California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

Thursday, October 20, 2011 and Friday, October 21, 2011

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

October 20, 2011
9:00 a.m.
(Spanish Interpretation Services Available October 20 Only)

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

Agenda Item #

11-8-1: Public Hearing to Consider Adoption of the Proposed California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, Including Compliance Offset Protocols

Staff will recommend that the Board take final action to adopt the proposed cap-and-trade regulation. The regulation was first presented to the Board at a public hearing held on December 16, 2010, at which the Board directed staff to make a number of modifications to the proposed regulation. The modified cap-and-trade regulation, which includes four compliance protocols, is now being brought back to the Board for final action. As part of this action, staff is also recommending, pursuant to the California Environmental Quality Act, that the Board approve staff's written responses to public comments received on the environmental analysis for the proposed regulation, and approve a proposed *Adaptive Management Plan for the Cap-and-Trade Regulation*.

11-8-2: Public Hearing to Consider Proposed Amendments to the AB 32 Cost of Implementation Fee Regulation

Staff will present to the Board proposed amendments to ARB's existing AB 32 Cost of Implementation Fee Regulation. The proposed amendments clarify requirements and regulatory language and revise definitions to conform with recently proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

October 21, 2011
8:30 a.m.

Agenda Item #

11-8-3: Public Meeting to Update the Board on Mandatory Commercial Waste Recycling

ARB staff, in coordination with CalRecycle staff, will present to the Board an informational update on Assembly Bill (AB) 341, which was recently signed by the Governor. Because AB 341 is consistent with the requirements of a proposed regulation that was originally scheduled to be considered by the Board at this meeting (the *Proposed Regulation to Reduce Greenhouse Gas Emissions by Requiring Mandatory Commercial Waste Recycling*), staff believes the proposed regulation is no longer needed and will not be presenting it to the Board for consideration. Staff from both agencies will instead present this informational update.

11-8-4: Public Hearing to Consider Proposed Amendments to the Airborne Toxic Control Measure for In-Use Diesel-Fueled Transport Refrigeration Units (TRU) and TRU Generator Sets, and Facilities Where TRUs Operate

Staff will present to the Board proposed amendments to the TRU Airborne Toxic Control Measure. The proposed amendments are designed to improve compliance rates and enforceability, restore competitive fairness, and clarify existing requirements.

11-8-5: Public Hearing to Consider 2011 Amendments to the California Reformulated Gasoline Regulations

Staff will present to the Board proposed amendments to the California Reformulated Gasoline Regulations. The proposed amendments correct drafting errors in the "California Procedures for Evaluating Alternative Specifications for Phase 3 Reformulated Gasoline Using the California Predictive Model," delete outdated regulatory provisions, amend the notification requirements for test-certified alternative gasoline formulations, and amend the restrictions on blending CARBOB with other liquids. Amendments are also being proposed to increase the flexibility, enforceability, and consistency of the regulations.

CLOSED SESSION – LITIGATION

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:

Pacific Merchant Shipping Association v. Goldstene, U.S. District Court (E.D. Cal. Sacramento), Case No. 2:09-CV-01151-MCE-EFB.

POET, LLC, et al. v. Goldstene, et al., Superior Court of California (Fresno County), Case No. 09CECG04850.

Rocky Mountain Farmers Union, et al. v. Goldstene, U.S. District Court (E.D. Cal. Fresno), Case No. 1:09-CV-02234-LJO-DLB.

National Petrochemical & Refiners Association, et al. v. Goldstene, et al., U.S. District Court (E.D. Cal. Fresno) Case No. 1:10-CV-00163-AWI-GSA.

Association of Irritated Residents, et al. v. California Air Resources Board, Superior Court of California (San Francisco County), Case No. CPF-09-509562.

Association of Irritated Residents, et al. v. U.S. E.P.A., 2011 WL 310357 (C.A.9), (Feb. 2, 2011).

California Dump Truck Owners Association v. California Air Resources Board, U.S. District Court (E.D. Cal. Sacramento) Case No. 2:11-CV-00384-MCE-GGH.

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

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

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

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.

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

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;
- 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.

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

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
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Sacramento, California 95814

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October 20, 2011

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CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER ADOPTION OF THE PROPOSED CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS REGULATION, INCLUDING COMPLIANCE OFFSET PROTOCOLS

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider adoption of the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation, including Compliance Offset Protocols (cap-and-trade program).

DATE: October 20, 2011

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 may commence at 9:00 a.m., October 20, 2011 and will continue at 8:30 a.m., on October 21, 2011. This item may not be considered until October 21, 2011. Please consult the agenda for the meeting, which will be available at least 10 days before October 20, 2011, to determine the day on which this item will be considered.

BACKGROUND:

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. On October 28, 2010, ARB released a Notice and Staff Report: Initial Statement of Reasons (ISOR) for a proposed regulation that would establish a California GHG cap-and-trade program (proposed sections 95800 to 96023, title 17, California Code of Regulations (CCR)). The ISOR, entitled *Initial Statement of Reasons: Proposed Regulation to Implement the California Cap-and-Trade Program,* and other rulemaking documents are available at ARB's rulemaking webpage at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

The ISOR was circulated for public review from October 28, 2010 to December 16, 2010. The 45-day public comment period began on November 1, 2010, and ended on December 16, 2010. To meet the requirements of the California Environmental Quality Act (CEQA) under ARB's Certified Regulatory Program,

Appendix O to the ISOR included an environmental analysis of the proposed regulation (*Appendix O: Functional Equivalent Document*). The environmental analysis identified potentially significant adverse environmental impacts that may result from implementation of the proposed regulation, and identified potentially feasible mitigation measures and alternatives. The analysis concluded that there was potential for significant adverse impacts in the following areas: air quality, biological resources, cultural resources, geology and soils, hydrology and water quality, noise, transportation and traffic, and land use.

Following a public hearing held on December 16, 2010, the Board adopted Resolution 10-42, which directed staff to make a number of modifications to the proposed regulation. On July 25, 2011, the first Notice of Public Availability of Modified Text and Availability of Additional Documents (First 15-Day Change Notice) was issued. The public comment period for the First 15-Day Change Notice ended on August 11, 2011. On September 12, 2011, additional modifications to the regulatory text were proposed in a Second Notice of Public Availability of Modified Text and Additional Documents and Information (Second 15-Day Change Notice). The public comment period for the Second 15-Day Change Notice ended on September 27, 2011. The additional modifications address comments ARB staff received on the first 15-day Change Notice, and were the result of additional staff analysis and stakeholder engagement.

Staff will prepare written responses to all public comments received during the initial 45-day comment period, at the December 16, 2010 Board hearing, and during the two supplemental 15-day comment periods. Staff's written responses will be contained a Final Statement of Reasons (FSOR) which, upon its completion, will be available in electronic form on the ARB rulemaking webpage at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm. The FSOR will not include written responses to comments submitted in connection with the October 20, 2011, Board hearing.

Prior to the Board hearing, ARB will make available a subset of these written responses that pertain to Appendix O to the ISOR. The responses pertaining to Appendix O will be contained in a document entitled *Response to Comments on the Functional Equivalent Document for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms* (Response to FED Comments). For CEQA purposes, under ARB's Certified Regulatory Program, the Response to FED Comments will be considered by the Board prior to taking final action on the proposed regulation.

OCTOBER 20, 2011 BOARD HEARING:

At the hearing, ARB staff will make a presentation regarding the proposed cap-and-trade regulation, with the modifications identified in the First and Second 15-day change notices, and will recommend that the Board take final action to adopt the proposed regulation (including the four compliance protocols incorporated by reference in the proposed regulation: the Compliance Offset Protocols for Livestock Projects,

Ozone Depleting Substances Projects, Urban Forest Projects, and U.S. Forest Projects). As part of the recommended adoption of the proposed regulation, Staff will also recommend that the Board approve the Response to FED Comments and the *Adaptive Management Plan for the Cap-and-Trade Regulation* (Adaptive Management Plan).

At the hearing, the Board will decide either to adopt the proposed regulation, or decline to adopt the proposed regulation. The Board will not have the option of making changes to the regulation as part of this rulemaking action. This is because the deadline for submitting the cap-and-trade rulemaking action to the Office of Administrative Law is October 28, 2011. Because changes to the cap-and-trade regulation cannot be adopted unless they are first made available for a 15-day public comment period (see Government Code section 11346.8(c)), there is not enough time for a public comment period before the legal deadline for submitting the rulemaking package to the Office of Administrative Law. If the regulation is adopted by the Board, however, changes to the regulation can be made in the future as part of a separate regulatory action.

Copies of the text of the proposed regulation, the Response to FED Comments, and the Adaptive Management Plan will be available prior to the Board hearing on ARB's rulemaking webpage at:
http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

Copies may also be obtained at ARB's Public Information Office, 1001 I Street, First Floor, Environmental Services Center, Sacramento, California, 95814, (916) 322-2990.

SUBMITTAL OF COMMENTS

Interested members of the public may present comments orally or in writing at the meeting, and comments may be submitted by postal mail or by electronic submittal before the meeting. Written and oral comments will be considered by the Board and will be part of the administrative record for the cap-and-trade rulemaking action. However, ARB staff will not prepare written responses to these comments, and they will not be included in the Final Statement of Reasons.

To be considered by the Board, written comments, not physically submitted at the meeting, must be received **no later than 12:00 noon on October 19, 2011** 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 (Government Code section 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.

SPECIAL ACCOMMODATION REQUEST

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CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: October 7, 2011

Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms

October 10, 2011

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Response to Comments on the Functional Equivalent Document Prepared for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms

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I. INTRODUCTION

To meet the requirements of the California Environmental Quality Act (CEQA) under ARB's Certified Regulatory Program, the California Air Resources Board (ARB) staff prepared and circulated for public review a Functional Equivalent Document (FED or environmental analysis) for the California Cap on GHG Emissions and Market-Based Compliance Mechanisms Regulation (Cap-and-Trade Regulation or Regulation). The FED was included as Appendix O to the Initial Statement of Reasons (Staff Report) prepared for the Regulation, and was circulated for public review and comment from October 28, 2010 to December 16, 2010. Two Notices of Public Availability of Modified Text and Availability of Additional Documents (15-Day Changes) were subsequently issued. The two sets of 15-Day Changes modified regulatory text to provide clarity and were largely administrative. Some of the regulatory modifications would result in the Regulation being more environmentally protective (offset provision and forest protocol). The modifications do not cause new or additional compliance responses by covered entities and do not affect the environmental impact analysis in the FED. Therefore, no revision to the FED analysis or recirculation of the FED is required. The ISOR entitled *Initial Statement of Reasons: Proposed Regulation to Implement the California Cap-and-Trade Program* and other rulemaking documents are available at ARB's rulemaking webpage at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

This document presents ARB's written responses to comments on the FED that raise significant environmental issues and were received during the initial 45-day comment period, at the December 16, 2010 Board hearing, and during the comment periods for the two 15-Day Change Notices. In accordance with ARB's Certified Regulatory Program, the Board will consider the Response to FED Comments for approval prior to taking final action on the proposed Regulation.

Staff will also prepare written responses to *all* public comments received, not just FED comments, for purposes of the Administrative Procedures Act. The complete written responses to all comments will be included in the Final Statement of Reasons (FSOR) prepared for the rulemaking. Upon its completion, the FSOR will be made available in electronic form on the ARB rulemaking webpage at http://www.arb.ca.gov/regact/2010/capandtrade10/capandtrade10.htm.

Requirements for Responses to Comments

Responses to public comments are prepared in compliance with ARB's certified regulatory program, which states:

> *Public Resources Code (PRC) section 60007. Response to Environmental Assessment*
>
> *(a) If comments are received during the evaluation process which raise significant environmental issues associated with the proposed action, the staff shall summarize and respond to the comments either orally or in a supplemental written report. Prior to taking final action on any proposal for*

which significant environmental issues have been raised, the decision maker shall approve a written response to each such issue.

In CEQA, PRC section 21091 also provides direction regarding the consideration and response to public comments. While the provisions refer to environmental impact reports, proposed negative declarations, and mitigated negative declarations, rather than a FED, this section of CEQA contains useful information for preparation of a thorough and meaningful response to comments. PRC section 21091(d) states:

(1) The lead agency shall consider comments it receives ... if those comments are received within the public review period.

(2) (A) With respect to the consideration of comments received ..., the lead agency shall evaluate comments on environmental issues that are received from persons who have reviewed the draft and shall prepare a written response pursuant to subparagraph (B). The lead agency may also respond to comments that are received after the close of the public review period.

(B) The written response shall describe the disposition of each significant environmental issue that is raised by commenters. The responses shall be prepared consistent with section 15088 of Title 14 of the California Code of Regulations, as those regulations existed on June 1, 1993.

Title 14 CCR section 15088 of the State CEQA Guidelines contains useful information and guidance for preparation of a thorough and meaningful response to comments. It states, in relevant part, that specific comments and suggestions about the environmental analysis that are at variance from the lead agency's position must be addressed in detail with reasons why specific comments and suggestions were not accepted. Responses must reflect a good faith, reasoned analysis of the comments. Title 14 CCR section 15088 (a – c) states:

(a) The lead agency shall evaluate comments on environmental issues received from persons who reviewed the draft EIR and shall prepare a written response. The Lead Agency shall respond to comments received during the noticed comment period and any extensions and may respond to late comments.

(b) The lead agency shall provide a written proposed response to a public agency on comments made by that public agency at least 10 days prior to certifying an environmental impact report.

(c) The written response shall describe the disposition of significant environmental issues raised (e.g., revisions to the proposed project to mitigate anticipated impacts or objections). In particular, the major environmental issues raised when the Lead Agency's position is at variance with recommendations and objections raised in the comments must be addressed in detail giving reasons why specific comments and suggestions were not accepted. There must be good faith, reasoned analysis in

response. Conclusory statements unsupported by factual information will not suffice.

Comments Requiring Substantive Responses

Substantive responses are limited to comments that "raise significant environmental issues associated with the proposed action," as required by PRC section 60007(a). Therefore, responses specific to comments made on the Cap-and-Trade Regulation's environmental analysis are provided, consistent with the provisions of PRC section 60007. As explained above, other substantive comments are responded to in writing in the FSOR. Where a comment raises both an issue related to and issues not related to the FED, the FED-related comments are responded to in this document and the reader is referred to the non-FED responses in the FSOR.

Commenters

ARB received 19 comment letters that included comments on the FED, including comments from three public agencies. The list below identifies the commenters that submitted FED-related comments, and includes commenter information. The commenters are depicted identically to "Section III. A. List of Commenters" in the FSOR and the comment number corresponds with the comment number in the FSOR.

Commenter ID	Commenter Information
BLUESOURCE	Roger Williams Affiliation: Blue Source Written Testimony: 12/13/2010 45-Day Comment #: 660
CBD1	Brian Nowicki and Kevin Bundy Affiliation: Center for Biological Diversity Written Testimony: 12/15/2010 45-Day Comment # 746
CBD4	Nick Lapis, Californians Against Waste; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Michelle Passero, The Nature Conservancy Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1120
CBD5	Brian Nowicki and Kevin Bundy Affiliation: Center for Biological Diversity Written Testimony: 9/27/2011 Second 15-Day Comment # 2093

Commenter ID	Commenter Information
CBE1	Adrienne Bloch Affiliation: Communities for a Better Environment Written Testimony: 12/14/2010 45-Day Comment #: 762
CIPA	Norman Plotkin Affiliation: California Independent Petroleum Association Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1134
CRPE1	Sofia Parino, Center on Race, Poverty and the Environment; Tom Frantz, Association of Irritated Residents; Penny Newman, The Center for Community Action and Environmental Justice; Teresa DeAnda, El Comite para el Bienestar de Earlimart; Martha Guzman Aceves, California Rural Legal Assistance Foundation; Anna Yun Lee, Communities for a Better Environment; Jane Williams, California Communities Against Toxics; Nicole Capretz, Environmental Health Coalition Written Testimony: 12/14/2010 45-Day Comment #: 693
CRPE4	Sofia Parino, Center on Race, Poverty & the Environment; Maria Covarrubias, Comité ROSAS; Domitila Lemus, Comité Unido de Plainview; Maria Buenrostro, Comité Luchando por Frutas y Aire Limpio; Penny Newman, the Center for Community Action and Environmental Justice; Linda Mackay, TriCounty Watchdogs; Jesse Marquez, Coalition for a Safe Environment; Angela Meszros; Strela Cervas, California Environmental Justice Alliance; Tom Frantz, Association of Irritated Residents; Salvador Partida, Committee for a Better Arvin; Ruth Martinez, Comité Si Se Puede; Ana Ceballor, La Voz de Toniville; Teresa DeAnda, El Comité Para El Bienestar de Earlimart; Gary Lasky, Sierra Club Tehipite Chapter; Shabaka Heru, Society for Positive Action; Caroline Farrell Written Testimony: 8/11/2011 First 15-Day Comment #: 1110
DWR	Veronica Hicks Affiliation: California Department of Water Resources Written Testimony: 12/15/2010 45-Day Comment #: 728

Commenter ID	Commenter Information
DWR2	Veronica Hicks Affiliation: Department of Water Resources Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1107
DWR3	Veronica Hicks Affiliation: Department of Water Resources Written Testimony: 9/27/2011 Second 15-Day Changes Comment #: 2064
FRIENDSOFEARTH2	Kate Horner, Friends of the Earth US; Rolf Skar, Greenpeace; Victor Menotti, International Forum on Globalization; Bill Barclay, Rainforest Action Network Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1175
HDDP2	Bradley K. Heisey Affiliation: High Desert Power Project Written Testimony: 12/14/2010 45-Day Comment #: 617
NCPA3	Susie Berlin Affiliation: McCarthy & Berlin, P.C. for Northern California Power Agency Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1176
NRDC4	Alex Jackson Affiliation: Natural Resources Defense Council Written Testimony: 12/16/2010 45-Day Comment #: 958
SACREB	Karen Klinger Affiliation: Sacramento Real Estate Broker Written Testimony: 12/16/10 First 15-Day Changes Comment #: 983
PCAPCD2	Name: Thomas Christofk Affiliation: Placer County Air Pollution Control District Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1051

Commenter ID	Commenter Information
USFLAW	Alice Kaswan Affiliation: University of San Francisco School of Law Written Testimony: 12/10/2010 45-Day Comment #: 486
VALERO2	Matthew H. Hodges for Patrick Covert Affiliation: Valero Companies Written Testimony: 8/11/2011 First 15-Day Changes Comment #: 1062

Location of Comment Letters on the ARB Website

All comment letters and attachments received on the proposed Cap-and-Trade Regulation are posted on the ARB website at the following link: http://www.arb.ca.gov/lispub/comm/bccommlog.php?listname=capandtrade10

To manually locate the comments on the ARB website:

- Go to www.arb.ca.gov
- Select "Climate Change Program" in the left column
- Under "Assembly Bill 32 Implementation and Other Activities", Select "Cap-and-Trade Program" on the activities tab
- Select "View All Public Comments" in the right column.

On the website, the comments are ordered by date received grouped by review period, i.e. 45-Day, first 15-Day changes (15-1), or second 15-Day changes (15-2).

II. COMMENTS AND RESPONSES

This section summarizes comments on the Draft FED and presents ARB's responses to those comments. The comments identified in this CEQA document are a subset of all comments received on the proposed Cap-and-Trade Regulation. Comments that do not pertain to the adequacy of the environmental analysis are addressed in the Final Statement of Reasons (FSOR) prepared as part of the rulemaking process.

In this Response to Comments document, individual comments are presented under the correspondence within which they were received, ordered alphabetically by COMMENT ID and identified as follows:

COMMENT ID: *This is the abbreviation used to identify the comment correspondence in which the individual comments are contained.*

Name:	*Person(s) submitting the comment*
Affiliation:	*Affiliation of the commenter(s)*
Written Testimony: M/D/Y	*Type of comment and date received*
45-Day Comment #: 123	*Comment period and unique comment number. The unique ID number corresponds to numbering in the FSOR.*

Comment: *Comments received under the COMMENT ID are presented individually as shown in this example, beginning with* ***Comment*** *on the first line.*

> **Response:** *Responses are presented following each comment. Responses are indented from the left margin.*

Comment: *All of the individual comments received under the COMMENT ID are presented as demonstrated in this example. This comment would be followed by subsequent comments from this commenter.*

> **Response:** *Responses are presented following each comment. Responses are indented from the left margin.*

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BLUESOURCE

Name: Roger Williams
Affiliation: Blue Source
Written Testimony: 12/13/2010
45-Day Comment #: 660

Comment: The Forest Carbon Developers support ARB's draft market rules and the forest project protocol in general. However, we view the proposed rules as improperly restrictive in ways that make them arbitrary or unnecessarily burdensome and expensive. In these instances, the proposed Regulation does not constitute a reasonable and rational choice, and therefore should be revised consistent with the comments below in order to be legally valid and consistent with the mandate of AB 32 under the California Administrative Procedure Act (APA) and/or the California Environmental Quality Act (CEQA). (BLUESOURCE)

> **Response:** This comment summarizes the commenter's more detailed comments provided later in the letter. See responses prepared to the applicable BLUESOURCE comments.

Comment: As a matter of environmental policy and review, ARB has failed to consider that disqualifying early-mover projects will likely result in the abandonment of those projects, thus not only increasing greenhouse gas emissions but also losing the other societal benefits provided by forest conservation projects, such as habitat and watershed protection. Although ARB recognizes its duty under AB 32 to consider overall societal benefits, including reductions in other air pollutants and other benefits to the economy, environment and public health, the Agency has failed to justify why its arbitrary date restriction is defensible in light of AB 32's mandate or why an earlier start date is not an acceptable alternative.

APA requires ARB to prepare a description of reasonable alternatives to the proposed Regulation and the agency's reasons for rejecting those alternatives, and to determine in its final statement of reasons that 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 and less burdensome to affected private persons than the adopted regulation. Similarly, Health & Safety Code section 57005 requires ARB to evaluate the alternatives and consider whether there is a less costly alternative or combination of alternatives which would be equally as effective in achieving increments of environmental protection in a manner that ensures full compliance with statutory mandates within the same amount of time as the proposed regulatory requirements. APA also requires consideration of alternatives for reducing impact on small businesses, such as the Forest Carbon Developers. Although quantification protocols are exempt from APA pursuant to AB 32, HSC section 38571, the issues raised herein are related to non-quantification eligibility criteria, which are subject to APA strictures. ARB also failed to consider these alternatives in its CEQA functional equivalent document. (BLUESOURCE)

Response: The commenter suggests that disqualifying early-mover projects will likely result in the abandonment of those projects, thus not only increasing GHG emissions but also losing the other societal benefits provided by forest conservation projects, such as habitat and watershed protection.

We disagree that the proposed Regulation would result in the abandonment of early-mover projects. The Regulation includes a process for accepting offset credits from qualified existing offset projects into the ARB compliance offsets program. This not only recognizes and rewards these actions, it also helps create an initial supply of offset credits for the cap-and-trade program. We do not agree with accepting offsets from projects before 2005 because beginning in 2005, the Climate Action Reserve (CAR) and its predecessor, the California Climate Action Registry, began adopting voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions. To ensure the GHG reductions and GHG removal enhancements being used in the compliance program are real and additional, we chose to implement the January 1, 2005, date to correspond with the adoption of voluntary offset protocols as the eligible date for transition of early action offset credits to ARB offset credits.

That said, early action offset projects that began prior to January 1, 2005 are still allowed to come into the compliance program and receive early action offset credits for reductions that they achieve between January 1, 2005 and December 31, 2014. To clarify this point we added a new section, 95973(c), that allows a commencement date prior to December 31, 2006 for early action offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k). Any reductions achieved before 2005 may still be traded and sold in the voluntary market but will not be recognized by ARB or allowed to be used for compliance.

In response to the commenter's second point, for projects developed under CAR protocols, we believe that January 1, 2005, is the appropriate date to credit the early voluntary GHG reductions and GHG removal enhancements because it reflects the timeframe in which the voluntary protocols were approved by CAR. If ARB decides to accept early action offset credits achieved under other protocols not developed by CAR, ARB will evaluate whether another date is appropriate for those credits and amend the Regulation if necessary.

In response to the commenter's third point, we added new section 95990(k) to clarify how early action offset projects transition to Compliance Offset Protocols. New section 95990(k)(2) clarifies that once an early action offset project transitions to a Compliance Offset Protocol it will begin an initial crediting period. The crediting period under the early action offset program does not count under the compliance offset program, so the early action offset project may transition any time before February 28, 2015, but must list or register with an Early Action Offset Program by January 1, 2014, (section 95990(c)(3)) to get early action offset credits. This provides a seamless transition process for early action offset

projects and guarantees them a new crediting period. It is necessary for offset projects beginning February 28, 2015, to transition to Compliance Offset Protocols to ensure consistency in the program. It is also necessary that all offset projects are following the rules of the Regulation, including the rules in the Compliance Offset Protocols. We believe that this process will incentivize early action offset projects to transition to Compliance Offset Protocols, and that it will not penalize them.

