)(1)(A)(1.) and methods in section 95985(c)(1)(A)(2.), as applicable.

(B) If ARB determines that an overstatement has occurred pursuant to section 95985(c)(1), ARB shall determine the amount of ARB offset credits that correspond to the overstatement using the following equation, rounded to the nearest whole ton:

$$If: I_{ARBOC} > R_{OPDR} \times 1.05$$

$$Then: O_R = I_{ARBOC} - R_{OPDR}$$

Where:

"O_R" is the amount of overstated GHG reductions and GHG removal enhancements for the applicable Offset Project Data Report, rounded to the nearest whole ton;

"I_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report pursuant to section 95981.1 or 95990(i);

"R_{OPDR}" is the number of GHG reductions and GHG removal enhancements determined by ARB pursuant to section 95985(c)(1) for the applicable Offset Project Data Report;

(2) 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; or

(3) ARB determines that offset credits have been issued in any other voluntary or mandatory program within the same offset project boundary and for the same Reporting Period in which ARB offset credits were issued for GHG reductions and GHG removal enhancements.

(4) The following shall not be grounds for invalidation:

(A) An update to a Compliance Offset Protocol will not result in an invalidation of ARB offset credits issued under a previous version of the Compliance Offset Protocol; or

(B) A reversal that occurs under a forest offset project. If such a reversal occurs the provisions in section 95983 apply.

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(e) Identification of Affected Parties. If ARB makes an initial determination that one of the circumstances listed in section 95985(c) has occurred, ARB will identify the following parties:

(1) The current holders that hold any ARB offset credits in their Holding and/or Compliance Accounts from the applicable Offset Project Data Report;

(2) The ~~entiies~~entities for which ARB transferred any ARB offset credits from the applicable Offset Project Data Report into the Retirement Account; and

(3) The Offset Project Operator and Authorized Project Designee, and, for forest offset projects the Forest Owner(s).

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(g) Removal of Invalidated ARB Offset Credits from Holding and/or Compliance Accounts. If the Executive Officer makes a final determination pursuant to section 95985(f) that an ARB offset credit is invalid, then:

(1) ARB offset credits will be removed from any Holding or Compliance Account, as follows;

(A) If an ARB offset credit is determined to be invalid due to the circumstance listed in section 95985(c)(1), then:

1. ARB will determine which ARB offset credits will be removed from the Compliance and/or Holding Accounts of each party identified in section 95985(e)(1) according to the following equation, rounded to the nearest whole ton:

$$H_{ARBOC} = \left| \frac{TOT_{Holding}}{I_{ARBOC}} \right| O_R$$

Where:

"O_R" is the amount of overstated GHG reductions and GHG removal enhancements for the applicable Offset Project Data Report calculated pursuant to section 95985(c)(1);

"I_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report pursuant to section 95981.1 or 95990(i);

"$TOT_{Holding}$" is the total number of ARB offset credits currently being held in a Compliance and/or Holding Account by each party

identified in section 95985(e)(1) for the applicable Offset Project Data Report;

"H_{ARBOC}" is the total number of ARB offset credits, rounded to the nearest whole ton, that will be removed from the Holding and/or Compliance Account of each party identified in section 95985(e)(1).

2. ARB will determine the ~~lowest serial numbers assigned to~~ quantity of ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to section 95985(g)(1)(A) and remove a quantity of ARB offset credits~~them~~ from any Holding and/or Compliance Account of the parties identified in section 95985(e)(1).

(B) If an ARB offset credit is determined to be invalid due to the circumstances listed in sections 95985(c)(2) or (c)(3), ARB will remove all ARB offset credits issued under the applicable Offset Project Data Report from any Holding and/or Compliance Account of the parties identified in section 95985(e)(1).

(2) The parties identified pursuant to section 95985(e) will be notified of which serial numbers were removed from any Compliance and/or Holding Accounts.

(3) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were removed from any Compliance and/or Holding Accounts.

(h) Requirements for Replacement of ARB Offset Credits ~~for Non-Sequestration Offset Projects~~.

(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 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:

(A) Each party identified in section 95985(e)(2) must replace ARB offset credits in the amount calculated for the individual party according to the following equation, rounded to the nearest whole ton:

$$R_{ARBOC} = \left|\frac{TOT_{Retired}}{I_{ARBOC}}\right| O_R$$

Where:

"R_{ARBOC}" is the calculated total number of retired ARB offset credits for the applicable Offset Project Data Report, rounded to the nearest whole ton, that must be replaced by each individual party identified in section 95985(e)(2);

"$TOT_{Retired}$" is the total number of ARB offset credits for which ARB transferred the ARB offset credits from the applicable Offset Project Data Report into the Retirement Account for the individual party specified in section 95985(e)(2);

"I_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report pursuant to section 95981.1 or 95990(i);

"O_R" is the amount of overstated GHG reductions and GHG removal enhancements calculated pursuant to section 95985(c)(1) for the applicable Offset Project Data Report.

(B) Each party identified in section 95985(e)(2) must replace ARB offset credits in the amount calculated pursuant to section 95985(h)(1)(A) with valid ARB offset credits or other approved

compliance instruments pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(C) If each party identified in section 95985(e)(2) does not replace each invalid ARB offset credit in the amount calculated pursuant to section 95985(h)(1)(A) within six months of notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that party pursuant to section 96014.

1. If the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2) of MRR, ARB will require the Offset Project Operator to replace each invalidated ARB offset credit and will notify the Offset Project Operator that they must replace them.
2. If t~~T~~he Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(1)(C)(1.), the Offset Project Operator must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(h)(1)(C)(1.).
3. If the Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(1)(C)(1.), and the Offset Project Operator does not replace each invalid ARB offset credit within six months of notification by ARB pursuant to section 95985(h)(1)(C)(1.), each unreplaced invalidated ARB offset credit will constitute a violation for that Offset Project Operator pursuant to section 96014.

(D) ARB will determine the ~~lowest serial numbers assigned to~~ quantity of ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to

section 95985(h)(1)(A) and invalidate that quantity of ARB offset creditsthose serial numbers.

(E) The parties identified pursuant to section 95985(e) will be notified of the quantity of ARB offset credits thatwhich serial numbers were invalidated.

(F) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(2) If an ARB offset credit that is issued to in the Retirement Account from a non-sequestration offset project or an urban forest project, or a U.S. forest offset project on or after January 1, 2014, and is in the Retirement Account, and it is determined to be invalid pursuant to section 95985(f) for any circumstance listed in sections 95985(c)(2) and (c)(3),; then:

(A) The party identified in section 95985(e)(2) must replace each ARB offset credit it requested ARB to transfer into the Retirement Account for the applicable Offset Project Data Report with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(B) If the party identified in section 95985(e)(2) does not replace each invalid ARB offset credit within six months of the notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that party pursuant to section 96014.

1. If the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2) of MRR ARB will require the Offset Project Operator to replace each invalidated ARB offset credit and will notify the Offset Project Operator that they must replace them.

2. If tThe Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(2)(B)(1.),

the Offset Project Operator must replace each ARB offset credit with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(h)(2)(B)1.

3. If the Offset Project Operator is required to replace the ARB offset credits pursuant to section 95985(h)(2)(B)(1.), and the Offset Project Operator does not replace each invalid ARB offset credit within six months of notification by ARB pursuant to section 95985(h)(2)(B)(1.), each unreplaced invalidated ARB offset credit will constitute a violation for that Offset Project Operator pursuant to section 96014.

(C) The parties identified pursuant to section 95985(e) will be notified of which serial numbers were invalidated.

(D) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(i) Requirements for Replacement of ARB Offset Credits for U.S. Forest Offset Projects Issued ARB Offset Credits Prior to January 1, 2014.

(1) If an ARB offset credit that is issued prior to January 1, 2014 is in the Retirement Account from a U.S. forest offset project ~~is~~and it is determined to be invalid pursuant to section 95985(f) for only the circumstance listed in section 95985(c)(1), then:

(A) The Forest Owner identified in section 95985(e)(3) must replace ARB offset credits in the amount calculated according to the following equation, rounded to the nearest whole ton:

$$RF_{ARBOC} = \left|\frac{TF_{Retired}}{IF_{ARBOC}}\right| OF_R$$

Where:

"RF_{ARBOC}" is the total number of retired ARB offset credits for the applicable U.S. forest offset project's Offset Project Data Report,

rounded to the nearest whole ton, that must be replaced by the Forest Owner;

"$TF_{Retired}$" is the total number of ARB offset credits issued for the applicable U.S. forest offset project's Offset Project Data Report for which ARB transferred any ARB offset credits from into the Retirement Account;

"IF_{ARBOC}" is the number of ARB offset credits issued under the applicable Offset Project Data Report for the U.S. forest offset project pursuant to section 95981.1 or 95990(i);

"OF_R" is the amount of overstated GHG reductions and GHG removal enhancements calculated pursuant to section 95985(c)(1) for the U.S. forest offset project for the applicable Offset Project Data Report.

(B) The Forest Owner identified in section 95985(e)(3) must replace ARB offset credits in the amount calculated pursuant to section 95985(i)(1)(A) with valid ARB offset credits or other approved compliance instruments pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(C) If the Forest Owner identified in section 95985(e)(3) does not replace each invalid ARB offset credit in the amount calculated pursuant to section 95985(i)(1)(A) within six months of notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that Forest Owner pursuant to section 96014.

(D) ARB will determine the lowest serial numbers assigned to ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to section 95985(i)(1)(A) and invalidate those serial numbers.

(E) The Forest Owner identified pursuant to section 95985(e)(3) will be notified of which serial numbers were invalidated.

(F) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

(2) If an ARB offset credit in the Retirement Account from a U.S. forest offset project is determined to be invalid pursuant to section 95985(f) for any circumstance listed in sections 95985(c)(2) and (c)(3):

(A) The Forest Owner must replace each ARB offset credit transferred by ARB into the Retirement Account for the applicable Offset Project Data Report with a valid ARB offset credit or another approved compliance instrument pursuant to subarticle 4, within six months of notification by ARB pursuant to section 95985(g)(2).

(B) If the Forest Owner does not replace each invalid ARB offset credit within six months of the notice of invalidation pursuant to section 95985(g)(2), each unreplaced invalidated ARB offset credit will constitute a violation for that Forest Owner pursuant to section 96014.

(C) The parties identified pursuant to section 95985(e) will be notified of which serial numbers were invalidated.

(D) Any approved program for linkage pursuant to subarticle 12 will be notified of which serial numbers were invalidated.

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95986. Executive Officer Approval Requirements for Offset Project Registries.

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(b) The Executive Officer may approve Offset Project Registries that meet and maintain the requirements specified in this section.

(c) The Offset Project Registry must not be registered with ARB pursuant to section 95830.

(1) Offset Project Registry Approval Application. To apply for approval as an Offset Project Registry, the applicant shall submit the following information to the Executive Officer:

(A) Name of applicant;

(B) Name of president or chief executive officer;

(C) List of all board members, if applicable;

(D) Addresses of offices located in the United States;

(E) Documentation that the applicant carries at least five million U.S. dollars of professional liability insurance; and

(F) List of any judicial proceedings and administrative actions filed against the applicant within the previous five years, with a detailed explanation as to the nature of the proceedings.

(2) The applicant must submit, in writing, the procedures to screen and address internal conflicts of interest. The applicant must provide the following information to the Executive Officer:

(A) A staff, management, and board member conflict of interest policy where there are clear criteria for what constitutes a conflict of interest. The policy must:

1. Identify specific activities and limits on monetary and non-monetary gifts staff, management, or board members must not conduct or accept to meet the Offset Project Registry's internal policies of conflict of interest policy, or alternatively provide a comprehensive policy on the applicant's requirements for the reporting of any and all conflicts based on internal policies that guard against conflict of interest; and

2. Include a requirement for annual disclosure by each staff, management, or board member of any items or instances that are covered by the applicant's conflict of interest policy on an ongoing basis or for the previous calendar year.

3. The applicant must have appropriate conflict of interest and confidentiality requirements in place for any of its contractors;

(B) List of all service types provided by the applicant;

(C) The industrial sectors the applicant serves;

(D) Locations where services are provided; and

(E) A detailed organizational chart that includes the applicant and any parent, subsidiary, and affiliate companies.

(F) If the applicant under section 95986 is going to designate a subdivision of its organization to provide registry services, then the prohibition in section 95986(d)(1) on serving as an offset project consultant shall apply at the subdivision level and the applicant must provide the following general information for its self:

1. General types of services; and

2. General locations where services are provided.

(3) The applicant has the following capabilities for registration and tracking of registry offset credits issued under this article:

(A) A comprehensive registration requirement for all registry participants;

(B) Tracking ownership and transactions of all registry offset credits it issues at all times; and

(C) Possesses a permanent repository of ownership information on all transactions involving all registry offset credits it issues under this article from the time they are issued to the time they are retired or cancelled.

(d) The applicant's primary business must be operating an Offset Project Registry for voluntary or regulatory purposes and meet the following business requirements:

(1) The applicant may not act as an Offset Project Operator, Authorized Project Designee, or offset project consultant for offset projects

registered or listed on its own Offset Project Registry and developed using a Compliance Offset Protocol once approved as an Offset Project Registry. The applicant must annually disclose to ARB any non-offset project related consulting services it provides to an Offset Project Operator or Authorized Project Designee who lists a project using a Compliance Offset Project with the applicant as part of the information included in the annual report required in section 95987(j);

(2) The applicant may not act as a verification body or provide offset verification services pursuant to sections 95977.1 and 95977.2 once approved as an Offset Project Registry;

(3) If the applicant designates a subdivision of its organization to provide registry services, the applicant may not be an Offset Project Operator or Authorized Project Designee for offset projects listed at the subdivision's registry, act as a verification body, or be a covered entity or opt-in covered entity;

(4) The applicant must demonstrate experience in the continuous operation of a registry serving an environmentally-focused market for a minimum of two years in a regulatory and/or voluntary market. For the purposes of this section, an "environmentally-focused market" means a market that includes the trading of carbon-emissions based commodities. In the context of Air Quality Management Districts or Air Pollution Control Districts, "Environmentally-focused Market" includes a market for air emission reduction credits; and

(5) The applicant's primary incorporation or other business formation and primary place of business, or the primary place of business of the designated subdivision, if the applicant designates a subdivision to provide registry services pursuant to this section, must be in the United States of America.

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(j) The Offset Project Registry must have at least two years of demonstrated experience in, and requirements for, direct staff oversight ~~of the~~and review of offset projects ~~review~~, project listing, offset verification, and registry offset credit issuance ~~process~~.

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(l) Modification, Suspension, and Revocation of an Executive Order Approving an Offset Project Registry. The Executive Officer may review, and, for good cause, modify, suspend, or revoke an Executive Order providing approval to an Offset Project Registry.

(1) During revocation proceedings, the Offset Project Registry may not continue to provide registry services for ARB.

(2) Within five working days of suspension or revocation of approval, an Offset Project Registry must notify all Offset Project Operators or Authorized Project Designees for whom it is providing registry services, or has provided registry services within the past 12 months, of its suspension or revocation of approval.

(3) An Offset Project Operator or Authorized Project Designee who has been notified by an Offset Project Registry of a suspended or revoked approval must re-submit its offset project information with a new Offset Project Registry or ARB. An offset project listed at ARB or a new Offset Project Registry will continue to operate under its originally approved crediting period, provided that ARB may extend the crediting period or the relevant deadline in section 95977(d) for one year if ARB determines that such ~~extention~~extension is necessary to provide time for re-submission of information to the new Offset Project Registry or ARB.

(m) If the applicant under section 95986 is going to designate a subdivision of its organization to provide registry services, all the requirements of section 95986 will be applied at the designated subdivision level.

(n) An approved Offset Project Registry must make itself and its personnel available for an ARB audit.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

§ 95987. Offset Project Registry Requirements.

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(b) The Offset Project Registry must make the following information publicly available for each offset project developed under a Compliance Offset Protocol:

(1) Within 10 working days of the offset project listing requirements being deemed complete in section 95975(f):

(A) Offset project name;

(B) Offset project location;

(C) Offset Project Operator and, if applicable, the Authorized Project Designee;

(D) Type of offset project;

(E) Name and date of the Compliance Offset Protocol used by the offset project;

(F) Date of offset project listing submittal and Offset Project Commencement date; and

(G) Identification if the offset project is in an initial or renewed crediting period;

(2) Within 10 working days of the ~~Offset Project Data Report being issued an Offset Verification Statement~~ Offset Project Registry making a determination of registry offset credit issuance pursuant to section 95980(b):

(A) Annual verified project baseline emissions;

(B) Annual verified GHG reductions and GHG removal enhancements achieved by the offset project;

(C) The unique serial numbers of registry offset credits issued to the offset project for the applicable Offset Project Data Report;

(D) Total verified GHG reductions and GHG removal enhancements for the offset project by Reporting Period for when an Offset Project Data Report was submitted;

(E) The final Offset Project Data Report for each Reporting Period; and

(~~E~~F) Offset Verification Statement for each year the Offset Project Data Report was verified; and

(3) Clear identification of which offset projects are listed and submitting Offset Project Data Reports using Compliance Offset Protocols.

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(d) The Offset Project Registry may provide guidance to Offset Project Operators, Authorized Project Designees, or offset verifiers for offset projects using a Compliance Offset Protocol, if there is no clear requirement for the topic in a Compliance Offset Protocol, this article, or an ARB guidance document, after consulting and coordinating with ARB.

(1) An Offset Project Registry must maintain all correspondence and records of communication with an Offset Project Operator, Authorized Project Designee, or offset verifier when providing clarifications or guidance for an offset project using a Compliance Offset Protocol.

(2) Before providing such guidance, the Offset Project Registry may request ARB to provide clarification on the topic.

(3) Any Offset Project Operator or Authorized Project Designee requests for clarifications or guidance must be documented and the Offset Project Registry response must be submitted on an ongoing monthly basis to ARB beginning with the date of approval as an Offset Project Registry.

(e) The Offset Project Registry must audit at least 10 percent of the annual full offset verifications developed for offset projects using a Compliance Offset Protocol.

(1) The audit must include the following checks:

(A) Attendance with the offset verification team on the offset project site visit;

(B) In-person or conference call attendance for the first offset verification team and Offset Project Operator or Authorized Project Designee meeting;

(C) In-person or conference call attendance to the last meeting or discussion between the offset verification team and Offset Project Operator or Authorized Project Designee;

(D) Documentation of any findings during the audit that cause the Offset Project Registry to provide guidance to, or require corrective action with, the offset verification team, including a list of issues noted during the audit and how those were resolved;

(E) A review of the detailed verification report and sampling plan to ensure that it meets the minimum requirements in sections 95977.1 and 95977.2 and documentation of any discrepancies found during the review; and

(F) An investigative review of the conflict of interest assessment provided by the verification body, which includes the following:

1. Discussions with both the lead verifier who submitted the conflict of interest assessment form and the Offset Project Operator or Authorized Project Designee to confirm the information on the conflict of interest assessment form is true, accurate, and complete;

2. An internet-based search to ascertain the existence of any previous relationship between the verification body and the Offset Project Operator or Authorized Project Designee, and if so the nature and extent; and

3. Any other follow up by the Offset Project Registry to have reasonable assurance that the information provided on the conflict of interest assessment form is true, accurate, and complete.