Based on the preceding explanation, the Regulation would not result in the abandonment of early-mover projects, and as such would not increase GHG emissions that could occur as a result of such abandonment.

The commenter asserts that ARB failed to consider the alternatives required by the APA and HSC in its CEQA functional equivalent document. ARB examined a reasonable range of alternatives, as required under CEQA. The commenter is referred to the description of CEQA alternatives provided as a response to CRPE1. Non-CEQA aspects of this comment are addressed in the FSOR prepared in accordance with APA requirements.

Comment: ARB's requirement that forest owners commit to restricting land-use for 100 years following the issuance of the last offset credit has not been justified by ARB either as a matter of policy or science. In our experience, this arbitrary requirement has become in practice a major obstacle to implementing forest projects, since few landowners are willing to commit land to a certain use for such an extended period for uncertain economic returns. Thus, ARB's policy is deterring beneficial projects and reducing potential environmental and social benefits. Other forest protocols, such as those developed by ACR and VCS do not impose such an unjustified temporal restriction. ARB fails to adequately examine the scientific, policy and environmental bases for this extended requirement, and thus this requirement is contrary to the APA and CEQA. Rather than demanding that land use be restricted for 100 years, the landowner commitment should be commensurate with the length of the regulatory program, and any adjustment for early withdrawal from a commitment should be proportional to the remaining atmospheric benefit of sequestered carbon. We look forward to working with ARB to refine the rules in this respect. (BLUESOURCE)

Response: Ensuring permanence is essential to the environmental integrity of the entire cap-and-trade program. Because offsets allow for an equivalent quantity of GHG emissions within the capped sectors, the CO_2 stored in biological sinks resting from offset project activities must stay out of the atmosphere for a time period comparable to the emissions they are offsetting. If they do not, the net effect would be an increase in GHG emissions to the atmosphere. Scientific estimates of the atmospheric lifetime of anthropogenic CO_2 emissions are uncertain, as CO_2 is removed from the atmosphere by a number of processes that operate at different timescales. However, 100 years should be viewed as a minimum time period for maintaining permanence because a fraction of anthropogenic CO_2 is expected to remain in the

atmosphere well beyond 100 years as it is gradually removed through processes such as silicate weathering. The period of 100 years is frequently used in international climate change policy as a standard frame of reference for determining global warming potentials and setting GHG emission reduction targets, and consequently the use of 100 years to define the permanence of reductions is consistent with other programs.

This requirement was evaluated in the FED. No adverse environmental effects were identified as resulting from this requirement and none are offered by the commenter. Therefore, ARB believes the impact analysis appropriately considers this issue and no changes to the FED are warranted. Non-CEQA aspects of this comment are addressed in the FSOR prepared for the Regulation in accordance with APA requirements.

CBD1

Name: Brian Nowicki and Kevin Bundy
Affiliation: Center for Biological Diversity
Written Testimony: 12/15/2010
45-Day Comment # 746

Comment: The Functional Equivalent Document ("FED") containing ARB's analysis of the environmental impacts of the proposed Regulation also fails to disclose, analyze, and propose mitigation for significant environmental impacts, and fails to adequately discuss a range of reasonable alternatives that could avoid these impacts. (CBD1)

Response: The commenter is referred to the discussion of alternatives provided as a response to CRPE1. ARB examined a reasonable range of alternatives, as required under CEQA. At the programmatic level, the fundamental purpose of the alternatives analysis is to determine if other broad program approaches, such as direct regulation or adoption of a carbon fee, might achieve the project objectives and lessen or avoid the potential adverse environmental impacts attributed to the proposed project.

The Forest Offset Protocol is a part of the proposed Cap-and-Trade Regulation. The alternatives do not focus on a single sector (such as food processing) or a single action (such as facility relocation), because this would be too narrowly defined to achieve the AB 32 GHG reduction goal. Development of the proposed Regulation is an ongoing process which reflects changes and suggestions received through public and stakeholder participation. In response to this specific concern, the commenter is directed to the revised regulation which reflects substantial changes to the general offset sections of the Regulation and the Forest Offset Protocol, increasing the stringency of the offset requirements, which should reduce concerns about potential adverse environmental impacts. Nonetheless, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that some of the impacts associated with forestry operations are considered potentially significant and may be unavoidable. The commenter is referred to the discussion of adaptive management provided as a response to CBE1.

Comment: The proposed regulation fails to maximize environmental co-benefits to the extent feasible. Prior to adopting a Cap and Trade system under AB 32, ARB must, "to the extent feasible," maximize additional environmental benefits to California where it is appropriate to do so. Health and Safety Code section 38570(b)(3). By using the term "feasible," the Legislature signaled its intent to require ARB to demonstrate that all appropriate measures must be taken to maximize environmental benefits, unless those measures are shown to be impracticable.

AB 32 does not define the term "feasible." However, that term has a specific meaning under other statutes, including the California Environmental Quality Act—a meaning of which the Legislature was presumptively aware when it enacted AB 32. "Feasible"

means "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors." Pub. Res. Code section 21061.1. In the CEQA context, when a lead agency rejects an alternative as economically infeasible, it must support that determination with quantitative, comparative evidence that the alternative would be economically impracticable (not just more expensive). See, e.g., Save Round Valley Alliance v. County of Inyo, 157 Cal. App. 4th 1437, 1461-62 (2007) (holding that applicant's inability to achieve "the same economic objectives" under a proposed alternative does not render the alternative economically infeasible); Uphold Our Heritage v. Town of Woodside, 147 Cal. App. 4th 587, 600 (2007) (requiring evidence that comparative marginal costs would be so great that a reasonably prudent property owner would not proceed with the project); Preservation Action Council v. City of San Jose, 141 Cal. App. 4th 1336, 1356-57 (2006) (holding that evidence of economic infeasibility must consist of facts, independent analysis, and meaningful detail, not just the assertions of an interested party). Nor may a lead agency conclude that mitigation measures are legally infeasible without an adequate basis. As the Supreme Court put it, "[a]n EIR that incorrectly disclaims the power and duty to mitigate identified environmental effects based on erroneous legal assumptions is not sufficient as an informative document." City of Marina v. Bd. of Trustees, 39 Cal. 4th 341, 356 (2006).

The Legislature's use of the term "feasible" in connection with environmental co-benefits thus imposes a specific burden on ARB—a burden that the ISOR and FED fail to meet. For many months, the Center and other organizations have identified specific, appropriate measures to ARB staff (such as, for example, measures to ensure that forest offset projects improve forest management rather than perpetuate environmentally destructive practices) that could enhance, and thus help maximize, environmental co-benefits. Many of those measures are discussed again throughout this letter. At no point, however, has ARB demonstrated the infeasibility, or even the inappropriateness, of any of these measures. The Cap and Trade regulation as proposed thus fails to comply with AB 32. (CBD1)

> **Response:** The commenter states that ARB has not demonstrated that specific measures suggested by the commenter and other groups that could help maximize environmental co-benefits (such as measures to ensure that forest offset projects improve forest management) are infeasible as required by Health and Safety Code (HSC) section 38570(b)(3). The provision cited directs ARB to: "to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit...maximize additional environmental benefits." (HSC 38570(b)(3).). AB 32 does not include a specific definition of "feasible" or criteria that should be used to determine what constitutes "to the extent feasible." AB 32 leaves the specifics of how to do so, including balancing a variety of competing concerns, up to ARB. During development of the Cap-and-Trade Regulation, ARB considered all of its statutory mandates under AB 32, including the requirement to consider measures to maximize additional environmental benefits based on evidence, including economic analysis, where appropriate "to the extent feasible and in furtherance of achieving the statewide greenhouse gas

emissions limit." The appropriate analyses are included within the ISOR for the Regulation. ARB does not interpret AB 32 to require ARB to make a formal infeasibility determination regarding specific measures suggested by the commenter and other groups.

Development of the proposed Cap-and-Trade Regulation included extensive economic analysis and the involvement of an Economic and Allocation Advisory Committee. The updated economic analysis supporting the development of the Regulation was prepared by ARB and released on March 24, 2010 (ARB 2010). Economic reasons were not cited for potential infeasibility of avoiding impacts from implementing the proposed Forest Offset Protocol. On pages 311 to 314 of the FED, ARB explains that significant adverse biological impacts are not expected from implementing the Forest Offset Protocol, because sustainable, long-term harvesting practices and natural forest management would be required and project sites would be subject to some silvicultural activities with or without a Forest Offset Protocol project. Nonetheless, the FED discloses the risk that some adverse impacts cannot be entirely eliminated and unanticipated adverse biological impacts could occur. ARB cannot speculate as to the location of such impacts, but has committed to implementing an adaptive management approach as a program design feature that affords adjustment to the Regulation if any unanticipated significant biological impacts occur. These limits are well defined in authorizing legislation for ARB's responsibilities, which do not include regulation of biological or other non-air related natural resources. This conservative assessment of the situation (i.e., tending to overstate impacts) is intended to fulfill ARB's disclosure duties under CEQA.

Non-CEQA aspects of this comment, such as APA or AB 32 requirements, are addressed in the FSOR prepared for the Regulation in accordance with APA requirements.

Comment: The FED fails to comply with the California Environmental Quality Act (CEQA), Public Resources Code section 21000 et seq., and the CEQA Guidelines, title 14, California Administrative Code, section 15000 et seq. ARB's program for adopting air quality regulations is a "certified regulatory program" for CEQA purposes. (CEQA Guidelines section 15251(d)). Accordingly, the FED must include a description of the proposed Regulation, along with alternatives and mitigation measures to minimize any significant adverse effect. Pub. Res. Code section 21080.5(d)(3); Schoen v. Dept. of Forestry, 58 Cal. App. 4th 556, 566-67 (1997). Although ARB's regulatory program is exempt from certain requirements generally applicable to environmental impact reports under CEQA, see Sierra Club v. Bd. of Forestry, 7 Cal. 4th 1215, 1229-30 (1994), the core procedural and substantive provisions of CEQA still apply. In particular, ARB may not approve a regulation if there are feasible mitigation measures or alternatives available that would lessen or avoid its significant environmental effects. See Pub. Res. Code sections 21002, 21002.1(b), 21081.

As a general matter, the FED is quick to disclaim any responsibility for implementation of measures to mitigate the potentially significant economic impacts of the cap-and-trade program. The FED repeatedly states that other agencies will be responsible for implementing those measures at the project level, see, e.g., FED at 130, but fails to demonstrate in each instance that ARB lacks any legal authority to implement mitigation at the program level. If ARB can feasibly take steps to mitigate any specific effects of this action, it must do so; it may not shift this responsibility to other agencies as a general rule. Cf. City of Marina, 39 Cal. 4th at 366-67.

The FED also relies as a general matter on impermissibly deferred mitigation in the form of "adaptive management." The FED acknowledges that the cap-and-trade program may create perverse incentives and lead to potentially significant environmental impacts. Rather than proposing measures to ameliorate those impacts as CEQA requires, however, the FED states that ARB will monitor a few limited sources of information and develop "appropriate" responses if some unidentified level of impact materializes at some point in the future. See FED at 43-51, 311-14. "Formulation of mitigation measures should not be deferred until some future time." CEQA Guidelines section 15126.4(a)(1)(B). If mitigation is deferred, CEQA requires a lead agency both to develop specific performance standards and to commit to specific mitigation actions that will be taken if those standards are not met. Id.; see also, e.g., Gray v. County of Madera, 167 Cal. App. 4th 1099, 1118-19 (2008); Endangered Habitats League v. County of Orange, 131 Cal. App. 4th 777, 793-94 (2005) (agency "goes too far" when it requires only that project proponent obtain a "report" and then comply with recommendations in the report). The FED's promises of "adaptive management" fail to meet these standards. Under the FED's "adaptive management" strategy, moreover, ARB would take unspecified "appropriate" actions only if future, unanticipated environmental consequences "interfere with or undermine" the objectives of the cap-and-trade program. See FED at 46, 47, 313. Notably, the "adaptive management" strategy does not commit ARB to taking "appropriate" action in the event that significant, unanticipated environmental impacts occur. The purpose of mitigation under CEQA is to reduce or avoid significant environmental impacts, not to advance the objectives of other legislative programs. Accordingly, the "adaptive management" strategy cannot be considered mitigation under CEQA because it does not respond to the impacts that CEQA was designed to avoid.

Finally, the adaptive management strategy is not designed to gather the information that would enable ARB to detect, much less respond to, unanticipated environmental impacts. In the air quality context, for example, ARB proposes to monitor greenhouse gas emissions from covered sources. FED at 46-47. A major concern with the cap-and-trade program, however, is that emissions trading will result in increased local concentrations of conventional and toxic pollutants; information on greenhouse gas emissions alone may not reveal whether such increases are occurring. The FED also proposes to "solicit information" from local air districts concerning new and modified permits, and to evaluate this information at least once per compliance period (i.e., once every three years). FED at 47, 51. This information, however, will not contain data on pollution increases that fall below permitting thresholds. Nor will this information

capture pollution increases associated with increasing production to limits in existing permits. Nor will a triennial review disclose pollution increases in time to develop an "appropriate" response.

In sum, the FED's "adaptive management" strategy will not prevent significant environmental effects, and will not permit ARB to respond to unanticipated effects in a timely or effective manner. Absent specific performance standards, timely and rigorous monitoring of all relevant information, and particularized responses to triggering events, "adaptive management" remains little more than a smokescreen for inadequate analysis of environmental impacts. (CBD1)

Response: The commenter argues that ARB has the responsibility to require project-specific mitigation, and that the FED relies on deferred mitigation in the form of an adaptive management approach. Specifically, the commenter states that the adaptive management approach identified in the FED does not commit ARB to take appropriate action in the event significant impacts occur in the future.

The proposed cap-and-trade regulation would require GHG reductions on a statewide level, but would not stipulate specific improvements or compliance actions by individual regulated entities. As such, it is not possible to ascertain how individual entities may choose to comply. The environmental impact analysis prepared for the proposed Cap-and-Trade Regulation evaluates reasonably foreseeable compliance responses at the programmatic level, and does not speculate as to what actions may be undertaken by individual entities. The FED recognizes that most reasonably foreseeable compliance responses entail some level of onsite construction or installation activities that are traditionally subject to local regulations. ARB does not have the regulatory authority to require and/or permit facility-specific improvements. Local air pollution control districts and/or air quality management districts (air districts) have primary responsibility for adoption and implementation of stationary and area-wide source emission control measures. The FED accurately reflects that local governments, notably cities and counties, have land use and permitting authorities (CEQA lead agency authority, zoning ordinances and regulations, building codes, construction permits, etc.) that are applicable to facility-specific projects. Such projects may be undertaken as compliance responses and would be local improvements subject to project-level CEQA analysis and local permitting.

The FED identified ARB's commitment to an adaptive management approach to assess the effectiveness of the Regulation, and identify data trends that could indicate unanticipated or undesirable results, or a need for changes to ensure the Regulation is meeting its objectives. This monitoring and feedback approach is a fluid process that evolves in response to results observed over time. ARB staff is proposing that the Board adopt an adaptive management plan that lays out a framework for an adaptive management approach to monitor the potential for

adverse impacts that could result from action taken to comply with the proposed Regulation. The plan will focus on the potential for localized air quality impacts and the potential for adverse forestry impacts resulting from the Forest Protocol.

The proposed adaptive management approach has certain attributes of mitigation, in that it can result in the reduction or elimination of potential adverse impacts for the proposed Cap-and-Trade Regulation. However, adaptive management is being proposed to be incorporated as an integral design feature of implementation of the proposed program. As such, the adaptive management approach is not "deferred mitigation." Furthermore, in the context of mitigation in CEQA, the courts have upheld project approvals where the formulation of precise mitigation is infeasible because the exact nature of potential impacts is not known at the time of project approval. Mitigation strategies have been upheld when the agency commits itself to eventually devising measures in accordance with specific performance criteria articulated at the time of project approval. (See *Sacramento Old City Assn. v. City Council* (1991) 229 Cal. App. 3d 1011, 1028-29.) By analogy, staff's proposed adaptive management plan describes ARB's commitment to a specific process, including an analysis of available data, triggers for further analyses to determine whether there are localized air quality impacts or adverse forestry impacts, and if impacts are identified, the process for devising specific mitigation measures. By analogy to mitigation strategies in CEQA, the adaptive management plan lays out ARB's performance standard for identifying and addressing these potential adverse impacts identified in the FED. If the proposed Cap-and-Trade Regulation is approved, this plan would be implemented based on direction from the Board.

Comment: The Forest Offset Protocol proposed in the Cap-and-Trade Regulation is nearly identical to the Forest Project Protocol prepared by the Climate Action Reserve. For example, as previously discussed, the Forest Offset Protocol continues to allow and incentivize even-aged management practices such as clear-cutting that imperil forest health, water quality, and biodiversity; continues to provide incentives for conversion of native forests to plantations; continues to contain loopholes that incentivize increased short-term logging (and associated GHG emissions); and continues to offer credits for non-additional forest management activities in a manner that could increase overall GHG emissions. The impacts associated with these incentives and loopholes have been detailed in a series of letters from the Center to both the Climate Action Reserve and ARB over the past year. The FED largely fails to address the specific impacts identified in this series of letters. Accordingly, the arguments raised in those letters apply with equal force to the Forest Offset Protocol proposed in connection with the cap-and-trade program. These letters are therefore attached and incorporated by reference.

The FED attempts to dismiss concerns that the Forest Offset Protocol will incentivize clear-cutting and conversion of native forests on the theory that such practices will not significantly increase carbon storage. FED at 304-05. The conclusion is dubious, and contradicted by the record of protocol development; throughout the Climate Action

Reserve's protocol development process, timberland owners and other prospective forest project proponents repeatedly insisted that clearcutting and conversion of mature, uneven-aged forests were necessary to maximize carbon sequestration. This conclusion also is purportedly based on a study of "several California forest types." Id. at 304. However, the Forest Offset Protocol applies not just in California, but throughout the continental United States. Thus the FED is devoid of any analysis as to whether the Forest Offset Protocol will incentivize clearcutting and conversion of native forests outside California. Indeed, the FED acknowledges that out-of-state projects may not be subject to the level of environmental analysis that would accompany California or federal projects. Id. at 306. The FED's conclusions that the Forest Offset Protocol will not incentivize clearcutting and conversion lack support.

Despite these conclusions, the FED acknowledges that the Forest Offset Protocol may significantly affect biological resources. FED at 313-14. The FED proposes that ARB mitigate these effects by implementing "adaptive management." As previously discussed, "adaptive management," as proposed in the FED, does not constitute effective or legally permissible mitigation for these foreseeable impacts.

In any event, it is unlikely that the adaptive management program proposed in the FED would allow ARB even to detect, much less ameliorate, the adverse consequences of the Forest Offset Protocol. The FED proposes to collect information only from annual project verification reports and from "periodic" solicitation of public and stakeholder comments. FED at 313. This information, however, will not reveal whether project proponents changed management strategies, in response to the availability of offset credits, in a manner destructive of biological or forest resources. At the very least, a more credible adaptive management program would need to collect a great deal of additional information concerning historical harvest practices at the ownership and landscape scale, changed management practices following enrollment of projects under the Forest Offset Protocol, and continuous monitoring of ecological indicators (including species population trends and water quality) on project lands. The program also would have to establish specific benchmarks or performance standards for example, a certain amount of natural forest converted to plantations, or a certain amount of uneven-aged forest converted to clearcut rotations that would trigger specific ameliorative responses. Absent adequate information, specific performance thresholds, and particularized responses, the FED's "adaptive management" program cannot function as a mitigation measure for the Forest Offset Protocol. (CBD1)

> **Response:** The FED fully analyzed the potential for adverse impacts resulting from the Forest Protocol. The Forest Offset Protocol would not allow any forest management activity that is not allowed by state, federal, or local laws and regulations. The Forest Offset Protocol includes environmental safeguards to help assure the environmental integrity of forest projects. These include requirements for projects to demonstrate sustainable long-term harvesting practices, limits on the size and location of even-aged management practices, and requirements for natural forest management that require all projects to utilize

management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales.

In accordance with these requirements, the Forest Offset Protocol is not expected to increase the size of even-aged harvested areas or to result in plantation forests. Furthermore, modeling forest growth, mortality, and harvesting over time indicate that it would be unlikely for a forest project to remain eligible (i.e., demonstrate a continued net reduction in carbon sequestration), if conversion to a single-species, single-aged plantation occurred (FED, page 304).

The cap-and-trade program is made up of many elements, must serve a large number of important objectives, and relies on the actions of a large number of participants operating in a complex market system. Therefore, unanticipated effects could occur over the life of the program. The Forest Offset Protocol in particular has been identified as potentially resulting in unexpected environmental effects on forest ecosystems and biological resources (e.g., creating incentives for less environmentally conservative management practices). Based on the available data and current law and policies that regulate forest activities, ARB concludes that substantial impacts from forest project-related impacts attributable to the proposed cap-and-trade program are unlikely. However, there is at least a possibility that some unintended impacts could occur. Accordingly, the FED takes the conservative approach in its post-mitigation significance conclusion and discloses, for CEQA compliance purposes, that some of the impacts associated with compliance responses and forestry operations are considered potentially significant and may be unavoidable.

See response to CBD1 regarding staff's proposed adaptive management plan to assess the effectiveness of the Protocol and ARB's commitment to a specific process for identifying data trends that could indicate unanticipated adverse results, triggers for further analyses to determine if impacts are result of the Protocol design, and if impacts are identified, the process for devising specific mitigation measures, such as changes to the Protocol.

Comment: The FED fails to disclose, analyze, and propose mitigation for impacts related to the biomass and biofuels exemption. Adoption of a regulation is a "project" for CEQA purposes, and the courts have recognized that CEQA requires analysis of environmental impacts associated with a regulation that creates incentives for particular actions. See Cal. Unions for Reliable Energy v. Mojave Desert Air Qual. Mgmt. Dist., 178 Cal. App. 4th 1225, 1244-45 (2009). The FED here completely fails to disclose, analyze, or propose mitigation for the reasonably foreseeable and likely significant effects of exempting all biomass and biofuels emissions from compliance obligations.

This exemption creates a strong incentive to burn biomass fuels in at least two ways. First, emissions from biomass and biofuels combustion do not give rise to any

compliance obligation, and thus will not require purchase or retirement of allowances or offsets. This will encourage use of biogenic fuels wherever fuel-switching is cheaper than the purchase of allowances or offsets.

Second, the biomass and biofuels exemption leaves a number of facilities that already use these fuels outside the cap. Those facilities, however, could choose to "opt in" to the program for the purpose of obtaining allowances. See Proposed Reg. § 95813. Emissions from those facilities would be evaluated against an "efficiency benchmark" based on natural gas combustion. ISOR at II-31. According to the ISOR, "if a facility used a cleaner fuel source, like biomass, or combusts the fuel more efficiently, it would be rewarded with more allowances relative to its actual emissions." Id. (emphasis added). This not only assumes without any support that biomass combustion is "cleaner" than natural gas, but also creates a strong incentive for biomass-fueled facilities to "opt in" to the cap-and-trade program for the purpose of obtaining valuable allowances while at the same time escaping any compliance obligation. See Proposed Reg. §§ 95812(a), 95852.2. The proposed rules thus potentially create a double "freebie" for biomass combustion: an exemption from compliance obligations, coupled with a program for distributing free allowances for that same combustion that may be sold into the market and used to justify emissions at other facilities. This double "freebie" not only incentivizes biomass and biofuels use but also risks a form of allowance double-counting that could ultimately increase GHG emissions overall.

The FED fails to disclose, analyze, and propose mitigation for the foreseeable effects of these incentives. Indeed, the FED completely fails to discuss many of the foreseeable impacts of incentivizing "decarbonization" compliance pathways involving biomass and biofuels. The only oblique mention of such impacts is in the context of cement plants using old tires to fire kilns (a process by which the natural rubber portion of the tires could be "credited as biomass"). FED at 153. Other foreseeable compliance pathways involving biomass and biofuels combustion are simply not discussed. The FED similarly contains no analysis of the impacts of incentivizing these pathways on forest resources, biological resources, geology and soils, or water quality— even though creating an incentive for biomass usage will foreseeably increase biomass harvests. This is a glaring and unlawful omission.

Burning trash, tires, and wood in place of other fuels may increase local emissions of criteria and toxic pollutants. Large-scale replacement of other energy sources with biomass will also put increased pressure on forest ecosystems, with resultant impacts on biodiversity, water quality, and forest health. The potential for these impacts is well-documented; indeed, one recent study concludes that a wide-scale shift to woody biomass energy generation could eventually result in conversion of nearly all of the world's unmanaged forests and much of its pastureland to energy plantations. Significant impacts associated with increased biomass usage may already be anticipated to result from renewable energy standards and a plethora of state and federal subsidies for biomass development. In this context, an exemption from compliance obligations for biomass emissions under the cap-and-trade program at the

very least constitutes a considerable contribution to a cumulatively significant effect. The FED fails to consider this.

Finally, the FED fails to adequately address the effects of the biomass exemption on overall greenhouse gas emissions. The document concludes that switching to "less carbon- intensive" fuels will produce a "beneficial effect" in terms of greenhouse gas emissions. FED at 184. Yet the core assumption underlying this conclusion that biomass emissions are "carbon neutral" is both unstated and unsupportable. Accordingly, biomass and biofuels may not be "less carbon-intensive" than the fuels or energy sources they replace, especially over the time frame relevant to AB 32, and especially if the replaced sources come from other potentially more costly renewables like wind and solar. Absent a protocol for tracking the sources of biomass fuels, evaluating the carbon debts associated with particular fuel sources, and reaching a defensible conclusion as to the real carbon footprint of biomass, the FED cannot rationally conclude that the biomass exemption confers an environmental benefit. (CBD1)

> **Response:** The commenter states that the FED failed to analyze the impacts of and propose mitigation for the exemption of biomass and biofuels emissions from compliance obligations. ARB disagrees with the commenter. The Updated Economic Evaluation of California's Climate Change Scoping Plan, which includes a cap-and-trade program, used the ENERGY 2020 model to assess the potential changes in energy use, both type and volume, brought on by the proposed Cap-and-Trade Regulation. The model did not indicate that the use of biomass would increase in response to the proposed Cap-and-Trade Regulation, and accordingly such an increase was not identified as an impact in the FED. The explanation for why the proposed Regulation would not have an effect is that increased use of biomass is already incentivized by existing regulations such as the Renewables Portfolio Standards and the Low Carbon Fuel Standard. The Renewables Portfolio Standard (RPS) requires publicly owned utilities to obtain 33% of their energy from renewable resources, including biomass. Most utilities are challenged to achieve the renewable target despite the availability of biomass as a renewable fuel. Increased use of biomass for energy generation created by other state policies and initiatives, such as the Renewable Portfolio Standard, is discussed in the FED (see pages 351-352).

Comment: Under CEQA, the FED must consider a range of reasonable alternatives that would feasibly attain most of the objectives of the Cap-and-Trade Regulation while avoiding or substantially lessening its significant impacts, and must compare the relative merits of these alternatives. CEQA Guidelines § 15126.6(a). The FED fails to consider any alternative formulations of the Forest Offset Protocol that could meet these standards.

The Center and numerous other organizations have proposed alternative formulations to ARB throughout the past year. For example, ARB could have considered a version of the Forest Offset Protocol that eliminated clearcutting and other forms of even-aged

management. ARB also could have considered restricting the conversion of uneven-aged, native forests to fast-growing plantations, and could have considered the inclusion of additional carbon pools. Finally, ARB could have considered a version of the protocol that corrected additionality problems caused by the protocol's failure to incorporate long-term sustained yield plans into the project baseline. These alternatives, alone or in combination, would have advanced many of the core objectives of the cap-and-trade program. Had ARB considered these alternatives, it could have compared them, alone or in combination, to the proposed Forest Offset Protocol, and evaluated their feasibility.

The FED failed to do so. Instead, the FED purports to have rejected "Environmental Performance Standards" for all compliance protocols. FED at 370. According to the FED, such standards are infeasible because: (a) they are unnecessary, given the existence of strong environmental laws in California; (b) they would be difficult to apply outside of California due to differences in local law; (c) it would be impossible to create performance standards that work across a wide range of project locations and conditions; and (d) implementing standards would create an administrative burden affecting the functioning of the offset market.

The FED's rejection of Environmental Performance Standards is puzzling at best and disingenuous at worst given that similar environmental standards already have been incorporated into every protocol ARB has proposed for adoption. These standards, such as the natural forest management requirement for forest projects and the limitation on clearcut size, have been applied regardless of California or local law, regardless of differences in project locations and conditions, and regardless of administrative burden. ARB cannot rationally reject alternative formulations of these standards as "infeasible" when the factors supposedly rendering them infeasible are common to the proposed project as well.

In order to reject an alternative as infeasible, the FED must set forth adequate quantitative, comparative data to enable the public and decision-makers to reach a rational conclusion. See, e.g., Save Round Valley Alliance, 157 Cal. App. 4th at 1461-62; Uphold Our Heritage, 147 Cal. App. 4th at 600. The FED does not even identify the particular "Environmental Performance Standards" that it supposedly finds infeasible, much less present adequate data and analysis in support of its conclusions. Accordingly, the FED's approach is unlawful, and the document must be revised to include discussion of a range of reasonable alternatives to Forest Offset Protocol design—including the alternatives identified above and in prior communications with ARB—that could ameliorate environmental effects while furthering AB 32's objectives. (CBD1)

> **Response:** The commenter suggests that the FED did not include a reasonable range of alternatives and states that ARB did not evaluate any alternatives to the Forest Offset Protocol. ARB disagrees. ARB examined a reasonable range of alternatives as required by CEQA and ARB's Certified Regulatory Program (CRP). Refer to the response presented under CRPE1 regarding the reasonable

range of alternatives considered in the FED. As described on page 368-370 of the FED, ARB evaluated five (5) alternatives to the cap-and-trade program. At the programmatic level, the fundamental purpose of the alternatives analysis is to determine if other broad program approaches, such as direct regulation or adoption of a carbon fee, might achieve the project objectives and lessen or avoid the potential adverse environmental impacts attributed to the proposed project. The Forest Offset Protocol is a part of the proposed Cap-and-Trade Regulation. The alternatives do not focus on a single sector (such as food processing) or a single action (such as facility relocation), because this would be too narrowly defined to achieve the AB 32 GHG reduction goal. Development of the proposed Regulation is an ongoing process that reflects changes and suggestions received through public and stakeholder participation.

The commenter is referred to the 15-Day revisions to the Regulation that increase the stringency of the offset provisions and Forest Offset Protocol requirements. Examples of proposed revisions include:

- Offset Project Operators or Authorized Project Designees must submit to California's jurisdiction to resolve disputes regardless of the physical location of the offset project.
- Additional attestations are required when an offset project is listed.
- The Offset Project Operator or Authorized Project Designee must disclose any offset credits issued for the same project for any other purposes in any other program.
- An offset verification team must review listing information submitted by the Offset Project Operator or Authorized Project Designee.
- A verification body must submit verification reports to Offset Project Registries with the Offset Verification Statement.
- Revision to the Compliance Offset Protocol U.S. Forest Projects disallows the use of Qualified Positive Offset Verification Statements because, for forest projects, ARB must ensure all protocol requirements are met, including sustainable harvesting requirements.
- Provisions have been added to deter forest project owners from terminating their offset projects early given permanence requirements that require the sequestration of carbon for 100 years. The Offset Project Operator or Authorized Project Designee must replace any reversed tons calculated pursuant to Compliance Offset Protocol, U.S. Forest Projects to ARB within 90 calendar days. If the Offset Project Operator or Authorized Project Designee does not replace the ARB offsets within the 90 days and ARB offset credits are retired from the Forest Buffer Account, ARB will assess penalties.

With regard to consideration of Environmental Performance Standards, the commenter recommends their use for the Forest Offset Protocol and expresses concern regarding ARB's conclusion that they would be infeasible as applied to the Cap-and-Trade Regulation. The FED explains on page 370 why the use of

Environmental Performance Standards is not feasible. The reasons are both practical (i.e., inability to cover the spectrum of potential sites and circumstances for Forest Offset projects) and legal (i.e., the potential for California-defined environmental standards to be inconsistent with the laws and regulations of other jurisdictions). Further, in California, defining Environmental Performance Standards is not necessary because criteria are established by existing environmental protection laws and regulations.

It is reasonable to expect adequate protection of environmental resources that are outside of the regular purview of ARB by relying on other applicable environmental laws and regulations within California and in other jurisdictions. Protection of other types of natural resources is best pursued by the agencies with jurisdiction over those resources, such as the Department of Fish and Game for California's wildlife. To attempt to create a separate set of standards specially applied to one type of forest activity (i.e., a forest offset project) could involve conflicts and inconsistencies with established regulatory programs, unnecessarily complicating forest management and resource protection.

ARB recognizes the importance of avoiding significant effects when implementing regulatory actions. To this end, see response to CBD1 regarding adaptive management.

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CBD4

Name, Affiliation: Nick Lapis, Californians Against Waste; Paul Mason, Pacific Forest Trust; Peter Miller, Natural Resources Defense Council; Brian Nowicki, Center for Biological Diversity; Timothy O'Connor, Environmental Defense Fund; Michelle Passero, The Nature Conservancy
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1120

Comment: We understand that ARB expects the mitigation of environmental impacts resulting from the Cap and Trade Regulation to consist primarily of an adaptive management program, which in turn will largely rely on the information collected pursuant to the Mandatory Reporting Rule. As we stated in our comments to the Cap and Trade Regulation and associated FED, such an approach constitutes impermissibly deferred mitigation under CEQA. If mitigation is deferred, CEQA requires a lead agency both to develop specific performance standards and to commit to specific mitigation actions that will be taken if those standards are not met. As proposed in the proposed modifications, the Cap and Trade Regulation still lacks legally required performance standards and commitments to specific mitigation actions. Indeed, without these benchmarks and performance standards, it is impossible to determine even what information must be collected. Neither the Cap and Trade Regulation nor the Mandatory Reporting Rule identifies benchmarks that would trigger actions to mitigate environmental impacts, nor do they commit ARB to taking action in the event that significant, unanticipated environmental impacts occur.

In sum, absent specific performance standards, timely and rigorous monitoring of all relevant information, and particularized commitments to respond in specified ways to triggering events, the "adaptive management" approach described by ARB will not prevent significant environmental effects, and will not permit ARB to respond to unanticipated effects in a timely or effective manner. As a result, ARB's proposed adaptive management approach to mitigation violates CEQA. The rule, as proposed in the proposed modifications, also represents a failure to comply with Board direction. In their resolution accompanying the approval of the Cap and Trade Regulation in December 2010, the Board directed the Executive Officer to: "Determine whether there are feasible alternatives or mitigation measures that could be implemented to reduce or eliminate any potential adverse environmental impacts..." and to adopt "any modifications that are necessary to ensure that all feasible mitigation measures or feasible alternatives that would substantially reduce any significant adverse environmental impacts have been incorporated into the final action..." The additional reporting requirements in the 15-Day changes for the Mandatory Reporting Rule require the collection of basic information about the mass of forest biomass material and the harvest permit under which it was collected. However, with respect to environmental impacts to forests, this falls far short of satisfying the above directives by the Board or establishing specific performance standards. (CBD4)

> **Response:** See response to CBD1 regarding the proposed adaptive management approach and why it does not constitute "deferred mitigation."

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CBD5

Name: Brian Nowicki and Kevin Bundy
Affiliation: Center for Biological Diversity
Written Testimony: 9/27/2011
Second 15-Day Comment #: 2093

Comment: The proposed modifications eliminate section 95852.2(a)(4)(c), which had required that wood and wood waste materials to be combusted as biomass fuel "not transport or cause the transport of species known to harbor insect or disease nests outside zones of infestation..." (Page A-103.) The notice offers this explanation: "Section 95852.2(a)(4)(C) was removed in response to comments received from stakeholders who claimed that tracking and enforcement of sources of wood and wood wastes is extremely difficult for energy generators." However, there is a high probability that commercial timber land owners - who may not be able to harvest trees killed by bark beetles and disease for lumber or other durable wood products - would welcome the opportunity to sell those trees to biomass energy generators. To the extent that it makes harvest and transportation of these trees economical, the biomass fuel market is likely to become a significant driver of the harvest of trees killed by insects and disease. The elimination of this requirement openly invites the transport of infected and infested materials. This creates a substantial threat to California's forest resources and represents bad public policy. Purchasers of biomass fuels in large quantities - such as owners and operators of biomass power plants can be expected for sound business reasons to enter into contracts with fuel suppliers such as large timber corporations and the United States Forest Service. Those contracts easily could specify that the operators will not accept fuels if doing so would require the transport of infested and diseased materials. Relieving a few "stakeholders" of this purported burden cannot outweigh ARB's responsibility, as an agency required to uphold the public trust, to ensure that its actions do not threaten California's forests as a whole by exposing them to transportation of insects and disease. (CBD5)

> **Response:** The commenter indicates that the removal of Section 95852.2(a)(4)(C) would invite transport of infected and infested materials, thereby possibly resulting in a new environmental impact. ARB disagrees. The California Department of Forestry has oversight of the harvesting of wood and wood wastes, and is required to identify species known to harbor insect or disease nests and approve transportation.
>
> PRC, Ch.10, Article 5, is dedicated to Forest Insect and Plant Disease Control. State laws authorizing the control of forest pests, including Sections 4712-4718, 4799.08-4799.12, and the Federal Forest Pest Control Act (Public Law 110), allows broad administrative discretion in the use of public funds to detect and control forest pests on lands of all ownerships.

PRC Section 4715 allows the Department of Forestry and Fire Protection, in accordance with policy established by the Board of Forestry, to enter into agreements with any owner and with any agency of government, including the federal government, for the purpose of controlling or eradicating forest insects or plant diseases damaging or threatening destruction to timber or forest growth, and it may make expenditures for that purpose.

PRC Section 4716 grants the following authority to the Director of the Department of Forestry and Fire Protection.

> (a) Whenever the director determines that there exists an area that is infested or infected with insect pests or plant diseases injurious to timber or forest growth and that the infestation or infection is of such a character as to be a menace to the timber or timberlands of adjacent owners, the director, with the approval of the board [Board of Forestry], may declare the existence of a zone of infestation or infection, and describe and fix its boundaries.
>
> (b) If the director declares the existence of a zone of infestation or infection pursuant to subdivision (a), the department or its agents may go upon state and private lands within the zone of infestation or infection and shall cause the infestation or infection to be eradicated or controlled in a manner that is approved by the board.

Further, Forest Practice Rules 917.9, 937.9, 957.9, 957.10, 957.11. "Prevention Practices" contain guidelines that address the buildup of destructive insect populations or the spread of disease, hazard reduction and treatment alternatives.

Notwithstanding the protection of regulatory restrictions on the potential transport of invested plant or woody materials, the economics of biomass power plants would preclude transport of materials far from the plant or woody fuel source. Fuel costs are critical to the economic viability of biomass power plants and transportation costs can be the largest component of the cost of fuel. As a result, the "fuel shed" of a biomass power plant must be a limited distance from the plant. Prior environmental investigations have found that within 50 miles, the transport of biomass fuel can still be viable and beyond that distance, the transport begins to be economically infeasible. Therefore, if any material were to carry an infestation, the environmental effect would be minimized by the economic limitations of the cost of fuel transport. Once at the plant, the fuel would be combusted and the risk of spreading an infestation would be eliminated. Recognizing the regulatory protections and the limited distance of fuel transport, any potential for environmental effects from infested plant or woody materials would be less than significant (Amador County 2010a, pages 3-14 to 3-15 and 5-25 to 5-26; Amador County 2010b, pages 2.5-15 and 2.5-24).

CBE1

Name: Adrienne Bloch
Affiliation: Communities for a Better Environment
Written Testimony: 12/14/2010
45-Day Comment #: 762

Comment: Large California NOx, CO, and other co-pollutant reductions can be achieved if an alternative is adopted requiring direct control measures using methods known by CARB (e.g. for boilers and heaters). These co-pollutants otherwise cause large cumulative impacts in impacted communities. Similarly, CARB should evaluate other co-pollutants including PM2.5 and toxics which feasible direct controls would achieve. AB 32 requires addressing the co-pollutants issues, but the proposed cap-and-trade regulation and Scoping Plan do not. (CBE1)

Response: In developing the Scoping Plan in 2008, the Staff Report for the Cap-and-Trade Regulation, and again in the *Supplement to the AB 32 Scoping Plan Functional Equivalent Document* (Supplement), which was presented at the August 2011 Board meeting, we evaluated the air quality impacts of a direct regulation compared to a cap-and-trade program. The proposed Cap-and-Trade Regulation is designed to reduce GHG emissions and is not directly applicable to other pollutants. However, criteria pollutants and toxic air contaminants are generally expected to decline as a result of GHG reduction measures. Consequently, the proposed Cap-and-Trade Regulation would not contribute to a cumulative increase in co-pollutants. FED page 343.

The proposed Cap-and-Trade Regulation has the distinct advantage of imposing an enforceable cap on emissions - making it the most likely method to successfully meet the AB 32 goal of capping emissions at 1990 levels by 2020. As described on page IV-3 of the proposed Cap-and-Trade Regulation Staff Report, direct regulations for emission sources do not provide the same assurance of reductions as those offered by a cap-and-trade program.

The proposed Cap-and-Trade Regulation and the source specific alternative share challenges. If a cap-and-trade program is not adopted, ARB would instead have to adopt numerous source-specific regulations on many different types of sources. Before ARB adopts a regulation on a source category, staff must spend considerable time investigating the category to determine what level of emissions control is cost effective and technologically feasible. Some sectors may not be regulated at all because, after investigation, staff determines that emission standards are not cost-effective or technologically feasible, or that the potential emission reductions are so small that regulation is not justified.

In addition, it takes considerable time to develop each individual regulation. This means that some sources will be regulated first; others will be regulated later - perhaps much later if the category presents difficult technical issues.

Even if regulations are ultimately determined to be feasible and are adopted, the delay in adoption, and the potentially long lead times necessary for some sources where feasibility is an issue would mean that emission reductions at certain sources will likely occur much later than at other sources. It is, therefore, very difficult to predict at this time (i.e., before staff has done the necessary technical work) both where emission reductions will occur and when they will occur. Some sources or source categories near environmental justice communities may remain unregulated, or may achieve emission reductions much later than if the source had instead been regulated under the cap-and-trade program.

Another reason why uncertainty is a characteristic of regulatory systems relying on source-specific regulations is that each source-specific regulation can be designed in different ways. Different levels of emission controls can be specified, and source-specific regulations often have exemptions for certain types of sources that cannot comply with a specified standard. Many regulations also have compliance flexibility features that allow such options as the use of averaging or even the use of offsets to meet some compliance obligations. Because of these exemptions or compliance flexibility features, there is no guarantee that uniform reductions at each individual source will occur. Different impacts to neighboring communities could, therefore, result from the Regulation, as compared to a regulation without such flexibility.

Exemptions or compliance flexibility that may be included in any source-specific regulation may be superficially appealing but present serious downsides. One reason that exemptions may be included in a source-specific regulation is that not all individual sources can achieve the same level of emission reductions due to various factors such as the source's age or use of particular types of equipment. If a standard is set that all facilities can meet (e.g., in order to satisfy the requirements of technological feasibility and cost-effectiveness set forth in AB 32) the emission standards may have to be set much less stringently in order to meet these requirements. If carefully targeted exemptions or less stringent standards are instead allowed for certain types of facilities, the standards on the remaining sources may be able to be set much more stringently. Such a regulatory structure may be necessary in order to achieve the maximum feasible emission reductions (another requirement of AB 32) from the source category as a whole. The same rationale may also justify the inclusion of flexibility options in a source-specific regulation.

Comment: A highly preferable alternative proposal would have been a thorough evaluation of Reasonably Available Control Measures necessary to meet CARB's requirements under AB 32 for maximum reductions, to reduce smog in non-attainment zones, and toxics in overburdened heavily industrial areas. The following sections identify specific sources that should have been considered. For example, additional reductions could be achieved from:

(1) Requiring In-State reductions from industrial boilers and heaters, which CARB has already identified.

(2) Removing industrial exemptions for methane from smog regulations.

(3) Requiring implementation of specific refinery by refinery measures identified in the industrial energy efficiency audits.

(4) Limiting emissions and conversion to processing Heavier Crude at oil refineries (which is not cancelled out by adding polluting ethanol to gasoline).

(5) Requiring oil refineries to switch fossil fuel electricity use to clean alternative energy sources (since oil refineries use significant electricity). (CBE1)

Response: See the response to CRPE1 regarding the reasonable range of alternatives considered in the FED. See response to comment CBE1 regarding consideration of source-specific reduction alternative, above. The commenter offers a range of source-specific GHG reduction measures that could be implemented by ARB. These measures have been considered in the context of evaluating the Additional Source-Specific Command-and-Control Regulations Alternative (see page 387-390 of the FED).

ARB examined a reasonable range of alternatives as required under CEQA. The array of source-specific measures recommended in the comment presents a scenario of additional regulatory actions. ARB staff believes that most of the measures suggested by the commenter are not feasible and the remaining measures, while they have some reduction potential, may be substantially inflated relative to what a regulatory approach might actually cost-effectively achieve.

ARB has adopted an energy efficiency and co-benefits audit regulation. The audit results from this regulation are due at the end of 2011. ARB staff has committed to evaluate opportunities to achieve facility-specific cost-effective emission reduction opportunities that will result in GHG and co-pollutant benefits and require these reductions under a regulatory program. Staff does not believe that mandated improvements of this type are administratively feasible under a regulation at this time due to the lack of data on specific reductions that can be achieved.

Comment: Boiler and Heater NOx and CO Co-pollutant emissions are large and if directly controlled would yield large local health benefits. AB 32 requires ARB to design the program to prevent any increase in emissions of toxic air contaminants or criteria pollutants. It also requires it to consider the overall societal benefits of reducing other

air pollutants and benefits to the environment and public health. Yet the draft regulation demonstrates that reductions could have been achieved to substantially reduce co-pollutant emissions but was rejected.

CARB provided two spreadsheets calculating available measures for reducing CO_2 emissions from industrial boilers and heaters, which are major pollution sources. Measures include replacing old boilers of low or medium efficiency, optimizing combustion, improving insulation maintenance, etc. (listed below and in the attached spreadsheets). CARB identified how much energy would be saved for each of these measures in MMBTU (million British Thermal Units). CARB provided these reduction opportunity calculations not because these are being directly mandated, but to show possible ways that industrial sources could reduce, but are nevertheless allowed to buy their way out of under Cap and Trade. There was no showing that these reductions would not have been cost-effective. Regardless, the CARB list underscores the availability of measures for direct control. If these controls were implemented locally instead of traded, they would not only result in the CO_2 emissions reductions identified by CARB, but would also result in very substantial co-pollutant reductions. CARB should have considered such an alternative project to address co-pollutant impacts.

It is a simple matter to calculate the co-pollutants associated with the energy savings identified in the boiler and heater spreadsheets. For example, standard AP42 emission factors for NOx and CO are available, based on natural gas combustion. This will generally underestimate emissions because more polluting fuels are often used by these boilers and heaters, but applying the natural gas factors provides a conservative estimation, and still comes out to large emissions. The result, in tons per day, is provided below. The detailed tables are attached as an appendix. The full spreadsheets are separately attached. (CBE1)

Response: See response to CRPE1 regarding the reasonable range of alternatives considered in the FED. See response to CBE1 regarding consideration of source-specific reduction alternative.

The commenter suggests that a greater reduction of co-pollutant emissions could be achieved through the direct regulatory control of boiler and heater emissions. ARB examined a reasonable range of alternatives as required under CEQA, including the adoption of direct regulatory controls. While direct regulation offers some reduction potential, the estimated reductions presented by the commenter may be substantially inflated relative to what a rule approach might achieve. The commenter draws on material prepared by ARB staff for the proposed cap-and-trade rulemaking (Appendix F) and contends that the conceptual emission reductions that might be obtained with these measures could be required as a direct regulation. Staff is currently evaluating how facility-specific cost-effective emission reduction opportunities identified by energy efficiency and co-benefits audits due by the end of 2011 could be required under a regulatory program. The commenter is assuming the results of a broad analysis or audits are applicable over a diverse set of sources requiring widespread efficiency

improvements. Staff does not believe that mandated improvements of this type are administratively feasible under a regulation at this time. The commenter also rightfully notes the uncertainty in estimates of emission reductions possible from these types of measures due to potential overlapping of estimated reduction opportunities (such as replacing or improving boilers).

Further, although boiler and heater source-specific reduction measures could achieve substantial GHG reductions, for the reasons described in response CBE1 above, both a source-specific regulatory program and a cap-and-trade program can have a similar result in the real world, but it depends on the many details of how the regulations are designed. The FED indicates that at this time ARB cannot predict in which sectors and what geographic locations the emission reductions would occur under the source-specific alternative. However, it does indicate that emission limits applied to specific regulated entities and facilities could provide more certainty regarding the location of GHG emission reductions, which could be an environmental advantage of this alternative. In comparing the Additional Source-Specific Command-and-Control Regulations Alternative with the Cap-and Trade program, ARB determined that the source-specific alternative (see page 395 of the FED) would result in the low likelihood or no likelihood of achieving the project objectives for five objectives (i.e., equitable distribution, cost-effectiveness, minimize leakage, establish a declining cap, and linkage with partners), whereas the proposed Cap-and-Trade Regulation would have a high likelihood for achieving all objectives. For these reasons, and for other supporting economic and feasibility reasons included in the Initial Statement of Reasons, ARB has rejected this alternative as not being environmentally superior to the proposed action.