(2) All information related to audits of offset projects developed using a Compliance Offset Protocol must be provided to ARB within 10 calendar days of an ARB request.

(3) The audits must be selected to provide a representative sampling of geographic locations of all offset projects, representative sampling of verification bodies, representative sampling of lead verifiers, representative sampling of offset project types, and representative sampling of offset projects by size.

(4) The Offset Project Registry must provide an annual report to ARB by January 31 for its previous year's audit program of offset projects developed using Compliance Offset Protocols that includes:

(A) A list of all offset projects audited;

(B) Locations of all offset projects audited;

(C) Verification bodies associated with each offset project and names of offset verification team members;

(D) Dates of site visits;

(E) Offset Project Registry staff that conducted the audit; and

(F) Audit findings as required in section 95987(e)(1)(D) through (F).

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NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 14: Recognition of Compliance Instruments from Other Programs

§ 95990. Recognition of Early Action Offset Credits.

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(c) Criteria for Approval of Early Action Offset Credits Issued by Early Action Offset Programs. An early action offset credit may be issued an ARB offset credit pursuant to section 95990(i) if the early action offset credit results from a GHG reduction or GHG removal enhancement which:

(1) Occurred between January 1, 2005 and December 31, 2014;

(2) Is verified pursuant to section 95990(f);

(3) Results from an early action offset project that is listed or registered with an Early Action Offset Program prior to ~~January 1, 2014;~~the following:

(A) Early action offset projects developed under any of the offset quantification methodologies in sections 95990(c)(5)(A) through (D) must be listed prior to January 1, 2014;

(B) Early action offset projects developed under any of the offset quantification methodologies in sections 95990(c)(5)(E)-(F) must be listed prior to January 1, 2015.

(4) Results from an early action offset project located in the United States; and

(5) Results from the use of one of the following offset quantification methodologies and relied on the most recent version thereof at the time of offset project submittal:

(A) Climate Action Reserve U.S. Livestock Project Protocol versions 1.0 through 3.0;

(B) Climate Action Reserve Urban Forest Project Protocol versions 1.0 through 1.1;

(C) Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0; ~~and~~

(D) Climate Action Reserve Forest Project Protocol versions 2.1 and 3.0 through 3.2, if the early action offset project contributes early action offset credits into a buffer account based on its reversal risk calculated according to the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011~~.~~;

(E) Climate Action Reserve Coal Mine Methane Project Protocol versions 1.0 and 1.1; and

(F) Verified Carbon Standard 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 and Revisions to ACM0008 to Include Methane Capture and Destruction from Abandoned Coal Mines Methodology, v1.0.

(d) The following parties must register with ARB pursuant to section 95830 before ARB offset credits may be issued pursuant to section 95990(i):

(1) The Offset Project Operator or Authorized Project Designee for a forest or urban forest early action offset project that does not transition to a Compliance Offset Protocol pursuant to section 95990(k); and

(2) The Offset Project Operator or Authorized Project Designee for the following early action offset projects, except as provided in section 95990(d)(3):

(A) A forest or urban forest early action offset project that transitions to a Compliance Offset Protocol pursuant to section 95990(k);

(B) An early action offset project developed under one of the protocols identified in section 95990(c)(5)(A)~~, and~~ (C) and (E).

(3) If the Offset Project Operator or Authorized Project Designees identified in section 95990(d)(2) do not register with ARB or list the early action offset project pursuant to section 95990(e), the holder of early action offset credits may register with ARB and seek issuance of ARB offset credits pursuant to section 95990(i), as long as the holder lists the early action offset project pursuant to section 95990(e) and provides ARB with the attestations required pursuant to section 95990(h)(6).

(e) Listing of Early Action Offset Projects. Before ARB can evaluate conflict of interest and any verification related information submitted pursuant to

section 95990(f), and issue ARB offset credits pursuant to section 95990(i):

(1) The following parties must submit the information listed in section 95990(e)(2) to ARB:

(A) The Offset Project Operator or Authorized Project Designee for a forest or urban forest early action offset project that does not transition to a Compliance Offset Protocol pursuant to section 95990(k); and

(B) The Offset Project Operator or Authorized Project Designee for the following early action offset projects, except as provided in section 95990(e)(1)(C);

1. A forest or urban forest early action offset project that transitions to a Compliance Offset Protocol pursuant to section 95990(k);

2. An early action offset project developed under one of the protocols identified in section 95990(c)(5)(A), ~~and~~ (C) and (E).

(C) If the Offset Project Operator or Authorized Project Designees identified in section 95990(e)(1)(B) do not register with ARB pursuant to section 95990(d) or list the early action offset project, the holder of early action offset credits may list the early action offset credit by submitting the information listed in section 95990(e)(2) and seek issuance of ARB offset credits pursuant to section 95990(i), as long as the following conditions are met:

1. The holder registers with ARB pursuant to section 95990(d) and provides ARB with the attestations required pursuant to section 95990(h)(6); and

2. The holder has made at least one written request to the Offset Project Operator or Authorized Project Designee to confirm that the Offset Project Operator or Authorized Project Designee will not list the applicable early action

reporting periods for the early action offset project, and has provided proof of this request, and response, or at least 30 days has passed since the request to ARB.

(2) The parties identified in section 95990(e)(1) must submit the following information to ARB:

(A) Early action offset project name;

(B) Early action offset project location;

(C) Offset Project Operator, or if applicable, the Authorized Project Designee;

(D) Name and date of protocol used by the early action offset project, including, if applicable, a version number;

(E) Date of early action offset project listing or registration date and Offset Project Commencement Date; and

(F) The name of any verification bodies associated with the early action offset project under the Early Action Offset Program.

(G) 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 destruction event may be considered an independent project.

(3) The parties identified in section 95990(e)(1) may submit one or more early action reporting period(s) for the early action offset project for listing. The parties are not required to list all early action reporting periods associated with the early action offset project.

(43) The Early Action Offset Program must make the following information available on a publicly available website and clearly indicate which early action offset projects and ~~Offset Project Data Report years~~early action reporting periods qualify for early action under this article:

(A) Early action offset project name;

(B) Early action offset project location;

(C) Offset Project Operator, or if applicable, the Authorized Project Designee;

(D) Name and date of protocol used by the early action offset project, including, if applicable, a version number;

(E) Date of early action offset project listing or registration date and Offset Project Commencement Date; and

(F) The name of any verification bodies associated with the early action offset project.

(f) Regulatory Verification of Early Action Offset Credits. Any early action offset credit issued by an Early Action Offset Program must be verified under the following requirements before being issued an ARB offset credit pursuant to section 95990(i):

(1) The project must be verified by an ARB-accredited verification body that meets the accreditation requirements in section 95978. The verification body performing regulatory verification pursuant to this section must be different than anyone verification body that conducted offset verification services for the early action offset project under the Early Action Offset Program. The offset verification team must include an offset project specific verifier for the applicable offset project type.

(2) Conflict of interest must be assessed against parties identified pursuant to section 95990(g) and the conflict of interest assessment must meet the requirements of section 95979.

(3) A verification body must conduct a desk review for each ~~Offset Project Data Report year~~early action reporting period eligible and applicable pursuant to section 95990(c)(1) for each early action offset project that generates early action offset credits under the quantification methodologies listed in section 95990(c)(5), unless the Offset Project Operator, Authorized Project Designee, or holder(s) follows the provisions in section 95990(f)(3)(G). The desk review of all early action reporting periods~~Offset Project Data Reports for years~~ eligible and applicable pursuant to section 95990(c)(1) for each early action offset project may be applied as one single desk review. A desk review pursuant to section 95990(f)(3) may only be conducted once for

each early action reporting period. The desk review must include the following:

(A) Review of the early action offset project original documentation, including the Early Action Verification Reports and Offset Verification Statements submitted to the Early Action Offset Program, to ensure that the previously provided offset verification services were sufficient to render a reasonable assurance to support the issuance of early action offset credits by the Early Action Offset Program;

(B) Review and recalculation of the data checks conducted by the original~~offset~~ verification body for the Early Action Offset Program to ensure they were calculated correctly;

(C) If the verification body concludes with reasonable assurance that they concur that a positive verification statement should have been issued based on the Early Action Verification Report and the Offset Verification Statement submitted to the Early Action Offset Program for the applicable ~~Offset Project Data Report year~~early action reporting period, the verification body must submit the attestation in section 95990(f)(3)(D) to ARB, and provide ARB with a report detailing the findings of the desk review. The Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, must submit the related early action reporting periods for the early action offset project for listing pursuant to section 95990(e) prior to the verification body submitting the attestation or any findings pursuant to section 95990(k).

(D) The verification body must attest, in writing, to ARB as follows: "I certify under penalty of perjury under the laws of the State of California that I have conducted a desk review in accordance with the requirements of section 95990(f)(3) and concur with the issuance of a positive verification statement based on the Early

Action Verification Report and Offset Verification Statement that was submitted to the Early Action Offset Program for the applicable ~~Offset Project Data Report year~~early action reporting period."

(E) For each early action offset project the Offset Project Operator or Authorized Project Designee or the Early Action Offset Program must provide the Early Action Verification Report(s) for all ~~years~~early action reporting periods eligible and applicable pursuant to section 95990(c)(1) to the offset verification team to assist in offset verification services and desk review.