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CBE4

Name: Greg Karras
Affiliation: Communities for a Better Environment
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1166

Comment: Some of the amendments to the proposed Regulation would cause more severe and significant environmental effects than those disclosed by the draft FED, and warrant revision of the FED. ARB failed to revise and recirculate the environmental document to disclose the impacts of the amendments. Given the likely significant environmental impacts from the substantial changes to the proposed Regulation, ARB should revise and recirculate the FED before adopting any amendments to the proposed Cap and Trade Regulation.

CEQA requires that the agency prepare a response to comments before adopting a final EIR or FED. This final action is due in October 2011. Yet, at the same time, the Board has directed the Executive Officer to report back to the Board in July 2011 on the "finalization of the allowance allocation system", "implementation of a market tracking system", "implementation of an auction system", and "implementation of an offset tracking system." At the same time comments are being taken, and before the final FED is prepared, ARB will be actively preparing markets for Cap and Trade. As such, the Board has adopted a Cap and Trade Regulation before completing CEQA.

The process is further aggravated because the Board in its December resolution also directed the Executive Officer to "modify" several aspects of the Regulation, and never mentioned considering the environmental consequences of the changes. The Board has not considered CEQA or environmental consequences at all in deciding whether or not to approve this project. The Executive Officer alone will review the FED comments, which are based on the pre-amendment regulations. The Executive Officer should at least have the benefit of comments on the completed draft EIR, one that reflects the true project and its impacts.

During the comment period for the Scoping Plan alternatives, ARB also released amendments to the Cap and Trade Regulation for public comment. ARB's decision to create an overlapping comment process also undermines public participation and ARB's ability to genuinely consider the project's significant impacts. It is not possible to fully comment on both documents at once. ARB's insistence on thrusting this Regulation forward without ensuring that it will avoid significant impacts casts serious doubt on the process as a whole and CARB's willingness to hear from all but a select few "stakeholders" whose opinions are solicited. (CBE4)

> **Response:** The commenter expresses an opinion that the Board has adopted the Cap-and-Trade Regulation before completing CEQA, that the Board has not considered CEQA or the environmental consequences of the proposed 15-Day changes, and that ARB's decision to create an overlapping comment process undermines public participation. The commenter suggests that the FED should

be revised and recirculated before adopting any amendments to the proposed Cap-and-Trade Regulation.

The commenter suggests that ARB has not considered the environmental effects of the proposed changes directed by the Board in its December 2010 resolution. This is not correct. Following a public hearing held on December 16, 2010, the Board adopted Resolution 10-42, which directed staff to make a number of modifications to the proposed Regulation. On July 25, 2011, the first Notice of Public Availability of Modified Text and Availability of Additional Documents (First 15-Day Change Notice) was issued. The public comment period for the First 15-Day Change Notice ended on August 11, 2011. On September 12, 2011, additional modifications to the regulatory text were proposed in a Second Notice of Public Availability of Modified Text and Additional Documents and Information (Second 15-Day Change Notice).

The commenter offers no evidence to support the contention that the analysis in the FED warrants revision and recirculation. ARB staff reviewed the 15-Day changes and determined that the changes would not result in new impacts or change the level of significance of already identified impacts, and therefore does not require revision or recirculation of the FED. (See also response to CPRE4.)

ARB concurrently complies with APA and CEQA requirements through its CRP. ARB typically has multiple regulatory proposals underway on parallel time frames and complies with the environmental review requirements for all of them. ARB has complied with the requirements of its CRP for the preparation and circulation of the FED and preparation of these written responses to comments.

With regard to adoption of the proposed Cap-and-Trade Regulation, ARB disagrees with the commenter. The Board has not taken final action to adopt the proposed Regulation prior to completion of the environmental process. The Board is scheduled to consider the responses to comments on the FED at the October 20, 2011 hearing prior to taking final action on the Regulation.

Comment: ARB's revisions to tables 8-1 and 9-1 of sections 95870 and 95891 would cause more severe and significant environmental effects than those disclosed by the draft FED. These changes revise the timing and amount of refinery emissions which ARB proposes to "allocate" for free (proposes not to control) in ARB's proposed equation given in section 95891. As ARB's own AB 32 program documentation acknowledges, oil refineries are the largest industrial emitter in its program. (CBE4)

Response: As noted by the commenter, the 15-Day changes provide additional detail on industry benchmarking and allowance allocations. The modifications are consistent with anticipated and ongoing refinement of the proposed Regulation and do not substantially alter the magnitude of potential environmental impacts or the suggested level of significance presented in the Draft FED. Benchmarking is a process to estimate representative emission

factors by sector, and provide a baseline for allowance allocation. The referenced 15-Day changes simply incorporate benchmark values that were not available when the Draft FED was prepared. The provision of free allowances is proposed to minimize potential leakage in exposed sectors, and was addressed in the Draft FED on pages 9 and 40:

> "Staff proposes to create a gradual transition into the program through the design of the allocation system. ARB will rely primarily on free allocation at the start of the program to minimize near-term costs to California consumers and businesses and to minimize emissions leakage. The allocation design will reward those who have invested in energy efficiency and GHG emission reductions and will encourage continued investment in clean and efficient technologies in the future."

A common misconception is that the provision of free allowances discourages a covered entity from implementing measures to reduce emissions. In fact, the provision of free allocations does not result in fewer improvements being implemented by covered facilities. Although an entity could simply return allowances at the close of a compliance period, if the value of the allowances exceeds the cost of improvements, free allowances provide opportunities for entities to implement compliance actions at reduced cost.

Comment: ARB added section 95852(a)(2) to the proposed cap and trade regulation. This new section appears to exempt oil refineries from including the major greenhouse gas emissions from combustion of fuels, including natural gas liquids. Natural gas can be stored as liquid natural gas, which is later burned as natural gas. This exemption would cause significant air pollution impacts and exacerbate pollution hotspots by taking one of the largest sources of combustion emissions at refineries completely out of any compliance requirement.

Response: The proposed change does not exempt these fuels from regulatory compliance. In 2015, the compliance requirement for these fuels simply changes from the facility combusting the fuel to the facility/operator providing the fuel. Refineries both provide the fuel and combust the fuel, and as such would continue to be responsible for compliance after 2015.

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CIPA

Name: Norman Plotkin
Affiliation: California Independent Petroleum Association
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1134

Comment: In currently pending litigation, a California State trial court found that the analysis of the alternatives identified in the FED was not sufficient for informed decision-making and public review under CEQA. Under the abuse of discretion review taking place, a Supplement was prepared to provide an expanded analysis of the five project alternatives discussed in Section V of the 2008 Scoping Plan FED. Based on Alternative 5 of the Supplement, CARB has met all of the objectives and the emissions targets of AB 32. One need only eliminate Cap and Trade from that mix because the emissions reduction yield from Cap and Trade was always a "plug" number. It was a number to plug in to get to the evolving target, a catch all buffer in case actual reductions didn't materialize as projected. Cap and Trade's inclusion was a sop to business and lip service to those who believe that credit trading was the foundation for a "green economy." More importantly, a Combined Strategies alternative that does not include Cap and Trade also does not constitute a No Project designation, which is a political non-starter. (CIPA)

> **Response:** The commenter urges ARB to consider Alternative 5 from the Scoping Plan FED Supplement (which was a combination of strategies including a cap-and-trade program), but eliminate the Cap-and-Trade Regulation to reduce emissions and meet AB 32 goals. The GHG emissions reductions achieved by Alternative 5 from the Scoping Plan FED Supplement would not meet the AB 32 goal without the use of a cap-and-trade mechanism; therefore, the commenter's suggested approach would not meet the basic objective of AB 32.

Comment: The largest single impediment to the rational policy decision to jettison Cap and Trade and instead rely on the established mix of combined strategies and measures is CARB's desire to construct the mix of measures in such a fashion that the target reductions are skewed higher than necessary to meet AB 32 goals because of a desire to put California on a path to meet the long-term 2050 goal of reducing California's GHG emissions to 80 percent below 1990 levels because CARB believes this trajectory is consistent with the reductions that are needed globally to help stabilize the climate. CIPA argues that this scale is unachievable at the state level and that this policy horizon is too long for rational development of midterm solutions and is in practical effect the enemy of the good. (CIPA)

> **Response:** The commenter urges ARB to consider eliminating the Cap-and-Trade Regulation and instead consider a mix of measures to reduce emissions and meet AB 32 goals and expresses the opinion that some of the reduction levels are overstated, because of ARB's perceived desire to attain 2050 goals, rather than just 2020 goals. No specific comments on the adequacy

of the environmental analysis were raised; therefore, no further response is required.

If approved, the Cap-and-Trade Regulation would be a single regulation in a suite of GHG reduction measures implemented by ARB to reduce GHG emissions. The list of Ongoing, Approved and Foreseeable Measures is available on the ARB website at:

http://www.arb.ca.gov/cc/inventory/data/tables/reductions_from_scoping_plan_measures_2010-10-28.pdf

These measures alone do not achieve the reductions necessary to reach the AB 32 target in 2020. If the Cap-and-Trade Regulation is approved, it would achieve the additional reductions necessary to reach the target. Further, ARB is continuing to evaluate additional regulatory measures that could be implemented to reduce emissions from specific sources. Most additional measures have not reached a level of development that they can be counted towards achieving the 2020 target with a reasonable level of confidence.

Comment: In CIPA comments on the Supplement to the AB 32 Scoping Plan Functional Equivalent Document, dated July 28, 2011, we noted that the FED Supplement fails to provide an accurate baseline because the GHG reductions attributable to other programs are underestimated or omitted and the effects of the economic recession on statewide GHG emissions have been underestimated. Specifically, we argued that the FED Supplement does not include the GHG reductions associated with two measures that CARB has already adopted or is adopting, namely the Commercial Recycling Measure and the Energy Efficiency And Co-Benefits Assessment. Moreover, we pointed out that the FED Supplement does not include any of the GHG reduction programs that CARB has proposed but not yet adopted. CARB has estimated that the GHG reductions attributable to those measures total 68 MMT exceeding the 22 MMT shortfall. Yet, CARB provides no analysis in the FED Supplement as to the foreseeability of these measures or the likely effect those measures will have on achieving the AB 32 target.

Insofar as the FED Supplement ignores GHG reduction programs implemented or under development by the federal government and other state agencies such as the California Public Utilities Commission, we noted that the baseline has been skewed. Even though CARB states in the FED Supplement that it has updated the environmental baseline to account for events subsequent to the original FED prepared for the Proposed Project, CARB has not included these programs in its updated baseline. As a result, CARB's updated baseline is inflated and overstates any shortfall in achieving the AB 32 target. Indeed, proper accounting for these omitted programs could exceed the 22 MMT shortfall estimated in the Supplemental FED. Although the FED Supplement states that it has updated the environmental baseline by accounting for the effects of the recent economic recession on statewide GHG emissions, there is no explanation, let alone any quantitative analysis, as to how CARB accounted for those recessionary effects. Indeed, the only information provided in the FED Supplement on this issue is a conclusory statement that CARB relied on the energy demand forecast provided in the

2009 "IEPR" prepared by the California Energy Commission (CEC). Yet, in findings issued in March 2011 – before the publication of the FED Supplement – the CEC acknowledged that its 2009 forecast substantially under predicted the depth and duration of the recession. Accordingly, CARB's baseline of GHG emissions is significantly overstated. CIPA asserts, again, that CARB has met all of the AB 32 objectives and the emissions targets through Alternative 5 of the Supplement- Variation of the Combined Strategies or Measures. One need only eliminate Cap and Trade from that mix to arrive at a Combined Strategies Alternative that satisfies AB 32. (CIPA)

Response: The commenter urges ARB again to consider Alternative 5 of the Supplement to the Scoping Plan FED with elimination of the Cap-and-Trade Regulation. The GHG emissions reductions achieved by Alternative 5 from the Scoping Plan FED Supplement would not meet the AB 32 goal without the Cap-and-Trade Regulation; therefore, the commenter's suggested approach would not meet the basic objective of AB 32 (recognizing an updated baseline emissions projection). The commenter did not submit specific comments on the environmental analysis conducted for the Cap-and-Trade Regulation in the FED, therefore, no further response is required.

Comment: Do not be afraid to accept that CARB has met all of the AB 32 objectives and the emissions targets through Alternative 5 of the Supplement- Variation of the Combined Strategies or Measures. One need only eliminate cap and trade from that mix to arrive at a Combined Strategies Alternative that satisfies AB 32 and avoids the pitfalls that await an ill-defined market plan and does not suffer the credibility gap of a take no action alternative. We urge you to embrace adaptation as a policy response, fully count the Combined Measures and Strategies taken to date and jettison the dangerous California only Cap and Trade rule. (CIPA)

Response: Refer to response to preceding CIPA comment.

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CRPE1

Name, Affiliation: Sofia Parino, Center on Race, Poverty and the Environment; Tom Frantz, Association of Irritated Residents; Penny Newman, The Center for Community Action and Environmental Justice; Teresa DeAnda, El Comite para el Bienestar de Earlimart; Martha Guzman Aceves, California Rural Legal Assistance Foundation; Anna Yun Lee, Communities for a Better Environment; Jane Williams, California Communities Against Toxics; Nicole Capretz, Environmental Health Coalition
Written Testimony: 12/14/2010
45-Day Comment #: 693

Comment: The Board should not adopt the proposed cap and trade rule. ARB has not conducted a proper foundational analysis to justify this choice of a market mechanism, and ARB has not analyzed a reasonable range of alternatives in accordance with the California Environmental Quality Act ("CEQA"). (CRPE1)

Response: The commenter asserts that ARB has not analyzed a reasonable range of alternatives in accordance with CEQA, but provides no specificity. It is not possible to respond to this general comment, other than to reiterate that the FED complies with all applicable CEQA requirements, including analysis of alternatives.

ARB held a Scoping Meeting for the cap-and-trade FED on August 23, 2010 to solicit public input on environmental impacts and the range of project alternatives to be evaluated. The FED considered five alternatives to the project. See Chapter 6.0, "Alternatives Analysis," of the FED, including a range of market and non-market approaches to GHG reduction. Alternatives consisted of five different cap-and-trade program designs, carbon fee, direct regulation approach, and the no-project alternative. This represents the spectrum of GHG reduction strategies used by states, provinces, and nations. In accordance with the substantive requirements of CEQA, the alternatives analyzed in the FED represent a "reasonable range" that could potentially feasibly attain most of the basic project objectives while having the potential to reduce or eliminate significant environmental effects. Generally, a range of alternatives analyzed in an environmental document is governed by the "rule of reason," requiring evaluation of those alternatives "necessary to permit a reasoned choice" (See Title 14 CCR section 15126[f]). The initial screening of potential alternatives had to at least potentially meet the objectives, and alternatives were included only after consideration of their potential feasibility based on technical, legal, and regulatory grounds. The five alternatives covered a range of policy level alternatives sufficient to permit a reasoned choice.

Comment: ARB'S analysis of alternatives to the proposed Regulation violates the California Environmental Quality Act. AB 32 requires "the state board to adopt greenhouse gas emission limits and emission reduction measures by regulation," which triggers the CEQA requirement for an Environmental Impact Report (EIR). As a

certified regulatory program, ARB discussed possible impacts in the form of a Functional Equivalent Document (FED) in lieu of an Environmental Impact Report, pursuant to Public Resources Code section 21080.5.

ARB failed to adequately analyze project alternatives in the Functional Equivalent Document. Under CEQA, ARB must examine a reasonable range of alternatives to the proposed project that feasibly meet most of the project's basic objectives while avoiding or substantially reducing the significant effects of the project. The selection of alternatives should foster informed decision making and public participation. CEQA also makes clear that the purpose of the alternatives analysis is to focus on alternatives that are capable of "avoiding or significantly lessening any significant effects of the project, even if those alternatives would impede to some degree the attainment of the project objectives, or would be more costly." In evaluating alternatives, ARB must include "sufficient information about each alternative to allow meaningful evaluation, analysis and comparison with the proposed project."

For purposes of developing and evaluating the proposed project and alternatives, ARB derived the following objectives from AB 32:

- Achieve technologically feasible and cost-effective aggregate reductions;
- Distribute allowances equitably;
- Avoid disproportionate impacts;
- Credit early action;
- Complement existing air standards;
- Be cost-effective;
- Consider a wide range of public benefits;
- Minimize administrative burden;
- Minimize leakage;
- Weigh relative emissions;
- Achieve real emission reductions;
- Achieve reductions over existing regulation;
- Complement direct measures;
- Consider emissions impacts;
- Prevent increases in other emissions;
- Maximize co-benefits;
- Avoid duplication;
- Establish declining cap;
- Reduce fossil fuel use;
- Link with partners;
- Design enforceable, amendable program; and
- Ensure emissions reductions.

Having articulated these objectives (notably, without regard to their accuracy, and to the statutory requirements in AB 32), ARB then presented a cursory, circular and

results-oriented description of five alternatives to the proposed plan. The five alternatives ARB identified were:

(1) No project. This Alternative comprises the bulk of the alternatives analysis. The section generally describes sector by sector the business as usual impacts compared to the proposed Cap-and-Trade Regulation;

(2) Implement only additional source-specific command-and-control regulations. This alternative purports to consider implementation of source-specific emission limits by regulation. However, in its Executive Summary, ARB demonstrates its preference for cap and trade above all other forms of controls with an unsubstantiated conclusion that direct regulations cannot provide the same assurances for reductions that a cap and trade program because of an uncertainty in emissions reductions caused by the diverse nature of many industrial processes and a lack of data. This conclusion is not only nonsensical to justify the inclusion of these same diverse and data-poor industrial processes in a cap and trade program (under which all reductions must be real, permanent, quantifiable, verifiable, and enforceable) but is unsubstantiated, based only on the excuse that ARB does not have the data to properly regulate these industries. In its analysis, ARB acknowledges that command-and-control regulations "can take several forms."

However, instead of performing a meaningful analysis of any of the forms possible, ARB "assumed that only regulated emission limits would be implemented" on sources (as opposed to technology). As such, ARB failed to identify and analyze the specific command-and-control regulations which would be appropriate here. Instead ARB summarily states that the specifics necessary to conduct such analyses "would depend on the information that is learned in the future during the regulatory development process." And yet, prior to initiating any "regulatory development process," ARB identifies five objectives with which source-specific emission limits would not be likely to achieve in Table 6-1 on "Comparative Likelihood That Alternatives Achieve Project Objectives."

Table 6-1 ranks on a scale of high, medium, and low the likelihood that each alterative considered would be likely to achieve each of the 22 objectives ARB identified. Here, each of the "no or low likelihood to achieve objective" ratings received by the source-specific command-and-control regulation alternative pertained to objectives that were either not applicable to source-specific command-and-control regulations or not analyzed. First, stated objective two is to distribute allowances equitably. Under a source-specific emissions limit program there are no allowances to distribute and thus the objective is inapplicable here. However, the underlying intent of the specified objective appears is to ensure equitable treatment of entities. In this case that purpose is served in that there is an equitable distribution of zero allowances. Stated objective five is to complement existing air standards. While Table 6-1 rates source-specific emissions limits as low here, nowhere else in the FED is the issue addressed. In fact, the brief program description on page 388 discusses how this alternative would "likely focus primarily

on the industrial sector because the transportation, electricity and natural gas sectors are already extensively addressed." Given this cursory analysis, it appears that source-specific regulations would in fact be designed to complement existing air standards.

Stated objective nine is to "minimize leakage." However, in the objectives section ARB specifically notes that "command-and-control regulations can be designed to minimize or avoid leakage." No further explanation as to how leakage is caused, or could be minimize under this alternative, other than to say that administrative burdens may increase, is provided. Stated objective 18 is to establish a declining cap. This objective is either inapplicable, as source-specific emission limits envision no cap to begin with, or it is fulfilled by analogy. The intent of the objective is to "cover 85 percent of the state's GHG emissions in furtherance of California's mandate to reduce GHG emissions to 1990 levels by 2020." Since there is no "cap" in source-specific regulations, the objective of a "declining cap" is not applicable. However, the intent of the objective is to continually lower emission levels and this intent could be fulfilled through a source specific regulatory scheme. In fact, the U.S. EPA regularly writes mobile source emission regulations (source- specific command-and-control regulations) that increase in stringency over time.

Lastly, stated objective 20 is to link with other Western Climate Initiative (WCI) partners to create a regional market system. While Table 6-1 concludes there is no or a low likelihood of achieving this objective, there is no elucidating discussion as to why it is not possible. Generally, command-and-control regulations do not envision a market system; however, no aspect of such a program precludes regulatory schemes from linking together partners in some way. In failing to fully envision, consider, and describe how source-specific emission limits could operate in California, ARB has not included sufficient information on source-specific emission limits "to allow meaningful evaluation, analysis and comparison with the proposed project." ARB preemptively rejects this alternative as "challenging," but acknowledges that "the certainty about avoiding localized increases in emissions could be an environmental advantage of this alternative." This is a key advantage for environmental justice communities, and does not allow ARB to so quickly dismiss it in favor of a cap and trade program;

(3) Carbon fee. ARB describes implementation of a carbon fee as similar to cap and trade in that both programs place a price on GHG emissions, which thereby provides an incentive for businesses and individuals to reduce their emissions. Similarities between the two programs include "reporting, monitoring, verification of covered entities' GHG emissions." ARB states that the main difference between the programs is that implementing a carbon fee "provides price certainty for the covered entities" but lacks emission certainty. ARB's analysis of a carbon fee is fundamentally flawed in again failing to envision and analyze how the program would actually work. Thus, it fails to meet CEQA's requirement for "sufficient information about each alternative to allow meaningful evaluation, analysis and comparison with the proposed project." Instead of developing a real alternative, ARB focuses on

elements of the proposed cap and trade program which have already been developed and then unfairly compares the developed proposal with the mere title "carbon fee" absent a more developed program which would allow for a more reasoned analysis. For example, ARB acknowledges that the efficiency of a carbon fee could be enhanced by pairing it with "complementary approaches, such as performance standards," yet it "assume[s] that only a carbon fee would be implemented." Also, ARB states that to avoid passing costs on to consumers, a system of offsets could be used, but it fails to consider the alternative with such a system and instead criticizes a carbon fee as passing costs onto consumers. Additionally, ARB finds that the potential for leakage is increased with a carbon fee as opposed to a cap and trade system, but fails to consider how to tailor fee levels to market influences, while at the same time stating that it can be done. In ARB's "Comparative Likelihood That Alternatives Achieve Project Objectives," Table 6-1, four objectives are identified as having a "no or low likelihood to achieve objective."

Stated objective six, to be cost-effective, is identified as not likely to be achieved. Nowhere in ARB's discussion of a carbon fee is cost effectiveness directly discussed. In fact, ARB notes so many potential similarities between cap and trade and a carbon fee, without mention of the apparent cost ineffectiveness associated with a carbon fee that one can only speculate as to how cap and trade has a high likelihood of cost effectiveness while a carbon fee has a low likelihood of cost effectiveness. ARB ranks implementation of a carbon fee as unlikely to minimize leakage, in stated objective nine. However, ARB's incomplete analysis failed to consider a carbon fee program that provides opportunities to tailor the fee level to market influences, while at the same time acknowledging that such mechanisms are possible and that they could decrease the potential for leakage. Without conducting an analysis that fully considers what the likely implementation of a carbon fee program would include, ARB's conclusion is preemptive and arbitrary.

ARB's stated objective 18 is to establish a declining cap. This objective is either inapplicable, as this implementation of a carbon fee envisions no cap to begin with, or it is fulfilled by analogy. The intent of the objective is to "cover 85 percent of the state's GHG emissions in furtherance of California's mandate to reduce GHG emissions to 1990 levels by 2020." Since there is no "cap" in this vision of a carbon fee, the objective of a "declining cap" is not applicable. However, the intent of the objective is to continually lower emission levels and this intent could be fulfilled through increasing the carbon fee.

Lastly, stated objective 20 is to link with other WCI partners to create a regional market system. While Table 6-1 concludes there to be no or a low likelihood of achieving this objective, there is no elucidating discussion as to why is it not possible for WCI partners to also adopt a carbon fee. In failing to fully envision, consider, and describe how a carbon fee could operate in California, ARB has failed to provide sufficient information allow a meaningful evaluation of a carbon fee;

(4) California cap and trade program linked with a Federal cap and trade program. ARB discusses the possibility of linking the proposed California cap and trade program to a Federal cap and trade program in the alternatives analysis sections of both the Initial Statement of Reasons and the Functional Equivalent Document. However, linking a California cap and trade program to a non-existent Federal program is not an alternative at all. In fact, it is not an alternative for two reasons. First, an alternative must be an alternative to the proposed program. Here, the proposed program is cap and trade. The alternative discussed is the exact same cap and trade program but with a Federal partner. Ergo cap and trade is not an alternative program to cap and trade, regardless of what partnerships are formed.