(F) ARB will review the desk review findings submitted by the desk review verification body and determine whether to accept or reject the findings. ARB will consult with the OPO, APD, or holder(s), and the verification body, as needed when making its determination. ARB will notify the verification body, Offset Project Operator, Authorized Project Designee, or holder(s) that listed the early action offset project of its determination. If ARB does not agree with a positive desk review finding, ARB will require that the reporting information provided by the Offset Project Operator or Authorized Project Designee to the original verification body be subject to full offset verification services pursuant to section 95990(f)(6).

(G) If the desk review verification body is unable to obtain the original verification body's data checks calculations or information used by the original verification body required to be reviewed pursuant to section 95990(f)(3)(A) or (B), the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, may opt out of the desk review and conduct full offset verification services pursuant to section 95990(f)(6).

(4) If during the desk review performed pursuant to section 95990(f)(3) the verification body cannot conclude with reasonable assurance that a

positive verification statement should have been issued based on the Early Action Verification Report and the Offset Verification Statement submitted to the Early Action Offset Program for the applicable ~~Offset Project Data Report year~~early action reporting period then the verification body must prepare a report for ARB and explain the reasons for this conclusion.

(5) ARB will review the information submitted by the verification body pursuant to section 95990(f)(4) and may request additional information from, and consult with, the Early Action Offset Program or the verification body as necessary.

(6) If ARB finds that the ~~Offset Project Data Report~~GHG reductions or removal enhancements reported to the Early Action Offset Program for a given early action reporting period should not have been issued a positive verification statement after reviewing the information submitted ~~in section 95990(f)(5)~~by the desk review verification body, the ~~Offset Project Data Report~~reporting information provided by the Offset Project Operator or Authorized Project Designee to the original verification body must be verified and full offset verification services pursuant to sections 95977.1 and any additional verification requirements in the applicable protocol identified in section 95990(c) must be conducted. The full offset verification services will be conducted based on the early action quantification methodology under which the OPO or APD of the early action offset project originally reported. The Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, may determine to not move forward with the full offset verification services and the early action offset credits would no longer be eligible to transition to ARB offset credits. If the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, determine to move forward with the full offset verification services, t~~T~~he ~~O~~offset verification services for each ~~Offset Project Data Report year~~early action reporting period may be done by the same verification body that

performed the desk review and may be applied as one single offset verification service and meet the following requirements:

(A) If the early action offset project is still in operation, the verification body must conduct a site visit as required in section 95977.1(b)(3)(D).

(B) If the early action offset project is no longer in operation, the verification body must conduct a desk review of the original documentation to confirm any previous verification findings related to the types of offset verification services required in section 95977.1(b)(3)(D).

(C) The sampling plan in section 95977.1(b)(3)(G) must cover all serialized early action offset credits issued to the early action offset project for all years eligible and applicable pursuant to section 95990(c)(1);

(D) The data checks in section 95977.1(b)(3)(L) must include checks across the sources identified in the sampling plan, covering all serialized early action offset credits issued to the early action offset project for all years eligible and applicable pursuant to section 95990(c)(1); and

(E) The verification body must submit an Offset Verification Statement pursuant to section 95977.1(b)(3)(R) to ARB covering all serialized early action offset credits issued to the early action offset project for all ~~years~~early action reporting periods eligible and applicable pursuant to section 95990(c)(1). For non-forestry offset projects, the verification body may submit a Positive, Qualified Positive, or Adverse Offset Verification Statement. Forestry Offset projects may only receive a Positive or Adverse Offset Verification Statement.

(7) Once ARB offset credits have been issued for ~~an Offset Project Data Report~~an early action reporting period pursuant to section 95990(i) subsequent offset verification services provided for additional ~~Offset~~

~~Project Data Reports~~early action reporting periods for the same early action offset project will not trigger a desk review of those ~~Offset Project Data Reports~~early action reporting periods for which ARB offset credits have already been issued pursuant to section 95990(i).

(g) Conflict of Interest Requirements for Early Action. For each ~~Early Action Verification Report~~early action reporting period for which ~~that~~ a verification body ~~reviews~~provides regulatory verification pursuant to section 95990(f), the verification body must assess conflict of interest according to the following requirements against each party identified in section 95990(g)(2). The conflict of interest assessment for each ~~Early Action Verification Report~~early action reporting period must be submitted to ARB before ARB issues an ARB offset credit pursuant to section 95990(i). Conflict of interest self-evaluations for multiple early action reporting periods for one early action offset project may be combined into one evaluation. The Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, must submit the related early action reporting periods for the early action offset project for listing pursuant to section 95990(e), and the listing must be approved, prior to the verification body submitting the conflict of interest assessment pursuant to this section.

(1) The verification body is subject to the conflict of interest requirements in section 95979.

(2) The conflict of interest requirements in section 95979 must be assessed against the following parties at the time that offset verification services are conducted pursuant to section 95990(f):

(A) The Offset Project Operator ~~or~~and Authorized Project Designee or holder(s), if applicable, for the project; and

(B) Any party that holds greater than 30 percent of the early action offset credits issued to an early action offset project for each individual ~~Early Action Verification Report~~early action reporting period reviewed as part of offset verification services conducted pursuant to section 95990(f).

(h) Issuance of ARB Offset Credits for Early Action. ARB will issue ARB offset credits pursuant to section 95990(i) for early action if the following requirements are met:

(1) The early action offset credits meet the requirements of section 95990(c);

(2) The GHG reduction or GHG removal enhancement occurred by December 31, 2014;

(3) The GHG reduction or GHG removal enhancement was determined to meet the requirements for regulatory verification pursuant to section 95990(f) and verification under the Early Action Offset Program was completed with the submittal of an Offset Verification Statement to an Early Action Offset Program by September 30, 2015 for GHG reductions or GHG removal enhancements eligible to be issued ARB offset credits;

(4) The early action offset project has been listed pursuant to section 95990(e); and

(5) The following parties must submit the attestations listed in section 95990(h)(6) to ARB:

(A) The Offset Project Operator or Authorized Project Designee for a forest or urban forest early action offset project that does not transition to a Compliance Offset Protocol pursuant to section 95990(k); and

(B) The Offset Project Operator or Authorized Project Designee for the following early action offset projects, except as provided in section 95990(h)(5)(C):

1. A forest or urban forest early action offset project that transitions to a Compliance Offset Protocol pursuant to section 95990(k);

2. An early action offset project developed under one of the protocols identified in section 95990(c)(5)(A), ~~and~~ (C) and (E).

(C) If the Offset Project Operator or Authorized Project Designees identified in section 95990(h)(5)(B) do not register with ARB pursuant to section 95990(d) and list the early action offset project pursuant to section 95990(e), the holder of early action offset credits may seek issuance of ARB offset credits pursuant to section 95990(i), as long as the holder provides ARB the attestations required pursuant to section 95990(h)(6).

(6) The parties identified in section 95990(h)(5) must submit the following information to ARB:

(A) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury under the laws of the State of California the GHG reductions and GHG removal enhancements for [project] from [date] to [date] have been measured in accordance with the [appropriate Early Action Offset Program offset protocol] and all information required to be submitted to ARB is true, accurate, and complete;";

(B) Attest, in writing, to ARB as follows:

"I understand I am voluntarily participating in the California Greenhouse Gas Cap-and-Trade Program under title 17, article 5, and by doing so, I am now subject to all regulatory requirements and enforcement mechanisms of this program and subject myself to the jurisdiction of California as the exclusive venue to resolve any and all disputes;"; and

(C) Attest in writing to ARB as follows:

"I understand that the offset project activity and the implementation of the offset project must be in accordance with all applicable local, regional, and national environmental and health and safety regulations that apply based on the offset project location. I understand that offset projects are not eligible to receive ARB offset credits for GHG reductions or GHG

removal enhancements that are not in compliance with the requirements of this Article."

(7) An ARB offset credit may not be issued for an early action offset credit that has been retired, canceled, used to meet a surrender obligation, used to meet a voluntary commitment, or used to meet any GHG mitigation requirements in any voluntary or regulatory system.

(i) Process for Issuance of ARB Offset Credits for Purposes of Early Action. ARB will issue an ARB offset credit that meets the requirements of section 95990(h) in the amount calculated pursuant to section 95990(i)(1) :

(1) ARB offset credits will be issued according to the following schedule:

(A) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve Urban Forest Project Protocol versions 1.0 through 1.1;

(B) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0;

(C) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve U.S. Livestock Project Protocol versions 1.0 through 3.0; and

(D) ARB offset credits will be issued for early action offset credits generated under Climate Action Reserve Forest Project Protocol version 2.1 and versions 3.0 through 3.2, pursuant to the following:

1. If any ARB offset credits are being issued to an early action forest offset project pursuant to this section, ARB will notify the Early Action Offset Program of the quantity of early action offset credits that must be removed or canceled~~transfer all of the early action offset credits in~~ from its buffer account for forest projects for that project ~~to ARB by removing the early action offset credits,~~ such that they are

no longer available on the Early Action Offset Program's system.

a. ~~For vintages 2001-2004 early action offset credits in the Early Action Offset Program buffer account for forest projects transferred for the early action forest offset project, ARB will create a series of unique serial numbers that identify them as being from these vintage years.~~The early action offset credits being removed or canceled from the Early Action Offset Program's buffer account for forest projects must meet the criteria of this section. Early action offset credits that do not meet the criteria of this section may not be used to meet ARB's Forest Buffer Account requirements.

b. ~~Vintage 2001-2004 serial numbers may only reside in the Forest Buffer Account and will only be retired by ARB in the event of a project termination pursuant to section 95983(d). These vintages will not be able to count towards the contribution to ARB's Forest Buffer Account pursuant to this section.~~If ARB offset credits were placed in the Forest Buffer Account for purposes of transitioning early action offset credits to ARB offset credits, and the early action offset credits were removed or canceled from the Early Action Offset Program's buffer account for forest projects pursuant to sections 95990(i)(1)(D)(1.)(b.)(i.) or (ii.), ARB will remove or cancel the ARB offset credits from the Forest Buffer Account so that they may be transferred permanently to the Early Action Offset Program's buffer account for forest offset projects:

i. The early action offset credits did not meet the criteria in section 95990(c); or

ii. The early action offset credits removed from the Early Action Offset Program's buffer account for forest projects were removed in excess of the amount of early action offset credits required by this section.