Secondly, an alternative that has "no prospect in the near term," contains no detail whatsoever, has envisioned no mechanisms for implementation, enforcement, etc., is not a reasonable alternative. Thus, any linkage between a California cap and trade program and a Federal cap and trade program ought to have been discussed as an alternative cap and trade design feature and not under the guise of a legitimate cap and trade program alternative; and

(5) Alternatives to specific cap and trade program design features. ARB discusses five design features possibly applicable to the proposed cap and trade program. Conspicuously absent from the alternatives analysis is an alternative that geographically limits offsets. (CRPE1)

Response: See response to CRPE1 regarding the reasonable range of alternatives considered in the FED. The FED evaluated a range of market and non-market approaches to GHG reduction. Alternatives consisted of five different cap-and-trade program designs, carbon fee, direct regulation approach, and the no-project alternative. This represents the spectrum of GHG reduction strategies used by states, provinces, and nations.

With regard to comments on the Additional Source-Specific Command-and-Control Regulation Alternative, the commenter disagrees with the conclusions and reasoning presented in the FED, and suggests that additional detail and rationale is required to describe why certain conclusions presented in Table 6-1 were drawn by ARB. The FED provides on pages 387 to 390 a balanced and adequate discussion of the source-specific, direct regulation approach to reducing GHG emissions. It addresses cost, effectiveness, leakage, and local impact issues, and recognizes that it could have some environmental advantage of avoiding any lingering uncertainty about potential for emissions to increase locally. It describes potential environmental impacts being generally similar to the Cap-and-Trade Regulation because the compliance responses would be comparable (i.e., primarily onsite emissions reductions actions). See also CBE1 response. The potential disadvantages of high compliance costs (because of the lack of a market approach that can find the most cost-effective strategies) and the potential for leakage are noted. The additional detail sought by the

commenter is not necessary for an informed consideration of the source-specific, command-and-control approach.

The commenter expresses concern about the ranking of the source-specific, command-and-control approach as not likely to fulfill the objective of linking with other WCI-partner programs. It is important to note that the primary reason for linkage would be to provide for connection of market-based approaches to broaden opportunities for emissions reductions, trading of allowances, or development of offset projects. The direct regulation approach, like the source-specific, command-and-control regulation, is not facilitated by linking with other jurisdictions, which is why its ranking for this objective was low likelihood in Table 6-1.

The commenter criticizes the analysis of the carbon fee alternative and recommends consideration of several variations of the design of a carbon fee program. The FED sought to define a reasonable carbon fee strategy, which is discussed on pages 390 to 393 of the document. Certainly, a wide range of potential design features and concepts could be considered within a carbon fee program. It is not necessary or feasible to evaluate many design variations of a carbon fee strategy to understand its environmental impacts. Because it assigns a price to carbon, the compliance responses and, therefore, the environmental impacts of a carbon fee approach would be similar to cap-and-trade, as noted on page 392 of the FED. The potential for differences is also discussed, in terms of the achievement of project objectives and certain possibilities for environmental effects.

Related to achievement of project objectives, the commenter criticizes the rankings in Table 6-1 for several alternatives and declares that some low likelihood rankings should be "inapplicable" instead (i.e., not ranked for that objective). This change would disguise a potential shortcoming of an alternative. The table compares how well each objective is achieved. If an objective is considered inapplicable for an alternative, it is not fulfilling that objective, and the table shows it as a low likelihood of achieving that objective. Also, the substantiation of the rankings is based on information in the descriptions of alternatives and subsections specifically devoted to consideration of objectives (see subsection a under the Impact Discussion of each alternative). Consequently, the analysis of the carbon fee alternative is adequate for purposes of CEQA.

The commenter indicates that linkage with a Federal program should not have been dismissed from more detailed evaluation. ARB disagrees, recognizing that there is no Federal program, nor the prospect of one because of the lack of Congressional action at this time. Therefore, it would be too speculative to attempt to predict the character and content of a Federal program. Consequently, it is appropriate to not discuss it in further detail.

Finally, the commenter noted that a cap-and-trade design option of geographic limits for offset projects should have been considered. No other detail is provided regarding the commenter's goal for including such a design variation. The success of offsets depends, in part, on allowing for the market sufficient capacity to respond to the opportunity to develop offset projects and offer credits. Constraining the market geographically would also limit market opportunities, so it could hinder an offset program's effectiveness. Because it is not clear what perceived environmental advantage the commenter is seeking to derive from geographic limits, no further response can be provided.

Comment: ARB failed to adequately analyze a range of project alternatives in the Functional Equivalent Document. ARB did not satisfy the CEQA requirement to examine a reasonable range of alternatives. Under CEQA, ARB must examine a reasonable range of alternatives to the proposed project that feasibly meet most of the project's basic objectives while avoiding or substantially reducing the significant effects of the project. CEQA does not supply the number of alternatives that are necessary for a meaningful analysis to take place, but it makes clear that a rule of reason governs requiring the EIR document to set forth "those alternatives necessary to permit a reasoned choice." In the ISOR, ARB purports to analyze four alternatives. In reality, only two alternatives are presented. The "no project" alternative is not a real option in this case given the statutory obligation provided in AB 32. Second, linking a California cap and trade program to a non-existent Federal cap and trade program is not a reasonable alternative for the reasons stated above (see section IV.A.). Lastly, presenting program design features which do not alter the program itself is not a project alternative. For these reasons, a mere two alternatives were considered in the FED. Given the size and implication of a statewide cap and trade program, as well as the broad range of possible avenues to attain the achievement of AB 32, the rule of reason dictates that a reasonable range of alternatives exceed two. Therefore, ARB has failed to satisfy CEQA's requirement to examine a range of reasonable alternatives to the project. (CRPE1)

Response: ARB disagrees with the commenter's assertion that it did not evaluate a reasonable range of alternatives in the FED. The alternatives presented in the FED were selected to evaluate a range of plausible actions that could achieve project objectives. The basis for the selection of the FED's alternatives included:

- A no project alternative is standard in ARB alternatives analyses, and is called for by the CEQA guidelines,
- Consideration of other ways to achieve project objectives is a sound basis for formulation of alternatives, e.g. cap-and-dividend, cap-and-fee, or carbon fee,
- Consideration of public and stakeholder input. ARB held a scoping meeting for the FED (August 23, 2010) for this purpose,
- Alternatives based on ARB's experience and research, and,

- Direct regulations and a carbon fee are the most often cited alternatives to the proposed Cap-and-Trade Regulation, so they were evaluated as alternatives in the FED.

The commenter offers no evidence why the alternatives analysis provided in the FED is not adequate, therefore, no further response is necessary.

Comment: The analysis of offsets produced by manure digesters violates CEQA. The FED finds no impact on air quality and no cumulative impact on air quality from implementation of the Compliance Offset Protocol for Manure Digesters. The FED concedes that engines combusting digester gas emit criteria and toxic emissions. However, the FED assumes that all offset generating projects would be subject to Clean Air Act requirements and local land use decisions that would fully mitigate the criteria and toxic emissions. The FED fails to demonstrate that to be the case, or to require air pollution controls as a condition of receiving offsets. For the same reason, the FED has failed to adequately analyze the emissions of criteria and toxic air pollutants from offsets produced at dairy digesters when there is no reasonable basis to conclude that all such projects would be reduced to a less than significant level (there is no substantial evidence supporting this assumption). (CRPE1)

Response: The commenter states that the FED failed to demonstrate that air quality impacts of offset generating projects would be fully mitigated to a less-than-significant level. The commenter mistakenly states that the FED assumes that all digester facilities would not be subject to Clean Air Act (CAA) requirements. In fact, the Livestock Offset Protocol specifically describes that in order for a livestock digester project to qualify for the offset, it must be implemented in accordance, as required by law, with all applicable federal, state, and local regulations and regulatory oversight requirements. The FED identified (see page 240) that these regulations included federal, state, and local construction and operational air quality permits; CAA and the California CAA; local land use entitlements including environmental (CEQA/NEPA) review; and dust abatement plans for facilities located in PM nonattainment areas. Where a facility would result in a net increase in criteria pollutant (or precursor) emissions in an extreme nonattainment area, it would not be permitted by the local air district. Based on all of these requirements, ARB concluded that the Livestock Offset Protocol would not conflict with adopted air quality plans, violate Ambient Air Quality Standards, and/or result in cumulatively significant increases in criteria pollutants. The commenter offers no other evidence to dispute this conclusion; therefore, no further response is necessary.

Comment: Conclusion. For the reasons set forth above, the Board should not adopt the proposed cap and trade regulation. Instead, the undersigned organizations are asking the Board to consider the impact of the Superior Court's ruling in the pending Scoping Plan challenge, to prepare a proper foundational analysis for whether cap and trade is the maximum feasible and cost-effective reduction, to adopt more appropriate direct regulations and market-based compliance mechanisms than a cap and trade rule, and meaningfully analyze a reasonable range of alternatives in accordance with CEQA.

The Board should seize this opportunity to set California on a path that protects vulnerable communities, fosters green jobs, and stimulates a path to a green economy for California. (CRPE1)

Response: This comment summarizes the commenter's previous comments. See previous responses to CRPE comments.

CRPE4

Name, Affiliation: Sofia Parino, Center on Race, Poverty & the Environment; Maria Covarrubias, Comité ROSAS; Domitila Lemus, Comité Unido de Plainview; Maria Buenrostro, Comité Luchando por Frutas y Aire Limpio; Penny Newman, The Center for Community Action and Environmental Justice; Linda Mackay, TriCounty Watchdogs; Jesse Marquez, Coalition for a Safe Environment; Angela Meszros; Strela Cervas, California Environmental Justice Alliance; Tom Frantz, Association of Irritated Residents; Salvador Partida, Committee for a Better Arvin; Ruth Martinez, Comité Si Se Puede; Ana Ceballor, La Voz de Toniville; Teresa DeAnda, El Comité Para El Bienestar de Earlimart; Gary Lasky, Sierra Club Tehipite Chapter; Shabaka Heru, Society for Positive Action; Caroline Farrell
Written Testimony: 8/11/2011
First 15-Day Comment #: 1110

Comment: The modified Cap and Trade Regulation released on July 7, 2011 is different enough from the version that the Functional Equivalent Document was based upon that it must be recirculated and go through another EIR process before it can be approved in accordance with CEQA. CEQA does not allow the Board to delegate the review of an EIR to the Executive Officer. Because of the failure to complete environmental review before approving the project as well as the substantial modifications to the rule that require recirculation, the full Board must complete the legally-required environmental review process before approving this rule. (CRPE4)

Response: ARB disagrees that the FED must be revised and recirculated. Although the regulation has been amended in several respects, the cap on emissions has remained the same and the method of allocation of allowances has not appreciably changed. ARB staff reviewed 15-Day changes to the regulation language and determined that the proposed changes would not result in new impacts or substantially change the type or significance of impacts disclosed in the FED. Therefore, no revisions were required to the FED. No significant new information was added to the FED and the FED was not changed in a way that deprives the public of a meaningful opportunity to comment upon a substantial adverse environmental effect of the project, or a feasible way to mitigate or avoid such an effect. The public was provided opportunity to comment on the environmental analysis during the initial 45-day public comment period, as well as two subsequent 15-Day comment periods associated with proposed revisions of the Regulation language. Therefore, the requirements that would trigger revision or recirculation of the FED did not occur.

ARB also disagrees that it approved the project in advance of the 15-Day changes or prior to completion of the environmental process. The Board has not taken final action to adopt the proposed Regulation. The Board is scheduled to consider for approval the written responses to comments on the FED at the October 20, 2011 hearing prior to taking final action on the Regulation.

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DWR

Name: Veronica Hicks
Affiliation: California Department of Water Resources
Written Testimony: 12/15/2010
45-Day Comment #: 728

Comment: The environmental impacts of imposing a surrender obligation on DWR were not evaluated. If DWR is required to surrender compliance instruments, it will need to pass these costs on to its water contractors, who in turn will pass the costs on to the end-users of water. An analysis should be conducted to determine the environmental impacts of this regulation. Water is integral to the agricultural sector and important for environmental needs. As reported in the California Water Plan, Update 2009:

> "California is facing one of the most significant water crises in its history- one that is hitting hard because it has many aspects and consequences. Reduced water supplies and a growing population are worsening the effects of a multi-year drought. Climate change is reducing our snowpack storage and increasing the frequency and intensity of floods. Court decisions and new regulations have resulted in the reduction of water deliveries from the Delta by about 20 to 30 percent. Key fish species continue to decline. In some areas of the state, our ecosystems and quality of underground and surface waters are unhealthy. The current global financial crisis will make it even more difficult to invest in solutions. We must act now to provide integrated, reliable, sustainable, and secure water resources and management systems for our health, economy, and ecosystems".

The regulation imposes an additional burden on DWR and California's water users without acknowledging this water crisis or evaluating the impact of this burden under all existing circumstances. (DWR)

Response: The commenter states that the FED does not evaluate the environmental effects of imposing a surrender obligation on DWR and suggests that the additional costs associated with a surrender obligation would result in environmental impacts that were not evaluated in the FED; however, the commenter is not specific as to what those impacts may be.

CEQA does not require discussion of economic changes unless the economic change would result in a physical effect on the environment (see CCR section 15064[e]). The commenter does not provide specifics as to how the economic impacts of the proposed Regulation would cause adverse physical environmental effects. Therefore, it is not possible to meaningfully respond to this general comment, other than to state that we believe the FED adequately evaluates the environmental effects of the proposed project in programmatic analysis in accordance with its CRP.

Higher prices would be expected to increase water conservation and improve the efficiency of water use, which could be considered beneficial effects. Non-CEQA

aspects of this comment are addressed in the FSOR prepared in accordance with APA requirements.

DWR2

Name: Veronica Hicks
Affiliation: Department of Water Resources
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1107

Comment: Did CARB conduct any analysis on the impact of the Regulation on different classes of water users (e.g. urban, agricultural, and environmental)? (DWR2)

Response: The FED provides the environmental analysis of impacts related to compliance responses of covered entities. ARB considered the potential impacts of the proposed Regulation.

Water users would not be subject to the proposed Cap-and-Trade Regulation except to that water purveyors that generate electricity, such as DWR, would be subject to the electrical generation sections of the proposed Regulation. The proposed the Cap-and-Trade Regulation would not regulate the availability, distribution, or use of water. Any impacts to water users that might occur would be the result of secondary price changes associated with electrical generation. A detailed environmental analysis of potential impacts to water users is not necessary under CEQA.

A substantial proportion of the energy consumed in California is used for conveyance and treatment of water, and energy use represents the primary nexus between the proposed Cap-and-Trade Regulation and water. Energy providers (electricity generation and fuel providers) that would be subject to the Cap-and-Trade Regulation may pass increased costs to customers, including customers that use energy to convey and treat water. The proposed market-based program would allow covered entities to seek the least expensive manner of compliance and thus minimize costs. Further, increased costs may result in more efficient use of water. The FED appropriately provides a programmatic level environmental analysis. No direct adverse environmental impacts to water users are expected to result from this activity. The evaluation of indirect environmental impacts that might affect individual classes of water users (most of whom are not regulated entities) resulting from economic changes and the presumed actions of individual water purveyors is beyond the scope of a programmatic analysis and are too speculative to evaluate in the FED.

Comment: Did CARB conduct an analysis identifying the economic and environmental impacts of this regulation, specifically based on impacts to water uses? More specifically, did CARB analyze the impacts on agricultural water users, who may have a disproportionately high level of water use compared to their electricity use? (DWR2)

Response: The commenter questions whether the FED evaluates the economic and environmental effects of the Regulation on water users. Refer to the

response to the preceding comment. Non-CEQA aspects of this comment are addressed in the FSOR prepared in accordance with APA requirements.

Comment: Did CARB consider the economic and environmental impacts such as land use changes and crop-shifting that could result from this regulation's possibly larger impact on agriculture, particularly in light of the assertion by federal power providers that they are not obligated to comply with this regulation, and the resulting incentives which would encourage additional water use on lands entitled to receive federal water deliveries? (DWR2)

Response: Agriculture activities are not directly regulated under the Cap-and-Trade Regulation. Potential indirect impacts to agriculture would be economic, consisting of secondary price changes. CEQA does not require discussion of economic changes unless the economic change would result in a physical effect on the environment (see CCR section 15064[e]). The expected outcome of possible incremental increases in the price of water would be increased water conservation and more efficient use of water, which could be considered beneficial effects. Further environmental analysis is not necessary.

Federal water is allocated based on water rights and not price. The proposed regulation would not change water rights nor would it alter the price of water provided by federal agencies.

ARB prepared the Updated Economic Evaluation of California's Climate Change Scoping Plan, which includes a cap-and-trade program. That evaluation used the ENERGY 2020 model to assess the potential changes in energy use, both type and volume, brought on by the proposed Cap-and-Trade Regulation. The model did not indicate that the use of biomass would increase in response to the proposed Cap-and-Trade Regulation, and consequently crop switching to increase the production of fuel crops or other changes in land use would not be expected. Table 27 of the report demonstrates that potential economic impacts to agriculture from AB 32 climate policies would be comparable to those in other sectors of the economy. Consequently, a detailed analysis of potential economic impacts to agriculture is not warranted. The FED appropriately provides a programmatic level environmental analysis.

DWR3

Name: Veronica Hicks
Affiliation: Department of Water Resources
Written Testimony: 9/27/2011
Second 15-Day Changes Comment #: 2064

Comment: DWR references comments from their earlier comment letters, and asserts that the environmental and economic impacts on DWR and water users have not been addressed.

Response: Refer to responses to DWR and DWR2.

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FRIENDSOFEARTH2

Name, Affiliation: Kate Horner, Friends of the Earth US; Rolf Skar, Greenpeace; Victor Menotti, International Forum on Globalization; Bill Barclay, Rainforest Action Network
Written Testimony: 8/11/2011
15-Day Changes Comment #: 1175

Comment: It is inappropriate for the ARB to move ahead with amendments to, or approval of, these regulations. The ongoing litigation by environmental justice groups under the California Environmental Quality Act raises legitimate concerns regarding the harm of implementing a cap and trade program on California's environment and vulnerable, overburdened communities across the state. As noted by plaintiffs in the case and as we note below, the original regulation failed to meet the criteria set out by AB 32 for market-based compliance mechanisms, and the modifications do not cure these defects. In general, we find that the amendments offered as part of the 15-Day Rulemaking Package do not ensure either environmental or financial market integrity within the proposed cap and trade rules. The ARB should take this opportunity to perform a meaningful and comprehensive alternatives analysis rather than moving forward with the same program at issue in the litigation. (FRIENDSOFEARTH2)

Response: The commenter suggests that because of ongoing litigation on the Scoping Plan, it is inappropriate for ARB to proceed with consideration of the Cap-and Trade Regulation. The commenter further suggests that ARB should prepare a comprehensive alternatives analysis. The commenter references a lawsuit filed against ARB on the Scoping Plan FED. In response to that lawsuit, ARB prepared and circulated the Supplement to the AB 32 Scoping Plan FED (June 13, 2011), which was considered and approved by the Board prior to taking action to re-approve the Scoping Plan on August 24, 2011. The Scoping Plan is a valid approved plan, within which the proposed Cap-and-Trade Regulation is a recommended measure.

The 2008 Scoping Plan outlines the State's strategy to reduce GHG emissions to 1990 levels by 2020, as required by the Global Warming Solutions Act of 2006 (AB 32; Núñez, Chapter 488, Statutes of 2006). A "scoping plan" is required by one provision of AB 32 (Health and Safety Code (HSC) section 38561), and ARB's adoption of GHG reduction measures is authorized under a separate provision (HSC section 38562). It is not required that a particular measure be encompassed in a scoping plan in order for ARB to pursue such a measure as a proposed regulation.

In the Cap-and-Trade FED, ARB evaluated five alternatives to the Cap-and-Trade Regulation, including several iterations of the cap-and-trade program design. The alternatives analysis provides a comparative evaluation of environmental impacts of each alternative (see pp. 365 to 395 of the FED). ARB made a good faith effort to provide a comprehensive analysis of the comparative environmental effects and achievement of project objectives for each of the

alternatives. No specific inadequacies of the alternatives analysis were provided by the commenter; therefore, no further response is necessary.

HDDP2

Name: Bradley K. Heisey
Affiliation: High Desert Power Project
Written Testimony: 12/14/2010
45-Day Comment #: 617

Comment: Based on the HDPP situation, ARB's CEQA review of the proposed Cap-and-Trade Regulation is deficient with respect to 2012 if ARB adopts it as proposed. ARB has not determined the economic or environmental effects of requiring "locked-in" generators like HDPP to purchase 100 percent of their GHG allowances through the proposed auctions at the outset of the program in 2012, with the resulting potential loss of relatively low emitting MWh of energy production in California and replacement by higher GHG emitting electrical generators from the outset of the cap-and-trade program in 2012. (HDPP2)

Response: The commenter suggests that the economic and environmental impacts of requiring "locked-in" generators (i.e., locked into electricity rates by contract) to purchase allowances at auction was not analyzed in the FED.

The first compliance period is now proposed to begin January 2013, a year later than originally proposed. If the Board approves, the Regulation this modification resolves the concern expressed by the commenter.

With regard to environmental impacts, the commenter suggests that the Cap-and-Trade Regulation as proposed would force HDPP (a private utility) to shut down or limit operations in 2012. The concern appears to be the perception that HDPP would be economically penalized for having to purchase GHG allowances without being able to pass the costs of the allowances along to its customers because it is currently operating under a fixed price contract through December 2012 and cannot change the prices to reflect the increased costs of the GHG allowances. The commenter suggests, although the reasoning behind the suggestion is not clear, that higher GHG-emitting electrical generators would replace the lower GHG-emitting electrical generation provided by HDPP in the event of such a shutdown.

The FED provides a comprehensive environmental analysis of the proposed Cap-and-Trade Regulation, including the potential for leakage of emissions outside of California as a result of the cost of allowances and the environmental effects of potential offsets, which are intended to help reduce allowance prices. It is too speculative to suggest that significant or substantially greater environmental impacts would occur as a result of an individual locked-in generator not being able to pass along the GHG allowance costs to their customers. There are many economic, regulatory, and environmental factors to consider. It is not feasible to predict the possibility of closing a power plant (versus other potential compliance responses) because of the cost of allowances. Further, even if electrical generation by lower GHG-emitting

generators would cease or be replaced by higher-emitting GHG generators for 2012, implementation of the overall cap-and-trade program over its 20-year time horizon would result in substantially less GHG emissions compared to baseline conditions, because the declining cap controls overall emissions. This was described as an environmental benefit on page 105 of the FED.

NCPA3

Name: Susie Berlin
Affiliation; McCarthy & Berlin, P.C. for Northern California Power Agency
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1176

Comment: NCPA urges CARB to work with local air quality districts as those agencies undertake CEQA reviews of proposed geothermal projects to ensure that the local air districts apply the same metrics for evaluating a project's impact as CARB does when measuring that impact for compliance with the Cap and Trade Regulation. All of the State's environmental objectives are best served by a uniform and comprehensive approach to the treatment of GHG emissions from geothermal facilities. (NCPA3)

> **Response:** ARB concurs that the State's environmental objectives are best served by a uniform and comprehensive approach to the treatment of GHG emissions, including those from geothermal facilities. ARB will continue to work with the local air districts. Local air districts have discretionary authority in preparation of their environmental analyses and determination of significance of impacts, including GHG impacts.

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NRDC4

Name: Alex Jackson
Affiliation: Natural Resources Defense Council
Written Comment: 12/16/2010
45-Day Comment #: 958

Comment: NRDC believes that the FED is a careful and thorough review of the potential environmental impacts of the cap and trade regulation, in particular in its choice of alternatives to examine. We are also pleased that ARB chose to include adaptive management not as mitigation but rather as part of the program design with respect to forest offset projects and local air quality impacts (FED at 45-47). This use of adaptive management adds legitimacy to the FED in these two areas that have been the subject of much public comment and concern. Moreover, to its credit, ARB is not attempting to take credit for adaptive management as mitigation for recognized, potential negative impacts to air quality or forestry practices. (NRDC4)

> **Response:** This comment supports the alternative analysis and the adaptive management approach. No further response is necessary.

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PCAPCD2

Name: Thomas Christofk
Affiliation: Placer County Air Pollution Control District
Written Testimony: 8/11/2011
15-Day Comment #: 1051

Comment: CEQA should be explicitly distinguished within the regulation because it is not a law that in and of itself imposes reductions requirements. Public Resources Code section 21004 states that "a public agency may exercise only those requirements or implied powers provided by law other than [CEQA]." We recommend that the regulation recognize that offset credits used by a facility for the compliance obligation under the CARB Cap and Trade Regulation should be a part of any CEQA analysis that may be required for that same facility. Offset credits should be taken into account either early on within the setting of the baseline for a project, or as mitigation. The recognition of the purchase of offset credits within the CEQA process is not 'double dipping' because CEQA only requires that a project discloses its impacts. It does not independently provide the legal authority to impose any legal obligation. (PCAPCD2)

Response: The commenter recommends that the regulation recognize that offset credits used by a facility should be part of any CEQA analysis required for that facility, and that offset credits should be identified in the setting of a CEQA document as an existing condition, or as mitigation in the impact analysis. This comment addresses the future treatment of offsets under local CEQA analyses, but does not challenge the adequacy of the environmental analysis prepared for the proposed Cap-and-Trade Regulation. Nonetheless, this document appeared to be a logical location to identify the comment and respond accordingly.