2. A specified number of the issued ARB offset credits must be placed in the Forest Buffer Account ~~in the amount determined by the project-specific risk rating calculation in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011~~ for each ~~Offset Project Data Report year~~early action reporting period eligible and applicable pursuant to section 95990(c)(1) using the following equation:~~.~~

$$ARB_{Buffer} = ARB_{Issue} \times Max[RR_{EAOP}, RR_{COP}]$$

Where:

"ARB_{Buffer}" is the number of ARB offset credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account;

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in sections 95990(i)(1)(D)(3.)(a), (b.) or (c.) below, as applicable;

"Max" is the larger of the two values [RR_{EAOP}, RR_{COP}];

"RR_{EAOP}" is the reversal risk rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits placed in the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for an early action reporting period; and

"RR_{COP}" is the reversal risk rating percentage that must be applied to an early action forest offset project pursuant to the project-specific reversal risk rating calculation in the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 for an early action reporting period.

a. ARB will calculate the reversal risk rating percentage for RR_{COP} for the early action reporting period for the early action offset project according to the requirements in the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011.

b. When calculating the reversal risk rating percentage using the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, ARB will use the maximum value for each risk category in the Compliance Offset Protocol unless the original early action verification included a review of the criteria for determining the risk and verified the requirements for calculating the risk category.

c. Qualified Conservation Easements cannot be retroactively applied to the reversal risk rating percentage calculations for the purposes of early

action. Once the forest project transitions to a Compliance Offset Protocol pursuant to section 95990(k), it may use a Qualified Conservation Easement to reduce its reversal risk rating on a forward basis.

3. ~~If the Offset Project Operator or Authorized Project Designee registers and lists the early action offset project pursuant to sections 95990(d) and (e) and is seeking issuance of ARB offset credits for an Offset Project Data Report year~~ ARB will determine the number of ARB offset credits that ~~will~~may be issued to the Offset Project Operator, ~~or~~ Authorized Project Designee, or holder(s), if applicable, for each early action reporting period for which ARB offset credits are issued as follows:

   a. If the following condition applies, and no early action offset credits have yet been canceled or retired from the Early Action Offset Program's buffer account for forest projects for the early action reporting period, then ARB will issue one ARB offset credit for each early action offset credit that meets the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits, plus an amount of ARB offset credits equal to the associated credits transferring over from the Early Action Offset Program's buffer account for forest projects, for an early action reporting period:

$$If: RR_{EAOP} \geq RR_{COP}$$

$$Then: ARB_{Issue} = \frac{ARB_{Request}}{(1 - RR_{EAOP})}$$

~~$EAOP_{Buffer} \geq EAOC_{Issue} \times RR_{COP}$~~

Where:

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period, based on the amount of ARB offset credits for which the party is seeking issuance;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for an early action reporting period;

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for each early action reporting period; and

~~"$EAOP_{Buffer}$" is the total number of early action offset credits in the Early Action Offset Program's buffer account for forest projects that meet the requirements~~

~~of section 95990(h) and are being transferred to ARB for the applicable Offset Project Data Report;~~

~~"$EAOC_{Issue}$" is the total number of early action offset credits that meet the requirements of section 95990(h) for which the Offset Project Operator or Authorized Project Designee is seeking issuance of ARB offset credits pursuant to this section for the applicable Offset Project Data Report;~~

"RR_{COP}" is the reversal risk rating percentage that must be applied ~~for~~to the early action forest offset project pursuant to the project-specific reversal risk rating calculation in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 for an early action reporting period.~~;~~

i. The Early Action Offset Program must retire or cancel early action offset credits from its buffer account for forest projects for the early action reporting period equal to the following:

$$EAOP_{BufferRetire} = ARB_{Issue} \times RR_{EAOP}$$

Where:

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for the early action reporting period;

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance

Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)(3.)(a.) above; and

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for each early action reporting period.

ii. ARB will place ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, according to the following for each early action reporting period:

$$ARB_{Holding} = ARB_{Issue} - ARB_{Buffer}$$

Where:

"$ARB_{Holding}$" is the number of ARB offset credits to be placed into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, seeking

issuance of ARB offset credits for an early action reporting period;

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)(3.)(a.) above; and

"ARB_{Buffer}" is the number of ARB Offset Credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account as calculated in 95990(i)(1)(D)(2.) above.

b. If the ~~amount of early action offset credits being transferred to ARB from the~~ Early Action Offset Program's ~~buffer account for forest projects~~reversal risk rating percentage is less than the reversal risk rating calculated using the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, and no early action offset credits have yet been canceled or retired from the Early Action Offset Program's buffer account for forest projects for the early action reporting period, the following equation will determine~~does not cover~~ the number of ARB offset credits to be ~~placed in the Forest Buffer Account~~

issued for each early action reporting period, the following applies:

~~*If: $EAOP_{Buffer} < EAOC_{Issue} \times RR_{COP}$*~~

~~*Then: $ARB_{Issue} = EAOC_{Issue} - |(EAOC_{Issue} \times RR_{COP}) - EAOP_{Buffer}|$*~~

If: $RR_{EAOP} < RR_{COP}$

$$Then: \ ARB_{Issue} = \frac{ARB_{Request}}{(1 - RR_{EAOP})}$$

Where:

"ARB_{Issue}" is the total number of ARB offset credits ~~that will be~~ issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by ~~to~~ the Offset Project Operator, ~~or~~ Authorized Project Designee, or holder(s) for ~~the applicable Offset Project Data Report~~an early action reporting period, based on the amount of ARB offset credits for which the party is seeking issuance;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for an early action reporting period;

~~"$EAOC_{Issue}$" is the total number of early action offset credits that meet the requirements of section 95990(h) for which the Offset Project Operator or Authorized Project Designee is seeking issuance of~~

~~ARB offset credits pursuant to this section for the applicable Offset Project Data Report;~~

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for each early action reporting period; and

"RR_{COP}" is the reversal risk rating percentage that must be applied ~~for~~to the early action forest offset project pursuant to the project-specific reversal risk rating calculation in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 for an early action reporting period.;

~~"$EAOP_{Buffer}$" is the total number of early action offset credits in the Early Action Offset Program's buffer account for forest projects that meet the requirements of section 95990(h) and are being transferred to ARB for the applicable Offset Project Data Report;~~

i. The Early Action Offset Program must retire or cancel early action offset credits from its buffer account for forest projects for the early action reporting period equal to the following:

$$EAOP_{BufferRetire} = ARB_{Issue} \times RR_{EAOP}$$

Where:

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for an early action reporting period;

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)(3.)(b.) above; and

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for an early action reporting period.

ii. ARB will place ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, according to the following, for each early action reporting period:

$$ARB_{Holding} = ARB_{Issue} - ARB_{Buffer}$$

Where:

"$ARB_{Holding}$" is the number of ARB offset credits to be placed into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, seeking issuance of ARB offset credits for an early action reporting period;

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period as calculated in section 95990(i)(1)(D)(3.)(b.) above; and

"ARB_{Buffer}" is the number of ARB Offset Credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account as calculated in 95990(i)(1)(D)(2.) above.

c. If early action offset credits have already been canceled or removed from the Early Action Offset Program's buffer account for forest projects for an early action reporting period due to a reversal or retirement prior to issuance of ARB offset credits, the following will apply for any early action reporting period regardless of ARB's or the Early Action Offset Program's reversal risk rating calculation:

i The number of early action offset credits the Early Action Offset Program must cancel from its buffer account for forest projects for the early action reporting period is as follows:

$$EAOP_{BufferRetire} = \frac{\frac{ARB_{Request}}{(1 - RR_{EAOP})}}{EAOP_{Issue}} \times EAOP_{BufferActive}$$

Where:

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for an early action reporting period;

"$EAOP_{Issue}$" is the total number of early action offset credits that were issued, for the early action reporting period by the Early Action Offset Program including early action offset credits placed in the buffer account for forest projects;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset credits for the early action reporting period;

"RR_{EAOP}" is the risk-reversal rating percentage applied by the Early Action Offset Program to calculate the number of early action offset

credits that were placed into the Early Action Offset Program's buffer account for forest projects at the time of early action offset credit issuance by the Early Action Offset Program for an early action reporting period; and

"$EAOP_{BufferActive}$" is the number of active early action offset credits remaining in the Early Action Offset Program buffer account for forest projects for the early action reporting period after the reversal or retirement.

ii The number of early action offset credits ARB will issue is as follows:

$$ARB_{Issue} = ARB_{Request} + EAOP_{BufferRetire}$$

Where:

"ARB_{Issue}" is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits requested by the Offset Project Operator, Authorized Project Designee, or holder(s) for an early action reporting period;