The proposed Cap-and-Trade Regulation establishes criteria for GHG offsets to be used as a compliance mechanism in a market-based reduction program. Offset credits are included in the regulation essentially as cost-containment mechanisms. Under the proposed Cap-and-Trade Regulation, offsets do not mitigate for increased emissions, but rather provide an option to defer expensive onsite improvements during a specified reporting period for covered entities.

The proposed Regulation does not provide for any other use of offset credits, supersede any other air quality regulation that might require GHG reductions, or alleviate the requirement for a lead agency to fully comply with CEQA. ARB rejects commenter's suggestion that the Regulation be amended to allow the use of offsets for CEQA mitigation purposes by lead agencies. Staff does not believe that ARB has the authority to make determinations regarding CEQA mitigation requirements for projects for which it is not the lead agency, e.g. projects that fall within the authority of local permitting authorities. Lead agencies are responsible for determining the baselines for GHG emissions for their respective projects that are subject to CEQA, and for determining the level of significance for impacts. The recognition of offsets in any capacity in a project-specific CEQA analysis is at the discretion of the lead agency and permitting authorities, notably local air

districts for CEQA air quality analyses. ARB staff is not aware of any existing mechanism in the CEQA statute or Guidelines that allows the purchase of an offset credit under the cap-and-trade program as mitigation for projects subject to CEQA.

The environmental impacts of developing a specific offset project consistent with a protocol may need to comply with CEQA. The protocol requires compliance with all other applicable federal and state laws and regulations. The environmental impacts of the offset protocols have been programmatically evaluated in the FED. For example, the Urban Forest Protocol identifies that facilities that pursue this offset could result in increased urban tree plantings the installation of which would result in environmental impacts (e.g., dusts, noise, etc.).

SACREB

Name: Karen Klinger
Affiliation: Sacramento Real Estate Broker
Written Testimony: 12/16/10
45-Day Review Comment #: 983

Comment: There has not been appropriate outreach to the public or full disclosure telling the people what AB 32 really is, what it is linked to, and how all of the other links will accumulatively impact us. Knowing these many links exist, were they included in the DEIR and FEID? (SACREB)

Response: ARB conducted over 30 workshops and public meetings related to the Cap-and-Trade Regulation, including a Scoping Meeting for the FED, available at the following website:

http://www.arb.ca.gov/cc/capandtrade/meetings/meetings.htm#archive.

ARB provides an assortment of AB 32 and Climate Change fact sheets that can be downloaded from the ARB website, and has web pages that are developed for specific audiences such as, general public, small business, local government, students and teachers. The FED was noticed in a 45 day Notice of Proposed Regulatory Action posted on ARB's website, noticed and circulated through the State Clearinghouse for agency review and comment, and publicly noticed in major newspapers in northern and southern California.

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USFLAW

Name: Alice Kaswan
Affiliation: University of San Francisco School of Law
Written Testimony: 12/10/2010
45-Day Comment #: 486

Comment: Alternative Rejected by Staff – Implement Only Additional Source-Specific Command-and-Control Regulations. CARB staff rejected the alternative of replacing the cap-and-trade program with a direct regulatory program for industrial sources. The Staff Report presents a number of convincing arguments for why regulation should not replace a cap-and-trade program, but did not address the value of complementing the cap-and-trade program with limited and targeted regulatory efforts where appropriate. The Staff Report expresses concerns about the cost-effectiveness of regulation if applied to all industries. But if regulation were used to complement cap-and-trade only where appropriate, CARB could take cost-effectiveness into account in deciding whether to impose regulations. In determining cost-effectiveness, it is also important for CARB to consider not only the costs of regulation to the relevant industry, but also the economic benefits of enhanced emissions reductions.

The Staff Report also observes that regulations would be difficult to draft given the lack of data on effective emission reduction mechanisms and the variation among facilities. However, CARB is requiring energy audits at industrial facilities, a process that includes an assessment of associated co-pollutant impacts. While current data may be insufficient, the audits could provide a much stronger basis for identifying cost-effective energy efficiency mechanisms that could be required at industrial facilities, and that could achieve both GHG and co-pollutant reductions.

CARB staff may be assuming that facilities will adopt cost-effective reduction strategies in response to the price signal created by the cap-and-trade program, without the need for command-and-control regulations. But industrial investment decisions are complex. Inertia, uncertainty about future carbon markets, concerns about short-term capital expenditures, and other factors could impede otherwise cost-effective investment in emission reductions. If price signals do not end up prompting cost-effective measures with significant co-pollutant benefits, then CARB should retain the authority to require appropriate measures.

In addition, if CARB identifies cost-effective GHG emission reduction measures with particularly significant co-pollutant benefits, then it would be consistent with AB 32's goals to require those measures rather than relying upon the vagaries of the market to incentivize them. Co-pollutant benefits could be particularly significant either because GHG reductions lead to a large reduction in associated co-pollutants, and/or because the industries to be regulated are located in especially polluted areas. (USF-LAW)

> **Response:** See response to CRPE1 regarding the reasonable range of alternatives considered in the FED and source-specific alternative response.

ARB believes that it has provided a reasonable range of alternatives for evaluation under the FED.

It is also important to note that ARB always retains the ability to pursue additional regulations. In fact, ARB is currently collecting information on opportunities for further GHG and co-pollutant emission reductions through the Energy Efficiency and Co-benefits Assessment Regulation for Large Stationary Sources. ARB is scheduled to receive these data by the end of 2011. Staff would then initiate a process to ensure that large industrial sources subject to the regulation be required to take all cost-effective and technically feasible actions identified under those audits. The audit results, due to ARB by the end of 2011, will inform the development of regulatory requirements staff intends to propose to the Board in 2012. Staff plans to initiate a separate public process in Fall 2011 to discuss metrics and actions to implement this commitment.

Also see the response to CBE1 regarding ARB's plans to implement an adaptive management plan.

Comment: In all provisions relating to the burning of biomass and biofuels, CARB should carefully assess associated co-pollutant and other environmental implications. For example, if biomass-derived fuel sources do not have to account for their GHG emissions, the rule could create incentives to use biomass that have incidental adverse environmental consequences. (USFLAW)

Response: The increased use of biomass is already incentivized by existing regulations such as the Renewables Portfolio Standards and the Low Carbon Fuel Standard. The Renewables Portfolio Standard (RPS) requires public owned utilities to obtain 33% of their energy from renewable resources. Most utilities are challenged to achieve the renewable target despite the availability of biomass as a renewable fuel.

ARB used the ENERGY 2020 model to assess the potential changes in energy use, both type and volume, brought on by the proposed Cap-and-Trade Regulation. The model did not indicate that the use of biomass would increase in response to the proposed Cap-and-Trade Regulation. Further, the proposed Cap-and-Trade Regulation would not supersede other air quality regulations. Combustion of biomass is subject to local permitting and emission control requirements.

ARB proposes to monitor the use of biomass as part of our monitoring and oversight of the implementation of the Cap-and-Trade Regulation.

VALERO2

Name: Matthew H. Hodges for Patrick Covert
Affiliation: Valero Companies
Written Testimony: 8/11/2011
First 15-Day Changes Comment #: 1062

Comment: It is presumptuous of CARB to continue development of a cap and trade regulation when the alternatives discussed in the Supplement to the AB 32 Scoping Plan Functional Equivalent Document (FED) have not been fully vetted. With the FED public comment period closing on July 28, 2011, CARB has not had sufficient time to consider all comments and respond appropriately. From a general perspective, the FED was a hastily prepared document lacking in critical details that draws upon a foregone conclusion that California must have a cap and trade regulation to meet the goals of AB 32. Resolution 10-42 (approved at a December 16, 2010 Board Hearing to consider adoption of the proposed Cap and Trade program), requires the Executive Officer to report on the progress being made on implementing the Cap and Trade program, provided the Cap and Trade program is approved. In the absence of a complete review of comments submitted in response to the FED and making a formal determination that other alternatives are not feasible or appropriate, it appears premature to continue the Cap and Trade rulemaking process. (VALERO2)

> **Response:** ARB prepared and circulated the Supplement to the AB 32 Scoping Plan FED (June 13, 2011). At a public hearing on August 24, 2011,the Board, after consideration of the alternatives analysis in the Supplement, public comment and staff's written responses to comments, voted to re-approve the Scoping Plan. The responses in this document incorporate information from the Scoping Plan FED Supplement as appropriate.

Comment: Valero strongly urges ARB to complete the regulatory development process prior to adoption, including full consideration of comments and alternatives presented in the FED, so that all impacts can be thoroughly reviewed as an entire package by the impacted parties. Valero believes that, if ARB presents a complete regulatory package, the impact to the economy, industry and consumers would be minimized. (VALERO2)

> **Response:** The commenter urges ARB to complete the regulatory process prior to adoption of the project, including full consideration of comments and alternatives presented in the FED. ARB has put forward a good-faith effort in preparing the FED for the Cap-and-Trade Regulation that was circulated for public review and comment, and staff has prepared written responses to comments on the FED in this document. The Board is scheduled to consider the FED, comments on the FED, staff's written responses to those comments, prior to taking final action on the proposed Regulation at a public hearing on October 20, 2011.

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III. EVALUATION OF REGULATORY (PROJECT) CHANGES

The Draft FED was included as Appendix O to the Staff Report prepared for the Regulation, and was circulated for public review and comment from October 28, 2010 to December 16, 2010. Since circulation of the FED, the Regulation language was modified, and two Notices of Public Availability of Modified Text and Availability of Additional Documents were issued.

The first 15-Day Change clarifies and revises the Regulation language to allow California's cap-and-trade program to better align with rulemaking efforts in other Western Climate Initiative (WCI) jurisdictions. These changes allow for future linkage that supports a broader, regional cap-and-trade program, provides more cost containment benefits to California-covered entities, and ensures greater reductions in regional emissions of greenhouse gases to the atmosphere. Staff also modified the Regulation language to begin the first compliance obligation in 2013. The allocation, auction, trading, and other activities will begin in 2012 before the start of the compliance obligation and the first compliance period. The 15-Day Change language provides that three-fourths of the "excess emissions" will be placed into the auction holding account, and not in the price containment reserve. Staff added flexibility to the statutes of limitations for invalidation of ARB offset credits, and added an equation to calculate how a compliance obligation would be assessed for electricity providers. The notice of the first 15-Day change can be found at: http://www.arb.ca.gov/regact/2010/capandtrade10/2nd15daynotice.

The second 15-Day Change modifies or clarifies numerous sections of the Regulation, including those sections that apply to roles and responsibilities of covered entities, accounting and tracking, ensuring confidentiality and security of account representatives, and other key program design elements. The second notice can be found at: http://www.arb.ca.gov/regact/2010/capandtrade10/2nd15daynotice.pdf.

In addition, the general offset provision was modified to be more stringent, and the four Compliance Offset Protocols analyzed in the Draft FED were modified. These changes generally resulted in the protocols to be more environmentally protective. The Urban Forest Projects Protocol was modified to require an urban forester to be involved in the review of the project and offset project data report. The Livestock Projects protocol was modified to allow some mechanical flexibility, and thermo couplers for flares have been expanded to include engines, as well as adjustments to metered biogas flow data were replaced by a more conservative method to ensure rigorous accounting. The Ozone Depleting Substances Protocol was modified to include CFC-13 as an eligible gas into the methodology based on information from U.S. Environmental Protection Agency, and others. The U.S. Forest Project Protocol was modified to be more stringent by incorporating administrative, procedural, and legal provisions identified earlier in this document.

ARB staff reviewed the regulatory language modifications and evaluated whether they warranted any revisions to the environmental analysis in the FED, e.g. to reflect any new impacts or levels of significance of identified impacts. Staff has determined that the

modifications consist largely of administrative and program design modifications that would not change the results or findings of the environmental analysis in the FED. Therefore, revision of the environmental analysis or recirculation the FED for further public review and comment is not required.

IV. REFERENCES

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California Air Resources Board. *Final Supplement to the AB 32 Scoping Plan Functional Equivalent Document. Attachment D of the FSOR.* Released August 19, 2011to be considered at the August 24, 2011 Board Hearing. http://www.arb.ca.gov/cc/scopingplan/document/final_supplement_to_sp_fed.pdf

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California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan. Staff Report to the Air Resources Board.* March 24, 2010. http://www.arb.ca.gov/cc/scopingplan/economics-sp/updated-analysis/updated_sp_analysis.pdf

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California Environmental Protection Agency

Air Resources Board

Proposed

Adaptive Management Plan for the Cap-and-Trade Regulation

October 10, 2011

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I. Executive Summary

This document describes the Air Resources Board's (ARB or Board) recommended adaptive management plan. The plan is focused on two specific areas: localized air quality impacts from the proposed cap-and-trade regulation (cap-and-trade regulation or Regulation) and forest impacts from the proposed Compliance Offset Protocol for U.S. Forest Projects (U.S. Forest Protocol) contained in the Regulation. The plan is being released for public comment, and will be presented to the Board for consideration at the October 20-21, 2011, Board meeting. If adopted, the plan will require ARB to take a range of actions in these two areas to monitor and respond as appropriate to address unanticipated adverse impacts that are caused by the Regulation or the U.S. Forest Protocol.

Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency's decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives – as in the case of the proposed Regulation. Adaptive management is consistent with ARB's long-standing approach to program implementation which incorporates on-going evaluation of how programs and regulations are implemented on the ground, regular updates to the Board, and adjustments to program implementation and regulatory requirements, as necessary.

In this plan, ARB is focusing on the two aforementioned areas where, although not anticipated, unintended environmental impacts could occur. The adaptive management plan focuses on these two areas because they were identified in the environmental analysis accompanying the rulemaking as areas where the potential for unanticipated impacts could occur and because they were specifically identified as being of special concern in public comments. It is important to note, however, that this focused adaptive management plan should be viewed in the larger context of ARB's planned oversight of the proposed Regulation and the U.S. Forest Protocol, which includes comprehensive monitoring of auctions, reserve sales, allowance holdings, compliance offset credit generation and use, reported emissions, leakage, and other aspects of the Regulation. Additionally, the adaptive management plan should also be viewed in the context of ARB's larger air pollution control programs, which already incorporate systems to measure air quality and emissions in an effort to continuously improve air quality in California.

Plan Elements

The key elements of this adaptive management plan are: (1) data and data source identification (information gathering); (2) analysis to determine whether an adverse impact is caused by the cap-and-trade regulation (review and analysis); and (3) identifying potential actions ARB could take to address these impacts and committing to take appropriate action (response).

What Data Will ARB Gather for Evaluation?

ARB identified data sources for the evaluation of potential localized air quality impacts. These include cap-and-trade specific data such as greenhouse gas (GHG) emissions, and the holdings of allowances and compliance offset credits, as well as traditional criteria pollutant and air toxics information such as air pollution control district permits, air monitoring data, and emission inventories. If the Board approves the Regulation and this plan, ARB will work with local air districts and stakeholders to refine plan details concerning air quality data gathering prior to initiation of the first compliance period on January 1, 2013.

ARB has identified data sources for the evaluation of potential unanticipated forest impacts resulting from the U.S. Forest Protocol. These include information that must be reported under the protocol, as well as emission inventories, timber harvest plans, the Fire and Resource Assessment Program, and information from other states (should forest offset projects occur in other states). As part of the adaptive management plan, ARB intends to contract with an independent third-party to assist in determining the best ways to filter and analyze the data needed to evaluate potential unanticipated impacts in this sector. ARB will work with the appropriate agencies and stakeholders to refine plan details related to data filtering and analysis.

How Will ARB Review and Analyze the Data?

As part of this plan, ARB will analyze the collected data to determine whether an environmental change such as an increase in emissions has occurred, and whether the change is caused, directly or indirectly, by the cap-and-trade regulation or the U.S. Forest Protocol. If the analysis indicates a change has occurred as a result of the Regulation or U.S. Forest Protocol, ARB will evaluate whether such change had or is likely to have an adverse impact.

It is unlikely that ARB will be able to rely on any single analysis or data source. The complex interplay of possible economic drivers, as well as other regulatory drivers, will most likely require ARB to conduct multiple analyses. It may not be possible to identify a direct causal relationship between the environmental change and the Regulation or U.S. Forest Protocol. Therefore, ARB will evaluate the weight of available evidence to determine the reason for the change.

In conducting the analysis, it will be necessary to consider normal variations, existing trends, and other factors that may be responsible for changes in the data. For example, air quality data can vary significantly from year-to-year because of meteorology. Additionally, changes in economic activity can produce large impacts on air quality and emissions trends, and factors such as rainfall can have significant impacts on emissions as a result of California's utilization of hydroelectric power as a source of energy.

The following is an illustrative example of the stepwise approach ARB will take to analyze the data for determining a localized impact:

- Monitor facilities subject to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) for GHG emissions increases. Increases in GHGs could indicate that an increase in other pollutants has occurred. If an increase is apparent, then;
- Review indicators to assess if the change was caused by the Regulation (e.g., the result of a compliance response to the Regulation) or some other factor (e.g., the result of increased production due to economic growth). If the change is determined to be caused by the Regulation, then;
- Work with the local air district to review co-pollutant emissions for appropriate sources and geographic areas to determine whether the change had or is likely to have adverse impacts on local air quality.

How Will ARB Respond?

In the event that an unanticipated adverse localized air quality or forest impact is identified and determined to have been caused by the Regulation or U.S. Forest Protocol, this plan requires ARB to take action to respond appropriately. While it is not feasible in this plan to identify all potential actions that could be pursued, ARB is committed to promptly developing and implementing appropriate responses through a public process, including consideration and approval by the Board as necessary.

ARB would consider a range of options to address localized adverse air quality impacts. These could include the adoption of additional regulatory requirements, using funds obtained from the sale of allowances to support local mitigation projects, coordination with other agencies to provide additional incentives for energy efficiency or other emission reduction activities within the community, or modifications to the Regulation.

For unanticipated impacts from the U.S. Forest Protocol, ARB could consider revising the types and/or geographic location of forest offset projects, or disallowing the use of certain types of U.S. Forest Protocol compliance offset credits. Other types of responses are also possible and would be considered and implemented as necessary.

Public Process for this Adaptive Management Plan

ARB is soliciting comments on this plan. The Board will consider this plan at its October 20-21, 2011, Board meeting. Interested members of the public may present comments orally or in writing at the meeting, and comments may be submitted by postal mail or electronic submittal before the meeting.

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

Upon Board approval, ARB will work with our local air district partners, departments of the Natural Resources Agency (resource agencies), and stakeholders to implement the plan based on the following schedule:

October 10, 2011	ARB releases Draft Adaptive Management Plan for comment.
October 20-21, 2011	Board considers Adaptive Management Plan for approval.
November 2011	Staff works with local air districts, resource agencies, and stakeholders to finalize specific details concerning data gathering under the Adaptive Management Plan.
Early 2012	ARB contracts for third-party forestry expertise.
Mid-2012	Staff updates Board on Adaptive Management Plan implementation.
December 2012	Staff releases Adaptive Management Implementation Report (prior to first compliance period).
December 2013	Staff updates Board on Adaptive Management implementation.
December 2014	Staff releases Adaptive Management Report for calendar year 2013.
December 2015	Staff releases Adaptive Management Report for calendar year 2014 and end of first compliance period.
Ongoing	Staff releases Adaptive Management Report annually.

II. Introduction

In December 2010, ARB considered the proposed cap-and-trade regulation. As part of the rulemaking, an environmental impacts analysis was prepared and included in Appendix O to the Staff Report: Initial Statement of Reasons and entitled Functional Equivalent Document (FED). The environmental analysis concluded that increases in localized air pollution or forest project related impacts caused by the Regulation or U.S. Forest Protocol are unlikely based on available data and current laws that control localized air pollution and regulate forest activities. However, ARB could not determine that increases would not ever occur. In addition, commenters raised concerns about the potential for localized air impacts and the potential for impacts to forest resources related to forest offset projects. ARB, therefore, committed to use an adaptive management approach as an integral part of the implementation of the cap-and-trade program in order to address unanticipated impacts that could result from the Regulation related to these two specific areas.

The areas of focus in this adaptive management plan are localized air quality impacts and impacts from the U.S. Forest Protocol on special status species, sensitive habitats, and federally protected wetlands (hereafter referred to as forest impacts). It is important to note, however, that the elements of monitoring, review, and feedback contained in adaptive management will be more generally applied to the cap-and-trade regulation to ensure that all of its objectives, including GHG emissions reductions, are achieved. Accordingly, the focused adaptive management plan in this document must be viewed in the larger context of our planned oversight of the cap-and-trade regulation which includes comprehensive monitoring of auctions, reserve sales, allowance holdings, compliance offset credits generation and use, reported emissions, leakage, and other aspects of the program.

The plan includes a description of what is meant by adaptive management, ARB's objectives in implementing the plan, and a process for systematic data compilation, evaluation, and public review. The key elements of this adaptive management plan are: (1) data and data source identification (information gathering); (2) analysis to determine whether an adverse impact is caused by the cap-and-trade regulation (review and analysis); and (3) identifying potential actions ARB could take to address these impacts and committing to take appropriate action (response).

Staff anticipates that data gathering will be straightforward. The work of review and analysis, however, will be challenging because there could be many reasons for a change in localized air emissions or forest management practices. Examples are a change in laws unrelated to the Regulation; economic growth related to recovery from the economic downturn; adoption of a new technology within an industry; and increased consumer demand for a specific product.

Under the plan, ARB staff would work with the local air districts where facilities subject to the Regulation are located in an effort to refine a specific, systematic approach for efficiently compiling, interpreting, and evaluating the data. Because ARB is not expert

in forestry practices, ARB plans to contract with an independent third-party (ARB contractor) to assist it in determining the best ways to filter and analyze the data needed to evaluate potential, unanticipated impacts related to forestry.

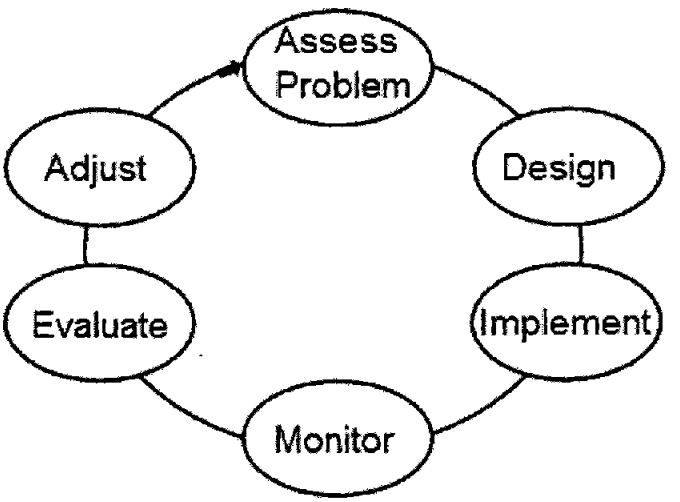
ARB will consider approval of this plan at the October 20-21, 2011, Board meeting. Upon Board approval, ARB will work with the local air districts, resource agencies, and stakeholders to implement the plan. The timeline for completion of this work is before the beginning of the first compliance period in January 2013. The first adaptive management report is planned for December 2012, and will focus on the first phase of implementation. Annually thereafter, staff will provide reports to the public and the Board on the implementation of the adaptive management plan. The annual adaptive management plan reports will, among other things, outline the data collected and the trends observed, and discuss any recommended responses.

III. Adaptive Management

Adaptive management is a process of information gathering, review and analysis, and response that promotes flexible agency decision-making. It is particularly appropriate where complex systems are involved, where the effects of an agency's decisions and actions play out over an extended period of time, and where the agency must meet multiple objectives – as in the case of the proposed Regulation. Adaptive management is consistent with ARB's long-standing approach to program implementation which incorporates on-going evaluation of how programs and regulations are implemented on the ground, regular updates to the Board, and adjustments to program implementation and regulatory requirements, as necessary.

Figure 1, representing the adaptive management process, illustrates how new information is used to refine and adjust agency action to continually meet its defined objective[1].

Figure 1: Adaptive Management Process



Implementation of the cap-and-trade regulation is expected to begin in January of 2012 (assuming it is approved by the Board). Using the adaptive management approach, ARB will assess whether there are unanticipated, adverse localized air quality or forestry impacts from the Regulation or U.S. Forest Protocol and evaluate the data discussed in this plan for indicators of unintended adverse impacts. If adverse impacts in these areas are found and demonstrated to be the result of the Regulation or U.S. Forest Protocol, ARB is committed to taking appropriate action and adjusting the operation of the program to minimize the effect or occurrence of the action that caused the impact.