"$ARB_{Request}$" is the number of early action offset credits that meet the requirements of this section for which the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, are seeking issuance of ARB offset

credits for each early action reporting period; and

"$EAOP_{BufferRetire}$" is the number of early action offset credits the Early Action Offset Program will retire from its buffer account for forest projects for an early action reporting period, as calculated pursuant to section 95990(i)(1)(D)(3.)(c.)(i.) above;

iii ARB will place ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s), if applicable, according to the following for each early action reporting period:

$$ARB_{Holding} = ARB_{Issue} - ARB_{Buffer}$$

Where:

"$ARB_{Holding}$" is the number of ARB offset credits to be placed in the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) if applicable, seeking issuance of ARB offset credits for an early action reporting period;

"ARB_{Issue} is the total number of ARB offset credits issued by ARB into the Issuance Account, including the ARB offset credits to be placed into the Forest Buffer Account, for transitioning the early action offset credits

requested by the Offset Project Operator, Authorized Project Designee, or holder(s), for an early action reporting period as calculated in section 95990(i)(1)(D)(3.)(c.)(ii.) above; and

"ARB_{Buffer}" is the number of ARB Offset Credits issued for the early action reporting period to be placed in the ARB Forest Buffer Account as calculated in 95990(i)(1)(D)(2.) above.

d. When ARB requests retirement or cancellation of early action offset credits from an Early Action Offset Program's buffer account for forest projects for the purpose of placement in ARB's Forest Buffer Account, ARB will request proof from an Early Action Offset Program that it has retired the early action offset credits from its buffer account for forest offset projects. The Early Action Program must provide proof to ARB of its retirement of the early action offset credits from its buffer account for forest projects within 10 calendar days of a request by ARB.

~~4. If the holder of early action offset credits registers and lists the early action offset project pursuant to sections 95990(d) and (e), provides the attestations listed in section 95990(h)(6) to ARB, and is seeking issuance of ARB offset credits pursuant to this section for an Offset Project Data Report year, ARB will determine the number of ARB offset credits that will be issued to each holder of the original early action offset credits as follows:~~

~~a. If the following condition applies, then ARB will issue one ARB offset credit for each early action offset~~

credit for which the holder is seeking issuance of ARB offset credits:

$$EAOP_{Buffer} \geq EAOC_{Issue} \times RR_{COP}$$

Where:

"$EAOP_{Buffer}$" is the total number of early action offset credits in the Early Action Offset Program's buffer account for forest projects that meet the requirements of section 95990(h) and are being transferred to ARB for the applicable Offset Project Data Report;

"$EAOC_{PIssue}$" is the total number of early action offset credits that meet the requirements of section 95990(h) that would qualify to be issued ARB offset credits pursuant to this section for the applicable Offset Project Data Report;

"RR_{COP}" is the percentage that must be applied for the early action forest offset project pursuant to the project-specific risk rating calculation in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011;

b. If the amount of early action offset credits being transferred to ARB from the Early Action Offset Program's buffer account for forest projects does not cover the number of ARB offset credits to be placed in the Forest Buffer Account, the following applies:

$$If: EAOP_{Buffer} < EAOC_{PIssue} \times RR_{COP}$$

$$Then: ARB_{HIssue} = EAOC_{HIssue} - |(EAOC_{HIssue} \times RR_{COP}) - (EAOC_{HIssue} \times RR_{EAP})|$$

~~Where:~~

~~"$EAOP_{Buffer}$" is the total number of early action offset credits in the Early Action Offset Program's buffer account for forest projects that meet the requirements of section 95990(h) and are being transferred to ARB for the applicable Offset Project Data Report;~~

~~"$EAOC_{PIssue}$" is the total number of early action offset credits that meet the requirements of section 95990(h) that would qualify to be issued ARB offset credits pursuant to this section for the applicable Offset Project Data Report;~~

~~"ARB_{HIssue}" is the total number of ARB offset credits that will be issued to the holder of early action offset credits seeking issuance of ARB offset credits pursuant to this section for the applicable Offset Project Data Report;~~

~~"$EAOC_{HIssue}$" is the total number of early action offset credits that meet the requirements of section 95990(h) for which the holder of early action offset credits is seeking issuance of ARB offset credits pursuant to this section for the applicable Offset Project Data Report;~~

~~"RR_{COP}" is the percentage that must be applied for the early action forest offset project pursuant to the project-specific risk rating calculation in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011;~~

~~"RR_{EAP}" is the percentage that was calculated and applied for the early action forest offset project pursuant to the project-~~

~~specific risk rating calculation in the applicable early action protocol;~~

~~5~~4. If there is an unintentional reversal for any early action forest offset project, even after it transitions to ARB's Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, the provisions in section 95983(b) and (d) apply.

~~6~~5. If there is an intentional reversal for any early action forest offset project, even after it transitions to ARB's Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, the provisions in section 95983(c) and (d) apply.

(E) One ARB offset credit will be issued for one early action offset credit generated under Climate Action Reserve Coal Mine Methane Project Protocol versions 1.0 and 1.1;

(F) ARB offset credits will be issued for early action offset projects generated under Verified Carbon Standard VRM0001 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 Revisions to ACM0008 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 $BE_{Use,y}$ in ACM0008); or
2. No ARB offset credits will be issued for early action reporting periods that included emissions from the production of power, heat or supply to gas grid replaced by the project activity in the baseline (identified as $BE_{Use,y}$ in ACM0008); and

(GE) If an early action offset project is issued ARB offset credits pursuant to section 95990(i)(1)(D) and transitions from Climate Action Reserve Forest Project Protocol version 2.1 to Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 pursuant to section 95990(k) the early action offset project may calculate its project baseline pursuant to section 95990(k)(1)(D) and use the following method to determine if it could qualify for additional early action offset credits:

1. Based on the project baseline calculated in section 95990(k)(1)(D), the early action offset project must calculate and sum the net GHG emission reductions and GHG removal enhancements it achieves following all the provisions of the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 and the requirements in this article, from the date of offset project commencement under the Early Action Offset Program through the date the early action offset project applies for transition pursuant to section 95990(k).
2. The early action offset project must subtract the number of early action offset credits issued by the Early Action Offset Program for the period from the date of offset project commencement through the time the early action offset project applies for transition pursuant to section 95990(k) from the number of sum determined pursuant to section 95990(i)(EF)(1.):
    a. If the difference is positive, ARB will issue ARB offset credits equivalent to the difference at the time of offset project transition pursuant to section 95990(k) for the timeframe specified in section 95990(i)(1)(EF)(1.) to the Offset Project Operator or Authorized Project Designee.

b. If the difference is negative, ARB will only issue ARB offset credits pursuant to section 95990(i)(D)(1.) for the timeframe specified in section 95990(i)(1)(~~E~~F)(1.)

3. Section 95990(i)(1)(F) does not apply to holders of early action offset credits.

(2) ARB will notify the Early Action Offset Program within 10 calendar days of ARB's determination of issuance of ARB offset credits pursuant to this section.

(3) Early action offset credits must be permanently removed or canceled by the Early Action Offset Program within 10 calendar days of ARB notification, such that the early action offset credits are no longer available for transaction on the Early Action Offset Program registry system.

(4) Not later than 15 calendar days after ARB issues an ARB offset credit for purposes of early action, ARB will notify the Offset Project Operator, Authorized Project Designee, and holder(s) of the original early action offset credits, if applicable, of the issuance.

(j) Registration and Transfer of ARB Offset Credits for Purposes of Early Action. An ARB offset credit issued pursuant to section 95990(i) will be registered by creating a unique ARB serial number. ARB will transfer the serial numbers into Holding Accounts as follows within 15 working days of the notice of issuance pursuant to section 95990(i)(4), unless otherwise required in section 95990(i)(1)(D):

(1) If the Offset Project Operator or Authorized Project Designee ~~registered the early action offset project pursuant to section 95990(d), lists the early action offset project pursuant to section 95990(e), provides ARB the attestations pursuant to section 95990(h)(6), and is issued ARB offset credits pursuant to section 95990(i),~~ was issued additional ARB offset credits pursuant to section 95990(i)(1)(F)(2.)(a.) ARB will transfer the ARB offset credit into the Holding Account of the Offset Project Operator or Authorized Project Designee.

(2) ~~If the holder registered the early action offset project pursuant to section 95990(d), lists the early action offset project pursuant to section 95990(e), provides ARB the attestations pursuant to section 95990(h)(6), and is issued ARB offset credits pursuant to section 95990(i),~~ For an ARB offset credit issued pursuant to section 95990(i)(1)(A) through (E) ARB will transfer the ARB offset credits into the Holding Account of the Offset Project Operator, Authorized Project Designee, or holder(s) of the early action offset credits.

(A) The Offset Project Operator, Authorized Project Designee, or holder(s) must prove ownership of the original early action offset credits, including the original serial numbers issued by the Early Action Offset Program, and submit a request for issuance to ARB for the issuance of ARB offset credits, before ARB will transfer the ARB offset credits into the Holding Account. Offset Project Operators, Authorized Project Designees, and Forest Owners may also be considered holders if they can prove ownership of the original early action offset credits.

(B) Before any party is issued ARB offset credits into a Holding Account, the party must be registered with ARB pursuant to section 95830 and be approved for a Holding Account.

(C) ARB will make publicly available on its webpage which early action offset credits qualify to be issued ARB offset credits based on the early action reporting period in which the early action offset credits were issued.

(k) Transition of Early Action Offset Projects to the Compliance Program.

(1) Early Action Offset Project Transition to ARB Compliance Offset Protocols. Early action offset projects must transition to ARB Compliance Offset Protocols no later than February 28, 2015, by submitting listing information required pursuant to section 95975 to ARB or an Offset Project Registry and having that listing approved:

(A) Early action offset projects using Climate Action Reserve U.S. Livestock Project Protocol versions 1.0 through 3.0 must use and meet all the requirements in Compliance Offset Protocol Livestock Projects, October 20, 2011;

(B) Early action offset projects using Climate Action Reserve Urban Forest Project Protocol versions 1.0 through 1.1 must use and meet all the requirements in Compliance Offset Protocol Urban Forest Projects, October 20, 2011;

(C) Early action offset projects using Climate Action Reserve U.S. Ozone Depleting Substances Project Protocol version 1.0 must use and meet all the requirements in Compliance Offset Protocol Ozone Depleting Substances Projects, October 20, 2011;

(D) Early action offset projects using Climate Action Reserve Forest Project Protocol version 2.1 must use and meet all the requirements in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011. At the time of transition the early action offset project must calculate its project baseline according to all the provisions in Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 and the requirements in this article over the period of time from the date of offset project commencement under the Early Action Offset Program to the date the early action offset project applies for transition pursuant to section 95990(k), plus one-hundred years. This project baseline will remain valid for the duration of the offset project life. Registry offset credits and ARB offset credits issued for the first Reporting Period after the early action offset project is listed pursuant to section 95975 using the Compliance Offset Protocol U.S. Forest Projects, October 20, 2011, will only be for the increased carbon stocks beyond what was already issued early action offset credits in the last year before the early action offset

project transitioned to a Compliance Offset Protocol pursuant to this section.;

(E) Early action offset projects using Climate Action Reserve Forest Project Protocol versions 3.0 through 3.2 must use Compliance Offset Protocol U.S. Forest Projects, October 20, 2011 and subtract from the project baseline any carbon stocks from any optional pools that are excluded in the Compliance Offset Protocol beginning with the last reporting period under the Early Action Offset Program. Decreases will not constitute a reversal.; and

(F) Early action offset projects using Climate Action Reserve Coal Mine Methane Project Protocol versions 1.0 and 1.1 must use and meet all the requirements in Compliance Offset Protocol Mine Methane Capture Projects, [DATE].

(2) Crediting Periods for Early Action Offset Projects. When an early action offset project transitions to a Compliance Offset Protocol pursuant to section 95990(k)(1), it will begin an initial crediting period. The initial crediting period will begin with the date that the first verified GHG emission reductions or GHG removal enhancements occur using a Compliance Offset Protocol approved pursuant to section 95971.

(3) Listing Requirements for Transition of Early Action Offset Projects. At the time an early action offset project transitions to a Compliance Offset Protocol pursuant to section 95990(k)(1), the Offset Project Operator or Authorized Project Designee must:

(A) Meet the requirements for offset projects pursuant to section 95973; and

(B) List the offset project pursuant to section 95975.

(C) To transition an early action offset project to the ARB compliance offset program, the offset project must be listed with ARB or an Offset Project Registry by February 28, 2015, but has until September 30, 2015 to complete the verification of

GHG reductions and GHG removal enhancements ~~pursuant to section 95990(f)~~ under the Early Action Offset Program that were achieved in 2014 with the submittal of an Offset Verification Statement to the Early Action Offset Program. These GHG reductions and GHG removal enhancements are eligible for early action offset credits.

(4) After an early action offset project lists with ARB pursuant to section 95990(k)(3), it must meet the following requirements:

(A) Monitoring, reporting, and record retention requirements pursuant to section 95976;

(B) GHG reduction and GHG removal enhancement verification requirements pursuant to sections 95977 through 95978;

(C) Be issued a registry offset credit pursuant to section 95980.1 or an ARB offset credit pursuant to section 95981.1 for any GHG reductions or GHG removal enhancements it achieves.

(5) ARB will not issue ARB offset credits after August 31, 2016 for any GHG reductions or GHG removal enhancements achieved through 2014 and issued early action offset credits by an Early Action Offset Program.

(l) An ARB offset credit issued pursuant to section 95990(i) may be invalidated pursuant to section 95985 as follows:

(1) ~~ARB Offset Credits from Non-Sequestration Offset Projects.~~ An ARB offset credit issued to~~from~~ a non-sequestration project or an urban forest project, or a U.S. forest offset project issued on or after January 1, 2014, or the effective date of this regulation, may be invalidated pursuant to sections 95985(a) through (h) and section 95985(j) and as follows:

(A) If an Offset Project Operator or Authorized Project Designee registers and lists the early action offset project pursuant to sections 95990(d) and (e), and submits the attestations to ARB pursuant to section 95990(h)(6)~~, and was issued offset credits~~

~~pursuant to section 95990(i)~~ and the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2), the provisions in sections 95985(h)(1)(C)(1.) through (3.) and sections 95985(h)(2)(B)(1.) through (3.) still apply to the Offset Project Operator; or

(B) If the holder of early action offset credits registers and lists the early action offset project pursuant to sections 95990(d) and (e), submits the attestations to ARB pursuant to section 95990(h)(6), and was issued ARB offset credits pursuant to section 95990(i) and the party identified in section 95985(e)(2) is no longer in business pursuant to section 95101(h)(2), the provisions in sections 95985(h)(1)(C)(1.) through (3.) and sections 95985(h)(2)(B)(1.) through (3.) apply to the holder that was issued ARB offset credits pursuant to section 95990(i) and not the Offset Project Operator.

(2) ~~ARB Offset Credits from Forest Offset Projects.~~ An ARB offset credit issued to~~from~~ a U.S. forest offset project prior to January 1, 2014, may be invalidated pursuant to sections 95985(a) through (g) and sections 95985(i) and (j).

(3) For an early action offset project developed under one of the quantification methodologies in sections 95990(c)(5)(A), (B), (D), or (E) the invalidation timeframe will remain at eight years, unless one of the following applies and are met to reduce the statute of limitations to three years:

(A) If an Offset Project Operator or Authorized Project Designee transitions an early action offset project to a Compliance Offset Protocol pursuant to section 95990(k):

1. An ARB-accredited verification body must verify a subsequent Offset Project Data Report generated under a Compliance Offset Protocol;

2. The ARB-accredited verification body must be a different verification body than the one that conducted any regulatory verification services of the early action offset project pursuant to section 95990(f) or that verified the early action offset program under the Early Action Offset Program; and

3. The new ARB-accredited verification body must verify the subsequent Offset Project Data Report within three years of the date of ARB offset credit issuance; or

(B) If an Offset Project Operator or Authorized Project Designee does not transition an early action offset project to a Compliance Offset Protocol pursuant to section 95990(k), or the Offset Project Operator or Authorized Project Designee chooses to reduce the invalidation timeframe prior to the verification of a subsequent Offset Project Data Report being verified pursuant to section 95990(l)(3)(A)(1.) above:

1. An ARB-accredited verification body must conduct full offset verification services based on the original data reports and/or reporting information submitted to the Early Action Offset Program for the original offset verification conducted under the Early Action Offset Program. The full offset verification services must be in addition to any regulatory verification services conducted for the early action offset project pursuant to section 95990(f);

2. The ARB-accredited verification body must be a different verification body than the one that conducted any regulatory verification services of the early action offset project pursuant to section 95990(f) or that verified the early action offset program under the Early Action Offset Program; and

3. The new ARB-accredited verification body must complete the full offset verification services, by submitting an Offset Verification Statement, within three years following the

issuance of ARB offset credits as a result of the regulatory verification services performed pursuant to section 95990(f). The full offset verification services must include a site visit to the offset project location. The site visit must only be performed once for all qualifying early action reporting periods.

(4) For an early action offset project developed under the quantification methodology in sections 95990(c)(5)(C), the statute of limitations will remain at eight years, unless the following criteria are met to reduce the invalidation timeframe to three years:

(A) An ARB-accredited verification body must conduct full offset verification services based on the original data reports and/or reporting information submitted to the Early Action Offset Program for the original offset verification conducted under the Early Action Offset Program. The full offset verification services must be in addition to any regulatory verification services conducted for the early action offset project pursuant to section 95990(f);

(B) The ARB-accredited verification body must be a different verification body than the one that conducted any regulatory verification services of the early action offset project pursuant to section 95990(f) or that verified the early action offset program under the Early Action Offset Program; and

(C) The new ARB-accredited verification body must complete the full offset verification services, by submitting an Offset Verification Statement, within three years of the conclusion of the regulatory verification services performed pursuant to section 95990(f) and the full offset verification services must include a site visit to the offset project location. The site visit must only be performed once for all qualifying early action reporting periods.

(5) For all ARB offset credits issued for early action, the timeframe for the invalidation timeframe will always begin with the date the ARB offset credits are issued by ARB.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Subarticle 16: Other Provisions

§ 96022. Jurisdiction of California.

(a) Any party that participates in the Cap-and-Trade Program is subject to the jurisdiction of the State of California unless the party is subject to the jurisdiction of an External GHG ETS to which California has linked its Cap-and-Trade Program pursuant to section 95830(h) and subarticle 12.

(b) Notwithstanding section 96010, subsection 96022(a) or any other jurisdictional provision in this article, this article shall not be construed to abridge the rights and protections afforded foreign sovereigns, including the right of removal to federal court, pursuant to the Foreign Sovereign Immunities Act, Public Law 94-583, as amended and codified at 28 U.S.C. sections 1330, 1332, 1391(f), 1441(d), and 1602-1611.

(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.