A. Objectives of ARB's Adaptive Management Plan

The objectives of ARB's adaptive management plan include:

- Identify potential localized emission increases and forest impacts caused by the cap-and-trade regulation.
- Establish a process to address unanticipated adverse local air quality and forest impacts.
- Keep the public and Board informed of impacts attributed to the cap-and-trade regulation.

[1] United State Department of the Interior: http://www.doi.gov/initiatives/AdaptiveManagement/whatis.html

The strategies that ARB will employ to achieve these objectives include:

- Identify data sources.
- Use data to assess if there has been or is anticipated to be an increase in localized emissions or change in forest ecology.
- Assess if the change is caused directly, or indirectly, by the cap-and-trade regulation.
- Use data to assess if there has been or is anticipated to be an adverse impact.
- Share data and reports with the Board and public annually.
- Report to the Board as needed but, at a minimum, annually in conjunction with the issuance of the annual adaptive management plan report.
- Take appropriate action to address any adverse impacts related to localized emissions or forestry caused by the Regulation.

B. Questions that Frame Review and Analysis Under the Adaptive Management Plan

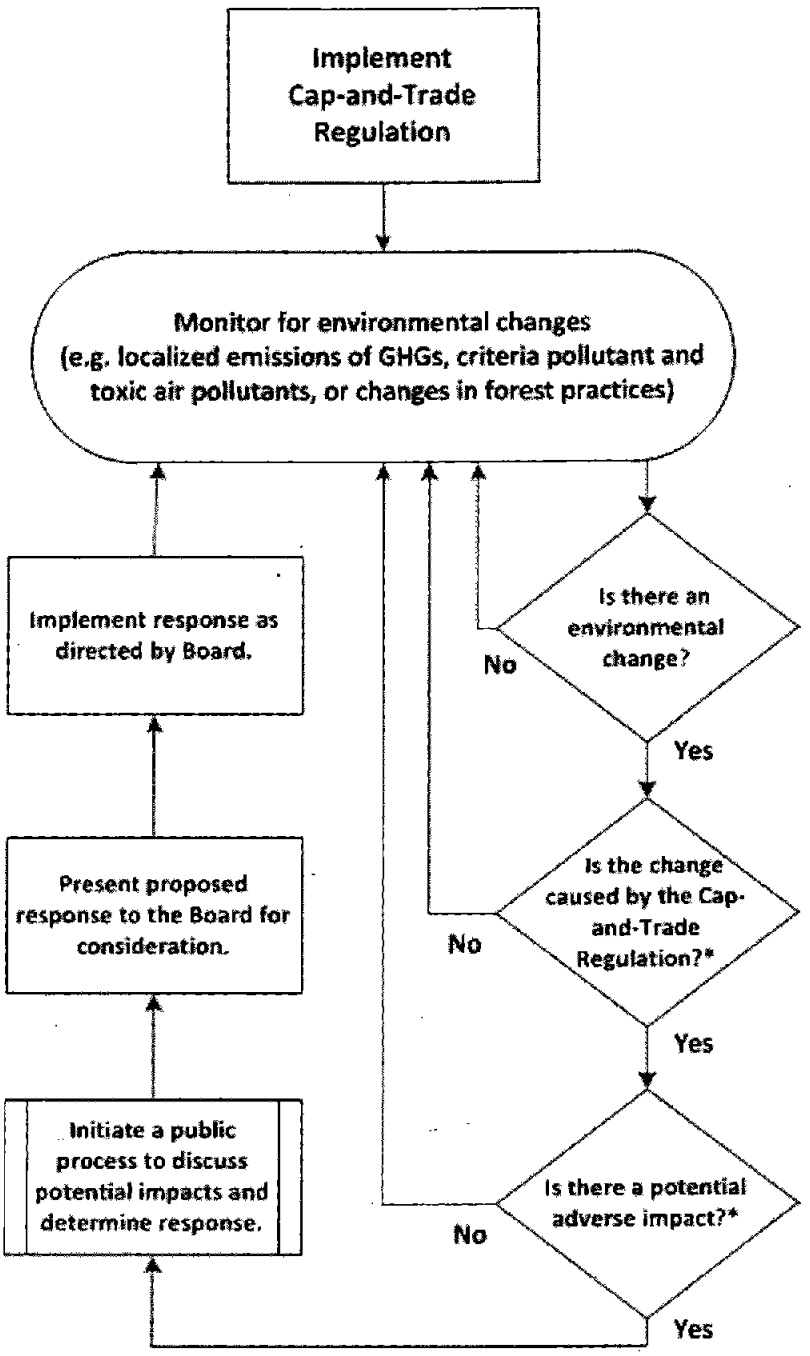
The key questions that must be answered on an on-going basis by the adaptive management plan are:

- Has an environmental change (e.g., increase in emissions or transition in forest practices used) occurred?
- Is the environmental change caused, directly or indirectly, by the cap-and-trade regulation or U.S. Forest Protocol?
- Has the environmental change had an adverse localized air quality or forest impact?
- What action could ARB take to address an adverse impact linked to the cap-and-trade program or U.S. Forest Protocol?

The key elements of this adaptive management plan are: (1) data and data source identification (information gathering); (2) analysis to determine whether an adverse impact is caused by the cap-and-trade regulation (review and analysis); and (3) identifying potential actions ARB could take to address these impacts and committing to take appropriate action (response).

Figure 2, representing the flow of ARB's adaptive management plan, illustrates how ARB will implement adaptive management, monitor and evaluate data, and make adjustments to the Regulation, if necessary.

Figure 2: ARB Adaptive Management Plan Flow Chart



* These questions will be addressed based on the evaluation of a range of data sets and will involve technical judgment and other available tools and methods.

IV. Information Gathering

In this section, ARB discusses the information to be gathered for review and evaluation. Because this section discusses at various places why staff is gathering certain data – that is, why it is relevant – this section also necessarily previews the next section on analysis and review.

A. Localized Air Quality Data

ARB identified data sources for the evaluation of potential localized air quality impacts. These include GHG inventories, traditional criteria pollutants and air toxics emissions data, local air district or state agency permit information, air monitoring data, special monitoring studies, and other sources of data including new cap-and-trade program specific data such as GHG emissions, and the use of allowances and compliance offset credits to comply with the Regulation. If the Board approves this plan, ARB will work with local air districts and stakeholders to finalize specific details concerning data gathering, including the best means to transmit, filter, and analyze the data for localized air quality impacts, and complete the details before initiation of the first compliance period in January 2013.

It is important to remember that many factors can cause changes at facilities, and that once an increase has been detected, additional sources of data must be used to assess if the increase is the result of the cap-and-trade regulation. Below are a number of sources of information that ARB will consider in determining if an adverse impact resulting from the cap-and-trade regulation has occurred or will occur. As ARB implements the adaptive management plan, it may find additional sources of data to include or it may find that some sources of data are not useful to continue to monitor.

1. Greenhouse Gas Mandatory Reporting Regulation (MRR)

Reporting of annual GHG emissions by major sources is required by AB 32. ARB approved the MRR in December 2007, and it became effective in January 2009. Revisions to the regulation were considered by the Board at its December 2010, Board hearing, and ARB staff is proposing additional modifications based on Board direction and stakeholder comments, prior to finalizing the regulation for 2012 reporting. More on the MRR can be found at:

http://arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm

The current MRR requires reporting emissions of six GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6). It is applicable to: facilities in California that generate 25,000 metric tons of CO_2 per year ($MTCO_2$/year) or greater; electrical generating facilities that produce 1 megawatt (MW) or greater, or that generate 2,500 $MTCO_2e$ or greater per year; and retail providers and marketers of electrical power. Facilities report directly to ARB, and are required to use the methodologies in the MRR,

providing consistency across the State. The first reporting year was in 2009 (for 2008 data, which was not third-party verified). Beginning in 2010 (for 2009 data), the reported data were subject to third-party verification by ARB-accredited verifiers, which requires that data are reported within ninety-five percent accuracy. For 2010 (2009 data), about ninety-five percent of all reporting facilities were able to report their data with less than five percent error. The verification deadline is currently December 1.

The pending, proposed amendments to the MRR cover three GHGs: CO_2, CH_4, and N_2O. The other gases that were previously covered are proposed to be covered in various new regulations (e.g., high global warming potential gases and SF_6 regulations). The proposed amendments are applicable to: facilities in California that generate between 10,000-25,000 $MTCO_2e$/year (no verification) and 25,000 $MTCO_2e$/year or more (verification required); fuel and CO_2 suppliers; and electric power entities. The first reporting year is in 2012 which will include 2011 emissions data that are third-party party verified. The verification deadline will be September 1 starting in 2012 and continuing in future years.

The GHG MRR database involves the collection of total annual combustion emissions for a facility by fuel types and includes specific chemical process emissions. Device-level emissions are limited in most cases. Thus, MRR GHG data are summarized at a higher level than the criteria pollutant California Emission Inventory Development and Reporting System (CEIDARS) inventory, which is available at the device and process level. However, the GHG data are reported annually and available approximately nine months after the end of the inventory year making it the most current data source in any year. Due to differences in the level of detail in data collected from these two sources, it may be difficult to evaluate consistency in emissions trends.

The MRR data could be used to track increases in GHG emissions, or equipment changes at facilities covered under the proposed Regulation, identify fuel type changes, and help point to potential impacts resulting from co-pollutants.

2. Compliance Instrument Tracking System

The Compliance Instrument Tracking System will contain the records of compliance instrument ownership for the Regulation. It will contain information related to accounts, record compliance instrument transfers, facilitate compliance verification, and support market oversight. Reviewing the number of compliance offset credits and allowances held by facilities covered by the proposed Regulation could provide information on potential plans to increase emissions at a facility. It is important to note that holdings in these accounts are confidential data, and therefore, this information will not be publicly available, but can be monitored by ARB staff.

3. Local Air District Permits for Covered Entities

Local air districts permit stationary sources that are sources of air pollutants. These permits are required prior to construction of new facilities or modification at existing

facilities subject to local air district regulations. Additionally, the facility must maintain its permit and continue to abide by the restrictions contained therein to continue to operate.

Local Air District Existing Permits

The permitted level of emissions is typically based on the maximum expected throughput or maximum rated capacity of a piece of equipment or process. It is possible that emissions increases could occur at a facility and the facility would still meet the legal requirements of their operating permit. Because of this, permit activity will not show increases that may have occurred within the conditions legally authorized by the existing permit(s). However, information from these permits could still provide valuable insight into whether a facility covered under the proposed Regulation has, or could, increase emissions by understanding emissions trends for existing facilities.

Local Air District Permits to Modify Facilities Covered by Cap-and-Trade Program

When construction of a new facility, or modification to an existing facility, is proposed, the facility operator must apply with the local air district for permission to construct most equipment that will emit criteria or toxic pollutants. This permission is known as a permit to construct or authority to construct. Not all proposed facilities that are issued a permit or authority to construct are constructed.

A local air district conducts an engineering evaluation on the equipment and processes in the permit application to determine the potential emissions. The proposed construction is evaluated for emissions of criteria pollutants and local impacts of emissions of toxic air pollutants, if applicable. The project is typically subject to requirements under its permit conditions that reduce emissions (known as controlled emissions), depending on factors such as the attainment status of the local air district or the local impact of toxic air pollutant emissions from the project. Additionally, most projects that require a permit to construct generally are subject to the California Environmental Quality Act (CEQA). Projects that will have a significant effect on the environment must undertake feasible mitigation. It is important to note that the local air district may, or may not, be the lead agency in the CEQA assessment.

As part of this permitting process, local air districts' rules to meet federal and State requirements for new source review (NSR) programs may be applicable, especially to large sources covered under the Regulation. These rules are intended to improve or maintain a region's air quality by assuring that new emissions from new and modified facilities do not slow progress toward cleaner air or worsen air quality in regions that attain air quality standards. The best available control technology (BACT) provisions of NSR provide assurance that emissions from any large new or modified industrial source will be stringently controlled. Additionally, if new construction or modification results in the facility exceeding a district's NSR offset thresholds, then the facility must either reduce emissions elsewhere at the facility or obtain emission reduction credits (ERCs) in amounts greater than the direct emissions increase. These ERCs must be obtained from within the region or from areas close by, thus mitigating the increase in emissions at the facility in terms of regional air quality.

Working with local air districts, ARB will implement a process to track permit applications for modifications to facilities subject to the Regulation, or for construction of new facilities that would be subject to the Regulation.

4. California Energy Commission (CEC) Power Plant Permitting

The CEC permits thermal power plants that have the capacity to generate fifty megawatts (MW) or greater. Local municipalities permit those with less than a fifty MW generating capacity. Local air districts also permit power plants that are combustion sources. However, CEC and local municipality permits may provide greater advanced notice of proposed facilities. Additionally, the CEC tracks announced projects with generating capacity of 50 MW or greater that have not yet filed for review. Not all facilities that are issued a permit are constructed. ARB currently works with CEC to track permit applications for construction of new power plant facilities or modification of existing power plant facilities.

5. Economic Forecast Data

A variety of economic forecast data are available from local, State, and federal agencies. Including forecast data in the analysis will be useful for evaluating the proportion of emission changes related to economic factors. Examples of specific forecasts from agencies that could be used include economic and energy forecasts based on the estimates adopted by the CEC published in Integrated Energy Policy Reports. Examples of academic economic forecasts that could be used include the California and Metro forecast published by the Business Forecasting Center at the University of the Pacific and the UCLA Anderson Forecast published by the Anderson School of Management at the University of California, Los Angeles. ARB will use these types of economic forecasts for comparison with emissions trends to determine if emissions are consistent with changes in the economy, or in specific economic sectors. If emissions are substantially different than changes in the economy, then the data could suggest that changes in emissions are related to factors other than economic change.

6. Air Quality Monitoring Data

In California, ambient air quality is routinely measured for gaseous, toxics, and particulate air pollutants. The extensive network is designed to cover the diverse range of topography, meteorology, emissions, and air quality in California, while adequately representing a large population. In general, the network tends to be denser in areas with more severe air quality problems and in areas with larger populations. The monitoring stations are operated by ARB, local air districts, the National Park Service, and private contractors.

The data collected by the monitoring network are used to track air quality progress, evaluate emissions inventory and air quality models, analyze neighborhood or regional source attribution, and evaluate the success of emission control programs. The

measured data form a backbone for air quality management programs, provide the public with information on current conditions and progress in improving air quality, and are used by health researchers, business interests, environmental groups, air quality planners, and others.

The ambient air quality monitoring network captures data representative of a broad range of sources and regions throughout the State. Monitors are designed to represent pollutant levels on different spatial scales, ranging from near-source localized impacts up to broad regional-scale conditions. Although a few monitors are located so they will represent small areas dominated by specific local sources, most monitors are designed to represent the combined impact of multiple, distributed sources over the scale of a neighborhood or city or more. Thus, detecting the impact of changes at an individual facility can be difficult.

Monitors are also designed to represent different periods of time. A number of pollutants, including gaseous pollutants such as ozone (O_3), oxides of nitrogen (NO_x), and carbon monoxide (CO) are reported hourly. Many other pollutants, such as particulate matter (PM), hydrocarbons, and toxics are typically measured as 24-hour averages on a less-than-daily schedule. Hourly values can sometimes be used to represent a significant source by selecting hours when the monitor was downwind of that source. Daily values, however, usually represent a varying mix of wind directions, so the impact of a specific source is harder to detect.

Levels of air pollutants fluctuate from year-to-year for various reasons, including changes in human activity and differences in weather conditions. A longer term record of measurements at a monitor helps establish the expected level of variability. Special studies in which monitors operate for a few years often lack the track record needed to assess this variability and thus may have less utility in tracking the impacts of emission changes.

ARB reviews data collected as part of the routine network and evaluates air quality trends on an ongoing basis. ARB will use this data to assess, within the context of normal air quality variability, whether any unusual trends are being observed. Staff will also work with local air districts to review and evaluate data from localized monitoring networks and special studies.

The following sections describe the various types of air quality monitoring networks that are currently operating in California, data from which will be considered under the adaptive management plan.

Statewide Criteria Pollutant Monitoring Network: The statewide criteria pollutant monitoring network consists of more than 250 monitoring locations with over 700 monitors that measure O_3, PM, NO_x, sulfur dioxide (SO_x), CO, hydrogen sulfide (H_2S) and lead. Each site in the monitoring network includes a combination of one or more monitors that collect either continuous or non-continuous air quality data. As mentioned above, gaseous monitoring data for O_3, NO_x, SO_x, CO, and H_2S, are collected hourly.

Lead monitoring data and most particulate monitoring data reflects a 24-hour average which is collected on schedules ranging from daily, up to once every sixth day. A subset of particulate monitoring sites also collect hourly data. Data for pollutants that are directly emitted, such as PM, SO_x, and CO, tend to represent concentrations over a smaller area, such as a neighborhood. In contrast, data for pollutants that are formed in the atmosphere, such as O_3, generally represents larger scale regions such as a city or county.

Statewide Toxics Monitoring Network: The statewide toxics monitoring network includes 17 sites that collect 24-hour samples two or three times each month. This network collects data for cancer-causing compounds, such as benzene, 1,3 butadiene, and formaldehyde. Data for toxic metals such as arsenic, cadmium, and chromium are also collected. The toxics monitoring network is focused on major urban areas of the state and the sites are generally co-located with other criteria pollutant monitoring. As such, the toxics network represents the combined emissions of widespread and distributed sources, rather than localized emission impacts from individual sources.

Additional toxics monitoring has been conducted by some local air districts for special purposes, some short-term, and some for ongoing interests. The South Coast Air Quality Management District and the Bay Area Air Quality Management District have been especially active in this respect. These data can assist in evaluating trends in ambient air toxics as a comparison to changes observed at covered facilities.

Localized Monitoring Networks: In addition to ARB's long-term statewide ambient monitoring network, there are several source-oriented monitoring networks that are operated by local air districts. These networks are intended to manage air quality improvement efforts and to discern near source, localized air quality impacts (from refineries, ports, and industries within communities). This data can assist in evaluating trends in ambient air quality as a comparison to changes observed at covered facilities. Some selected examples of the near-source programs are:

Bay Area Refinery Monitoring Program: The Bay Area Air Quality Management District (BAAQMD) Regulation 9 requires monitoring of SO_2 and H_2S near potential major sources of either pollutant. Each of the five oil refineries as well as an associated carbon plant within the BAAQMD jurisdiction is subject to Regulation 9 as a condition of their BAAQMD operating permit. Covered facilities are required to operate a minimum of three Ground Level Monitoring (GLM) sites with instruments capable of recording pollutant concentrations in the ambient air outside of the property line of their facility.

There are twenty GLM monitoring sites surrounding the covered facilities in the Bay Area. Five of the facilities covered are located in northwest Contra Costa County and one is located in southwest Solano County. Of the twenty GLM sites, thirteen have instruments that monitor both SO_2 and H_2S, five measure H_2S only, and two measure SO_2 only. This network has been operational for the last ten to

fifteen years, though location and site conditions may have changed over this time period.

South Coast Ports Monitoring: This monitoring network, operated by the Ports of Long Beach and Los Angeles, measures air quality at the ports and nearby communities to better manage local air quality improvement efforts. Monitoring was initiated at both ports in 2006. O_3, CO, NO_x, SO_x, and PM are collected on a real-time basis. The Port of Long Beach operates two monitoring stations: one in the Inner Port area, near West Long Beach, and the second in the Outer Port area, near the breakwater. The Port of Los Angeles operates four monitoring stations, located in the Outer Harbor area at Berth 47, at the Terminal Island Treatment Plant, in the community of San Pedro, and in the community of Wilmington. The six-monitor network was developed under the Green Port Policy.

South Coast Lead Monitoring: The South Coast Air Quality Management District has collected lead data for a number of years at five sampling sites located near lead-related facilities that were established as part of the District's Rule 1420 (Emissions Standard for Lead). The purpose of Rule 1420 is to reduce lead emissions from non-vehicular sources. It applies to all facilities that use or process materials containing lead, including primary or secondary lead smelters, foundries, lead-acid battery manufacturers or recyclers, as well as facilities that produce lead-oxide, brass, and bronze. The samplers are located at or beyond the property line of the facility and comply with United State Environmental Protection Agency (U.S. EPA) siting and operating criteria. Lead samples are generally collected on a 1-in-6 day schedule, although samples are collected more frequently at sites with the highest concentrations.

Special Studies: A subset of monitoring is special studies conducted by ARB or local air districts. The information obtained from these types of studies may be helpful in establishing "initial conditions. If additional follow-up studies are undertaken (i.e., MATES III was a follow-up to MATES II), then the data collected may provide a useful input in establishing changes in conditions (depending upon the design and location of follow up studies). The following describes two of these special studies conducted by local air districts. In addition, ARB special studies, including those using mobile monitors, may provide additional sources of data.

Multiple Air Toxics Exposure Study III (MATES III): The Multiple Air Toxics Exposure Study III (MATES III) was a monitoring and evaluation study conducted in the South Coast Air Basin (Basin). The study is a follow on to previous air toxics studies in the Basin and is part of the South Coast Air Quality Management District Governing Board's Environmental Justice Initiative. The study consists of several elements, including a monitoring program, an updated emissions inventory of toxic air contaminants, and a modeling effort to characterize risk across the Basin. It focuses on the carcinogenic risk from exposure to air toxics.

A network of ten fixed sites was used to monitor toxic air contaminants once every three days for two years. The location of the sites was the same as in the previous MATES II Study to provide comparisons over time. The one exception was the addition of the West Long Beach site. In addition to the fixed sites, five additional locations were monitored for periods of several months using moveable monitoring platforms. These micro-scale sites were chosen to determine if there were gradients between communities that would not be picked up by the fixed locations. Over 30 gaseous and particulate air toxics were measured.

Community Air Risk Evaluation (CARE) Program: The CARE program was initiated in 2004 by the Bay Area Air Quality Management District to evaluate and reduce health risks associated with exposures to outdoor toxic air contaminants in the Bay Area. The program is being carried out in three phases.

The goal of Phase I was to develop an emissions inventory for year 2000 and compile demographics and health statistics in order to identify high sites and locations of sensitive populations. In Phase 1, an annual emissions inventory was developed for diesel PM, benzene, formaldehyde and other toxic air contaminants (TACs) for localized areas. Additional studies conducted to verify TAC emissions estimates and improve the Bay Area toxic inventory include a telephone survey of residential wood burning, a carbon-14 analysis to determine new versus old carbon fractions in the ambient air, a chemical mass balance (CMB) study to estimate the source contributions to various ambient PM compounds, and a CMB analysis of organic PM compounds.

The goal of Phase II was to improve the TAC inventory and begin preliminary regional (Bay Area) and local (priority communities) scale modeling to estimate significant sources of diesel PM and TACs. Using regional modeling, the CARE program identified areas within the Bay Area, where high TAC exposures of sensitive populations–youth and seniors—intersect areas with high TAC emissions and areas with high poverty levels. This analysis identified six impacted communities where special studies, grant funding, emission reduction efforts, and enforcement actions have been focused TAC emissions reduction measures are in place throughout the Bay Area but, through the Bay Area Air Quality Management District's *Mitigation Action Plan*, special attention has been given to promoting and tracking progress in the impacted areas.

The goal of Phase III is to conduct an extensive exposure assessment to identify and rank the communities as to their potential TAC exposures, and determine the types of activities that place them at highest risk. The District will also pursue additional mitigation measures and provide a metric to assess their effectiveness in reducing overall exposure.

7. Continuous Emissions Monitors (CEMs)

Many large industrial facilities have continuous emissions monitors (CEMs) installed on equipment that are sources of air pollutants. As the name implies, CEMs units continuously monitor the concentrations of pollutants in the exhaust stream of the emission source. Typically, these monitors are required by the local air district's permit to operate, or rule provisions, to ensure that the equipment does not violate the permit conditions.

Local air districts receive data from CEMs units that are in place to satisfy permit or rule requirements. ARB will work with the local air districts to determine whether CEMs data would be useful for identifying overall facility emissions and, if so, ARB will include it in the adaptive management process.

8. Criteria Pollutant and Toxic Contaminant Emissions Inventory Databases

In addition to the GHG inventories discussed above, ARB and local air districts develop inventories of criteria pollutant and toxic contaminants. These emission inventories are used in a multitude of air quality programs to understand the relative contribution of sources, to develop control strategies for State Implementation Plans, track regional progress towards air quality goals, conduct risk assessments, and support regulatory development. Inventories are calculated estimates of emissions that are released from sources into the air where they disperse. When used in combination with other sources of data, such as economic activity and trends, ambient air quality, facility permit data and more specialized air quality data or studies, inventories can be helpful in understanding potential changes and impacts on the air quality of regions and sub-regions.