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

Appendix B

CITSS User Terms and Conditions

ACCESS AGREEMENT AND TERMS OF USE FOR THE CITSS
SIGN THE BOTTOM OF THE PAGE TO INDICATE YOUR ACCEPTANCE OF THIS AGREEMENT.

Access to the Compliance Instrument Tracking System Service (CITSS) is subject to the terms and conditions set forth in this Access Agreement and Terms of Use (Agreement). You must accept this Agreement in order to access the CITSS application. Violation of this agreement may result in loss of access to CITSS and, if warranted, civil or criminal prosecution under state, provincial, or federal law.

This Agreement is between the State of California, Air Resources Board (ARB) and each registered California user of Compliance Instrument Tracking System Service (User). The Agreement sets forth the terms of use of CITSS. ARB provides User with access to the CITSS software application, for registering entities and holding compliance instrument. User understands and agrees that CITSS is provided "AS IS" and without any warranty, as set forth below in greater detail.

1. CITSS Use

1.1 ARB and WCI, Inc. hereby grant to User, and User hereby accepts, subject to the terms and conditions set forth in this Agreement, a non-exclusive and non-transferable right to access CITSS via the world-wide-web or the internet at times when the software and servers are available and operating.

1.2 User further acknowledges that it is not authorized to and may not possess or distribute any or all parts of the CITSS software, including its source codes and program components. User is not authorized to install, run or operate CITSS on User's or third-party computers or servers.

1.3 User is solely responsible for ensuring that all information, data, text, or other materials that User provides to ARB or WCI, Inc. through use of CITSS (Content) are true, accurate, and complete and comply with ARB's requirements for the compliance with the cap-and-trade program under the California Cap on Greenhouse Gas Emission and Market-Based Compliance Mechanisms (Regulation) (Title 17, California Code of Regulations (CCR), Sections 98000 et sq.).

1.4 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.

1.5 ARB has included (as part of CITSS) security features including password protection to prevent a person other than the User from obtaining access through CITSS to User's Content. User understands that these security features depend on User protecting its password from disclosure to unauthorized persons. User also understands and acknowledges that despite security measures to prohibit unauthorized access to the Content through CITSS, unauthorized access could occur and in the event it does, ARB or WCI, Inc. may not be held liable for the unauthorized release of information, data, text or other materials that have been submitted to ARB using CITSS.

1.6 ARB does not endorse or provide support for software or web-based interfaces offered by third parties for purposes of submitting data to ARB. Use of a third-party interface or software product in order to access CITSS does not relieve the user of the need to ensure that information required by the applicable Regulation has been properly submitted to ARB and received by the applicable deadline and that all certifications required for use of CITSS have been submitted.

1.7 User is responsible for maintaining a copy of all data submitted to CITSS. The loss of electronic information, data, text, or other materials during use of CITSS or the unavailability of the CITSS system does not excuse User from the requirements in the applicable Regulation.

2. CITSS User Agreement
The permission granted in Section 1 above is expressly made subject to and limited by the following restrictions, in addition to the limitations and restrictions set forth in other sections of the Agreement:

2.1 User agrees not to access CITSS by any means other than using internet browsers.

2.2 User further agrees that it shall NOT:
a. Deliberately attempt to access any data, documents, email correspondence, or programs contained on systems for which User does not have authorization;
b. Engage in activity that may harass, threaten or abuse others, or intentionally access, create, store or transmit material which may be deemed offensive, indecent or obscene, or that is illegal according to local, state, provincial, or federal law;
c. Engage in activity that may degrade the performance of CITSS;
d. Deprive an authorized user access to CITSS;
e. Obtain extra resources or login privileges beyond those authorized;
f. Circumvent CITSS security measures;
g. Violate copyright law of copyrighted material;
h. Attempt to disassemble, decompile or reverse engineer CITSS;
i. Attempt to create derivative works based on CITSS;

j. Attempt to copy, reproduce, distribute or transfer CITSS;
k. Provide access to CITSS to any third parties for any improper purpose;
l. Obtain for personal benefit, or engage in political activity, unsolicited advertising, unauthorized fund raising, or solicit performance of any activity that is prohibited by any local, state, or federal law.

2.3 User's right to access CITSS automatically terminates upon User's violation of any provisions of this Agreement.

2.4 User further agrees that it will immediately inform ARB or the CITSS administrator by emailing help@wci-citss.org or calling at 1-866-682-7561 if any of the following occurs:
a. User observes any unauthorized access or misuse of CITSS;
b. User has any reason to believe that the security of their User ID, password, or security question(s) has been compromised;
c. User has any reason to believe that weaknesses in computer security, including unexpected software or system behavior, may result in unintentional disclosure of information or exposure to security threats.

2.5 User further agrees that:
a. User will maintain the security of their CITSS User ID, password, and security questions for use of the CITSS;
b. User will not disclose their CITSS User ID, password, and security questions information to anyone;
c. User will maintain an active email account listed in the CITSS at which User can receive important notifications of changes related to User's personal information or transfers involving any general account or compliance account that User represents as a Primary Account Representative, Alternate Account Representative, Account Viewing Agent, or other CITSS User;
d. Any submission User makes using the CITSS has and will have the same legal effect as if it were made in hardcopy form certified by User's handwritten signature.

2.6 If, at any time, User determines it is no longer able or willing to abide by the terms of this Agreement, User shall immediately cease all use of the CITSS and promptly notify ARB or the CITSS administrator in writing of its determination so that ARB or the CITSS administrator may formally suspend or revoke the User's access to the CITSS.

3. Disclaimer of Warranties
EXCEPT AS REQUIRED BY APPLICABLE LAW, THIS SERVICE IS MADE AVAILABLE ON AN "AS IS" BASIS, WITHOUT WARRANTIES OF ANY KIND. ARB SPECIFICALLY DISCLAIMS ALL WARRANTIES, EXPRESS OR IMPLIED, INCLUDING, BUT NOT LIMITED TO, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE WITH RESPECT TO THE SOFTWARE, OR ANY WARRANTIES REGARDING THE CONTENTS OR ACCURACY OF THE SOFTWARE.

4. Limitation on Liability

4.1 Except to the extent required by applicable law, in no event is ARB or WCI, Inc. liable to User on any legal theory for damages of any kind arising from the use of or the inability to use the CITSS, even if ARB or WCI, Inc. has been advised of the possibility of such damages. The unavailability of, or problems with the use of CITSS, does not excuse User from the reporting and compliance deadlines in the applicable Regulation.

5. Copyright and Proprietary Information

5.1 User shall not permit any person who is not registered as a User to access the CITSS and shall not copy, reproduce or distribute, or allow any other person to copy, reproduce or distribute, the CITSS, in whole or in part, without ARB's prior written consent.

6. Term

This Agreement commences upon User's acceptance of this Agreement and access to the CITSS for the first time. The Agreement shall terminate upon User's written notification to ARB under Section 2.5 of this Agreement or upon other termination or discontinuation of User's access to the CITSS, except that Sections 3, 4 and 5 survive any termination of this Agreement. ARB reserves the right to terminate this Agreement at any time, subject to the exception that Sections 3, 4 and 5 survive any termination of this Agreement.

7. Governing Law and General Provisions

This Agreement shall be governed by and construed in accordance with the laws of the State of California. The failure of ARB to exercise or enforce any right or provision of this Agreement shall not constitute a waiver of such right or provision. If any provision of this Agreement is found by a court of competent jurisdiction to be invalid, the parties agree that the court should endeavor to give effect to the parties' intentions as reflected in the provisions, and the other provisions of the Agreement remain in full force and effect.

This Agreement is not intended to modify and cannot modify any provision in the applicable Regulation, including the California Cap on Greenhouse Gas Emission and Market-Based Compliance Mechanisms. If any part of this Agreement is found to conflict with any provision(s) in the applicable Regulation(s), the applicable Regulation(s) shall control.

This Agreement constitutes the entire agreement between User and ARB with respect to use of the CITSS. There are no understandings, agreements or representations with respect to the software program that are not specified in this Agreement.

This Agreement may only be modified in a writing signed by User and the Executive Officer of the ARB.

Appendix C: Quarterly Auction and Reserve Sale Dates

	2015	2016	2017	2018	2019	2020
Q1 Auction	Wednesday, February 18	Wednesday, February 17	Wednesday, February 22	Wednesday, February 21	Wednesday, February 20	Wednesday, February 19
Q1 Reserve Sale	Wednesday, April 1	Tuesday, March 29	Tuesday, April 4	Tuesday, April 3	Tuesday, April 2	Wednesday, April 1
Q2 Auction	Tuesday, May 19	Tuesday, May 17	Tuesday, May 16	Tuesday, May 15	Tuesday, May 14	Tuesday, May 19
Q2 Reserve Sale	Tuesday, June 30	Tuesday, June 28	Tuesday, June 27	Tuesday, June 26	Tuesday, June 25	Tuesday, June 30
Q3 Auction	Tuesday, August 18	Tuesday, August 16	Tuesday, August 15	Tuesday, August 14	Tuesday, August 20	Tuesday, August 18
Q3 Reserve Sale	Tuesday, October 6	Tuesday, October 4	Tuesday, October 3	Tuesday, October 2	Tuesday, October 8	Tuesday, October 6
Q4 Auction	Tuesday, November 17	Tuesday, November 15	Tuesday, November 14	Wednesday, November 14	Tuesday, November 19	Tuesday, November 17
Q4 Reserve Sale	Tuesday, December 29	Friday, December 30	Friday, December 29	Friday, December 28	Tuesday, December 31	Tuesday, December 29