As part of the State's comprehensive inventory development process, local air districts collect emission information directly from the facilities and businesses that are required to obtain an air pollution operating permit. That data includes information about the nature of the facility's processes, the location of the facility, the type of pollutants emitted and the mass of the pollutants emitted. Facilities work with their respective local air districts to determine the best methodology to estimate their emissions, and the methodologies for estimating criteria pollutant emissions may vary across districts. Local air districts report the criteria pollutant data to ARB annually. Emission inventories of toxic pollutants are developed in a similar way and are collected through the Air Toxics "Hot Spots" Program. Local air districts collect toxic inventory data and report it to ARB every four years as defined by California statute.

It is important to note that inventories in general represent calculated estimates of emissions, except where facilities are required to use CEMs to measure emissions from stacks. For the most part, facilities (and broader source categories) rely on average emission factors and estimates of activity to determine the total estimated emissions. For these reasons, inventories are most useful for understanding relative contributions

and long term trends, inventories are not generally designed to detect day-by-day or even month-by-month changes.

In addition, many external factors can influence the variability in emissions, and it is essential to take these factors into account when looking at emission trends. For example, a facility's emissions can vary because of changes in facility-specific product demand, fuel cost or availability, cost or availability of electric power, economic conditions; labor availability; production material availability; routine maintenance; or unusual events such as power outages or breakdowns. In recent years, the economic downturn has had a dramatic impact on activity resulting in lower emissions. As the economy recovers, a commensurate increase in emissions should be expected. Another factor that has to be considered when comparing inventories is the improvement in methods used for estimating emissions. Over time, our understanding of emission rates and activity from sources has improved substantially. With new methods, the resulting emission estimate may be different. Therefore, a change in emissions at a facility from year-to-year may be the result of a better characterization of emissions rather than a real world increase or decrease. The following sections describe some of the available emission inventory data and databases maintained by ARB. Local air districts also maintain data on their facilities; two of these are also described.

a. California Emission Inventory Development and Reporting System (CEIDARS)

The federal Clean Air Act requires states to compile emission inventories of criteria pollutants. California's statewide emissions inventory is maintained by ARB, and is populated with data submitted by the local air districts, as well as that collected by ARB. The criteria pollutant emission inventory includes information on the emissions of reactive organic gases (ROG), NO_x, SO_x, CO, and PM. Data are gathered on an ongoing basis and stored in CEIDARS. A summary of the criteria pollutant inventory is published in ARB's Air Quality and Emissions Almanac. More information on CEIDARS and the Almanac can be found at:

http://www.arb.ca.gov/ei/general.htm

http://www.arb.ca.gov/aqd/almanac/almanac.htm

CEIDARS contains California's comprehensive inventory and includes information on approximately 13,000 individual facilities such as electric power plants and refineries. There are also about 135 aggregated point source categories. Aggregated point sources are not inventoried as individual facilities but are estimated as a group and reported as a single source category (e.g., gas stations and dry cleaners). In addition to individual facilities, CEIDARS includes approximately 80 source categories made up of sources of pollution, such as architectural coatings and consumer products, spread across a region and mobile sources - all on-road vehicles such as automobiles and trucks; plus off-road vehicles such as trains, ships, aircraft; and farm equipment.

Emission estimates within CEIDARS are based on a snap-shot of a variety of dynamic and variable processes. The data in CEIDARS represent annual average estimates for a specific calendar year. Annual average emissions are stored for each county, air basin, and district. There is also a Facility Search Tool that provides direct access to the year-by-year emissions reported for individual facilities, both criteria and toxics:

http://www.arb.ca.gov/app/emsinv/facinfo/facinfo.php

CEIDARS data can be used to look at trends in emissions as a comparison to observed changes at covered sources.

b. California Toxic Inventory (CTI)

ARB collects toxic emissions from thousands of facilities in California. The CTI provides annual average estimates of toxic emissions and is updated every four years. CTI data is stored in CEIDARS (described above).

Toxic pollutant emissions from stationary sources include point source data provided by local air districts pursuant to the Air Toxics "Hot Spots" Program (AB 2588). The Air Toxics "Hot Spots" Information and Assessment Act (AB 2588, 1987, Connelly) was enacted in 1987, and requires stationary sources to report the types and quantities of certain substances routinely released into the air. The goals of the Air Toxics "Hot Spots" Act are to collect emission data, to identify facilities having localized impacts, to ascertain health risks, to notify nearby residents of significant risks, and to reduce those significant risks to acceptable levels.

For sources without AB 2588 data, the CTI is developed by dis-aggregating (also known as "speciating") CEIDARS-based estimates of total organic gas (TOG) and PM for area, mobile, and natural sources using the most recent speciation profiles. Speciation profiles provide species-specific mass ratios (i.e., chemical-species-to-total TOG or PM) and are based on source tests from representative emission sources. The "speciated" emissions for each source category are then reconciled with reported stationary point source toxics data to establish a complete inventory. More information on the CTI can be found at:

http://www.arb.ca.gov/toxics/cti/cti.htm

CTI data can be used to evaluate trends in emissions of air toxics as a comparison to observed changes at covered sources.

c. Data for Non-vehicular Source, Consumer Products and Architectural Coatings Fees

The Health and Safety Code authorizes ARB to impose additional fees on non-vehicular sources (facilities) that emit 250 tons or more per year of any nonattainment pollutant or its precursors. While the data used for the fee program

initially comes from ARB CEIDARS database, ARB provides the facilities and the local air districts an opportunity to update and correct emission estimates. These updates are more current than the annual criteria pollutant submittals. The fee program includes approximately 60 facilities. These fees are used by ARB to mitigate or reduce air pollution created by non-vehicular sources in the State.

http://www.arb.ca.gov/ei/nscpac_fees/nscpac_fees.htm

This data provides another source of emission data that can be compared to observed changes at covered emission sources.

d. South Coast AQMD Annual Emission Reporting (AER) Program

The South Coast Air Quality Management District's Annual Emission Reporting (AER) program was developed to track emissions of air contaminants from permitted facilities. The data collected by AER is used to update the comprehensive emissions inventory for the District, which includes Orange County, the non-desert portions of Los Angeles and San Bernardino counties, and the Riverside county areas west of the Palo Verde Valley. Fees for emissions of air contaminants are assessed based on the reported data. These fees help to cover the costs of evaluating, planning, inspecting, and monitoring air quality efforts. Under this program, those who emit more, pay more toward air pollution control efforts – and at the same time are given an incentive to reduce emissions. On January 1, 2008, the South Coast Air Quality Management District moved AER from a fiscal year basis (July 1 through June 30 of the following year) to a calendar year basis (January 1 through December 31 of each year). The compiled inventory is published in each update of the Air Quality Management Plan. More on the AER can be found at:

http://www.aqmd.gov/aer/aer.html

e. South Coast AQMD RECLAIM Program

The REgional CLean Air Incentives Market (RECLAIM) program is a cap-and-trade program operated by the South Coast Air Quality Management District. It encompasses most of the Basin's largest NO_x and SO_x stationary sources. It was developed to make significant progress in cleaning up the worst air in the nation. It is a multi-industry program with each facility having annual allocations and declining balances. Developed in the early 1990s, RECLAIM was seen as an innovation compared to previous command-and-control programs. Benefits included lower costs and greater flexibility for industry participants, and secured emission reductions with better emissions monitoring for environmental and community interests. More information on RECLAIM can be found at:

http://www.aqmd.gov/reclaim/index.htm

Nearly 80 percent of emissions under RECLAIM are from major sources, which are monitored by CEMs. Therefore, the accuracy of these emission data is of utmost importance in determining if RECLAIM is achieving its emission goals. In order to assure the highest accuracy, several checks are imposed on CEMs – initial certification and re-certification when modified, daily calibration checks, routine quality assurance and quality checks (QA/QC), and a semi-annual relative accuracy test audit (RATA).

B. Forest Data

ARB identified data sources for the evaluation of potential forest impacts caused by the U.S. Forest Protocol. Some of the data sources described below are readily available and some are expected to be available at a later date. ARB expects that it will be able to review and analyze some of the data sets without expert assistance. Other data sets require ARB to work with other State agencies and academia, as well as out-of-state resource agencies to interpret the data, and to conduct further analysis using the data.

In 2012, ARB plans to hire a contractor to develop a process to track data to detect environmental changes resulting from the U.S. Forest Protocol. ARB will also coordinate with and utilize the forestry expertise of the resource agencies during the implementation of this adaptive management plan. By working with these forestry experts and stakeholders, ARB can best ensure that the robustness of the adaptive management approach for the U.S. Forest Protocol is equal to that of the adaptive management approach for local air quality. Details as to how the data will be used will be developed through the work of the ARB contractor and the expertise of the resource agencies. That process is further described in the Review and Analysis section of this plan.

1. U.S. Forest Protocol Project Data

The proposed Regulation requires reporting of information on the performance of the forest offset projects prior to the issuance of compliance offset credits. Data reported under the U.S. Forest Protocol includes summarized forest project monitoring data, an annual update of the project's forest carbon inventory that calculates the amount of GHG reductions and carbon sequestration. This information will be in the offset project data annual report.

ARB will collect U.S. Forest Protocol data for each individual forest project. This information will be submitted annually by the project developer to ARB through the annual report. Forest project developers will assemble the annual report, and then submit it for verification to ARB or an accredited registry, and it must be verified by an ARB-accredited third party offset project verifier. ARB will not obtain this forest project level data until the first annual report is submitted during the first reporting cycle in 2013.

Based on the project type, the annual report will contain the following forest project information where applicable:

- Forest project name, location, type of project and project operator.
- Reporting period.
- Ownership, including any changes in ownership.
- Statement of compliance with all applicable laws and regulations.
- Estimated carbon stocks in all required carbon pools.
- Explanation of any decrease over a 10-year consecutive period in the standing live carbon pool.
- Description of how the project meets the definition of natural forest management.
- Projections of baseline and actual harvesting volumes from the forest project area over a 100 year period.
- Estimate of harvest volumes and associated carbon in harvested wood products.
- Estimate of mill efficiency.
- Baseline carbon estimates for all carbon pools.
- Uncertainty discount for avoided conversion projects.
- Forest carbon inventory (updated annually) following all required protocol calculation methodologies and models.
- Calculation of carbon sequestration and GHG reductions.
- Calculation of GHG removal enhancements.
- Description and explanation of the unintentional "reversal."[2]
- Reversal risk rating.
- Calculation of Forest Buffer Account contribution.

This information will be useful to get a better understanding of each forest project. Each forest project is unique and may not have the same ecosystem characteristics to make comparisons amongst forest projects. Using the annual report data, ARB will work with the ARB contractor to implement a specific process to review the data sources and track data to assess potential forest impacts.

2. Forest Buffer Account Information

Due to the possibility that forest projects could unintentionally "reverse" their carbon storage because of wildfire, pest infestation, or disease, negating the benefits of those projects, ARB will create and maintain a Forest Buffer Account holding a percentage of ARB-issued compliance offset credits from forest offset projects. ARB will annually monitor the number of compliance offset credits in the Forest Buffer Account as it relates to the number of reported reversals.

The Forest Buffer Account is a mechanism to replace offset credits in the event of an unintentional reversal, thereby insuring that GHG reductions reflected in offset credits

[2] "Reversal" refers to an event that abruptly releases stored carbon, such as a high intensity wildfire.

are permanent. A portion of the offset credits issued to forest projects must be placed into the Forest Buffer Account to cover unintentional reversals.

3. Greenhouse Gas Mandatory Reporting Regulation (MRR)

In addition to the reporting of GHG emissions from fossil fuel combustion, the MRR also requires reporting of CO_2 emissions from biomass derived fuels, including forest biomass. As part of the recent proposed modifications to the MRR, ARB addressed stakeholder concerns related to potential increased use of forest-derived wood and wood waste. In the MRR, end users of solid biomass fuels would report the mass of fuel consumed by fuel type, and end users of forest biomass would also report location of forest biomass used.

4. ARB's Updated GHG Statewide Inventory for Forests

ARB is responsible for developing and maintaining California's statewide GHG emission inventory, which includes a sector on GHG emissions and atmospheric sequestration of CO_2 from forests and rangelands. ARB is working with U.C. Berkeley to develop a next-generation GHG inventory system for forests, rangeland, and other wildlands statewide. The contractor will develop procedures to use in combination with ground-based biometric data from the U.S. Department of Agriculture - Forest Service Forest Inventory and Analysis plots, satellite remote sensing data, and other data on disturbance processes (fire, harvest, land use conversion, etc.). This data will be used to develop estimates of CO_2 uptake and GHG emissions across the landscape statewide (at appropriate spatial and temporal scales).

5. California Forest Practices Act as Administered by CalFire

The California Forest Practices Act provides a CEQA functional equivalent process for reviewing and permitting timber harvests. This process evaluates project-level and cumulative impacts (usually at a planning watershed scale) to ensure that all impacts are mitigated to a level less than significant. Impacts to State and federally listed and non-listed species and their habitats, and water resources (e.g., watercourses, lakes, marshes, meadows and wet areas; water supply; watersheds; riparian areas) are considered, as well as soils, archaeological resources, and hazards from wildfire, insects and disease. The California Department of Forestry and Fire Protection (CalFire) inspects projects to evaluate compliance with prescribed mitigations and timber restocking, and corrective action is taken if necessary to ensure satisfactory project completion. Large landowners must develop long-term landscape-level management plans and provide regular reporting to CalFire on compliance with projected levels of timber harvesting. Some landowners also conduct ongoing surveys or monitoring of habitat or water quality at the request of other state agencies.

6. Timber Yield Tax and Harvest Values Schedules

The California State Board of Equalization has a Timber Yield Tax program that sets harvest values of timber and collects an in lieu tax when it is harvested. This data is aggregated by county and provides forest land ownership and timber harvest volumes.

7. Fire and Resource Assessment Program (FRAP)

CalFire implements the FRAP program that conducts periodic assessments of California's forests and rangelands. The forest and range assessment report includes a detailed assessment of ecosystem characteristics within California's forests.

For the 2010 assessment, FRAP's analytical framework is based on defining assets and threats specific to each subtheme. Geographic information systems (GIS) technology is used to combine or "overlay" assets and threats, to determine areas of both high value and high threat. These priority landscapes rank areas for where action is needed in terms of applying various tools that can result in the desired future landscape condition. The 2010 Assessment will also take into consideration various existing planning efforts, ranging from statewide plans (i.e., California's Wildlife Action Plan) to Community Wildfire Protection Plans. The final Assessment product will combine qualitative, quantitative, and geospatial data.

8. Geographic Information System (GIS) and Geodatabases

Several GIS databases are available that report activities and processes occurring on federal, State, and private forest lands in California. These include activities such as timber operations (i.e., road building, thinning, harvest, replanting) and non-timber related activities (i.e., prescribed burning, salvage logging in areas hit by wildfire, replanting, and treatment for disease/pest infestations). Fires of all categories are also carefully mapped using GIS.

<u>CalFire - Forest Practice GIS</u>
CalFire's Forest Practice GIS captures current and historic timber harvesting activities for over 4 million acres of California timberland. These data layers include silviculture, yarding, new road construction, watercourse classifications, and timberland conversions, which are tracked through GIS. Once in GIS, this information can be graphically represented on maps and is available for the analyses of local and regional cumulative impact assessments, and to meet the requirements of California's Forest Practice Rules.

Available geodatabases and GIS data layers include: Timber Harvesting Plans from 2000 to 2010; non-industrial timber management plans from 1991 to 2010; and notice of timber operations from 1991 to 2009.

U.S. Forest Service, Region 5 - GIS Clearinghouse
The U.S. Forest Service clearinghouse developed a geodatabase that maps activities (i.e. harvest, thinning, vegetation fuels management, reforestation) accomplished on national forest lands in California for the approximate period of October 2003 to December 2010.

9. Special Monitoring Projects (CalFire, Department of Fish and Game, Regional Water Quality Control Boards)

CalFire conducts a statewide monitoring program that analyzes the effectiveness of timber harvest rules and best management practices to protect water quality and also participates in cooperative instream monitoring programs in various parts of the State. Other studies are conducted by responsible State and federal agencies, including the Department of Fish and Game, Department of Conservation's California Geological Survey (previously known as the Division of Mines and Geology), and the Regional Water Quality Control Boards, the U.S. Fish and Wildlife Service and the National Marine Fisheries Service.

V. Review and Analysis

ARB will take a stepwise approach to evaluating the data gathered as part of the adaptive management plan. In doing this, ARB will first evaluate data that will provide a forward look at potential emissions increases or forest impacts and is readily available to identify potential impacts at the earliest opportunity. The indicators that ARB investigates will be prioritized, or "tiered" based on the order in which they will be used to assess if unanticipated adverse impacts have occurred as a result of the Regulation or U.S. Forest Protocol. First tier indicators would indicate a potential environmental change. Second tier indicators would indicate if an environmental change was caused by the Regulation or U.S. Forest Protocol. Third tier indicators would indicate if an environmental change caused by the Regulation or U.S. Forest Protocol caused an adverse impact.

If the weight of evidence indicates that the answer to any of the following questions is "yes", then the evaluation moves to the next tier, ultimately culminating in the appropriate response to the adverse impact if all questions are answered in the affirmative. Staff will prioritize the order of investigations to answer the following questions:

1. Has an environmental change taken place?
   If yes, then;
2. Is the environmental change caused by the Regulation or U.S. Forest Protocol?
   If yes, then;
3. Has a change that is determined to be caused by the Regulation or U.S. Forest Protocol caused an adverse impact?
   If yes, then;
4. Identify the options for responding and take appropriate action.

Different indicators will be used to assess the answer to these questions. The weight of evidence available from this approach will guide ARB's conclusions on whether or not the cap-and-trade regulation was the cause of a potential adverse impact.

A. Local Air Quality Impacts

Tier 1 Indicators:
Tier 1 indicators will be used to assess if a change in operation or project development has taken place that could be caused by the Regulation (determined in the Tier 2 analysis) and could result in adverse localized air quality impacts (determined in the Tier 3 analysis). If there is a positive result in screening Tier 1 indicators, ARB will initiate the next step to investigate whether the change was caused by the Regulation. Tier 1 indicators do not rely on monitoring of criteria pollutants or toxic air pollutants but do show changes in operation or project development that could result in increases in criteria pollutants or air toxics that ARB will analyze further in Tier 2 and Tier 3 (discussed below).

Indicators

- Covered facility annual GHG emissions.
- Fuel volume, or new fuel used.
- New local air district or CEC application for permit to construct or modify submitted by a facility covered by the Regulation.
- Holdings of compliance instruments.

Example Analyses

The types of analyses that draw on Tier 1 indicators may include:

- Identify covered facilities reporting an increase in annual GHG emissions through MRR.
- Identify covered facilities reporting increased fuel volume used or a new fuel used as reported through the MRR (e.g., biomass or tires).
- Identify covered facilities reporting new equipment through the MRR; investigate use of equipment and if emissions increased due to new equipment.
- Identify covered facilities that have applied for new permits for construction or modification; investigate if the project is likely to increase localized emissions and the primary driver for the new facility or modifications (cap-and-trade regulation, efficiency, etc.).
- Identify covered facilities that are holding compliance offset credits above the amount they are expected to need for compliance.
- Identify facilities or geographic regions that show GHG emissions increases greater than expected from average economic growth.
- Identify regions in the State where facilities are located and areas where multiple facility emissions could contribute to localized air quality impacts.

No single Tier 1 indicator alone would necessarily reflect that an impact caused by the Regulation has occurred. They would only reflect that there has been, or potentially could be, an environmental change. Additional investigation would be necessary if significant change is observed in one indicator or if a variety of Tier 1 indicators reflect environmental changes.

Tier 2 Indicators:
If the analysis of Tier 1 indicators indicates that there has been an environmental change, then ARB will investigate the Tier 2 indicators to assess if the environmental change was caused by the Regulation. A positive result in screening will cause initiation of the next step.

It is likely that determining the cause of a change will require the use of multiple Tier 2 indicators. Additionally, it is highly probable that most changes will have multiple causes (e.g., growing economies, changes in world-wide manufacturing trends, etc.). Potential causes identified at this time are:

- Economic growth related to recovery from the recent recession.
- Global manufacturing trends and availability of new technology.
- Changes in a company's business model.
- Dry rainfall year leading to decrease in hydroelectric power production.
- Impacts of other regulatory programs (i.e., Renewable Portfolio Standard, reduction of once-through-cooling practices for electricity generation, federal or local regulations, etc.).
- Changes in emission factors or other methodologies used to report or calculate emissions.
- Cap-and-trade regulation.

Indicators

- Forecasted economic growth.
- Facility-specific product demand.
- Consumer demand.
- Meteorological conditions (e.g., rainfall or ambient temperature).

Example Analyses

The types of analyses that draw on Tier 2 indicator data may include:

- Assess if changes in emissions are comparable to changes in the economy or consumer demand.
- Assess if manufacturing trends or changes in common business models have occurred that may result in activities that increase emissions.
- Assess if hydroelectric power production has decreased and if fossil fuel energy production increased as a result.

- Assess if there have been any regulatory or policy changes that impacted emissions.
- Monitor industry-specific trade data to assist in determining whether/where potential changes may occur.
- Assess methodology changes in how emissions are reported or calculated.

Tier 3 Indicators:
If an environmental change is attributed to the Regulation, ARB will review Tier 3 indicators to assess if the change has had an adverse impact. An increase in NO_x at a facility with a 100 foot tall exhaust stack may have no discernable impact on the local community if the design allows emissions to disperse. However, increased toxic air pollutant emissions monitored at a facility's fence line may indicate an adverse impact. As with Tier 2 indicators, it is likely that investigation of multiple indicators will be required to assess if an adverse impact to localized air quality has occurred.

Indicators

- Criteria and toxic pollutant emissions.
- Changes in ambient air quality monitoring data:
  - Criteria pollutants;
  - Toxic air pollutants; and
  - Localized monitoring networks.
- Emissions measured in facility CEMs data.
- Emissions determined in California Clean Air Act Fee Program data.

Example Analyses

The types of analyses that draw on Tier 3 indicators data may include:

- Identify covered facilities reporting an increase in facility annual emissions (criteria pollutants or toxic air pollutants) through review of local air district emission surveys, special purpose monitoring, or CEMs data; investigate reason for emissions increase.
- Identify criteria pollutant or toxic air pollutant monitoring network data indicating increased ambient concentrations; investigate reason that monitored ambient concentrations increased.
- Compare activity reported through the criteria pollutant inventory or specialized inventories supporting programs such as RECLAIM.

B. Forest Impacts

The environmental impacts analysis in the FED concluded that increased forest project related impacts attributable to the Regulation, or the U.S. Forest Protocol are unlikely based on available data and current laws that regulate forest activities. However, ARB could not determine that increases would not ever occur. ARB, therefore, committed to use an adaptive management approach as an integral part of the cap-and-trade

program to evaluate data for potential unanticipated impacts that could be caused by the Regulation, or the U.S. Forest Protocol.

ARB will use the same approach to evaluate forest impacts as is being used for local air quality impacts. Under this proposed adaptive management plan, in 2012, ARB will hire a contractor to develop and implement a specific process to track data to detect environmental changes resulting from the U.S. Forest Protocol. ARB will also coordinate with and utilize the forestry expertise of the resource agencies during the implementation of this adaptive management plan. By working with these forestry experts, ARB can best ensure that the robustness of the adaptive management approach for the U.S. Forest Protocol is equal to that of the adaptive management approach for local air quality. Details as to how the data will be used will be developed through the work of the ARB contractor and the expertise of the resource agencies.

The ARB contractor will develop Tier 1, Tier 2, and Tier 3 indicators and analyses. The ARB contractor will conduct the review and analysis under ARB's direction and the results will be incorporated into the annual adaptive management reports. Additionally, the ARB contractor will be called upon to review the usefulness of the data sources, including screening forest offset project annual report data. ARB will work with the ARB contractor to assess if any relevant data sets are missing from the list set forth in the previous section, as well as investigate the effectiveness of the existing data sources. Additionally, the ARB contractor will educate staff in general forest practices, indicators of potential forest impacts, and forest assessments and analyses.

C. Causation

In conducting the analysis, it will be necessary to consider normal variations, existing trends, and other factors that may be responsible for changes in the data. For example, air quality data can vary significantly from year-to-year because of meteorology. Additionally, changes in economic activity can produce large impacts on air quality and emissions trends, and factors such as rainfall can have significant impacts on emissions as a result of California's utilization of hydroelectric power as a source of energy.

ARB recognizes that the results of the data review are unlikely to point absolutely to the cap-and-trade regulation or U.S. Forest Protocol as the cause of a potential adverse impact, and that a judgment will need to be made based on the weight of evidence available. It is likely that it will be necessary for ARB to use several sources of data in combination to conclude that an adverse impact is attributable to the Regulation or U.S. Forest Protocol.

1. Localized Air Quality

If initial screening and analysis of the data point to a potential impact, then ARB will take steps to assess why the change occurred. An example scenario that would indicate a change to be further investigated is as follows: a new application is received by a local air district for a permit to construct or modify a cogeneration unit at a facility. For this

case, ARB would work with the local air district to obtain the details of the project and the environmental analysis. If the project is likely to increase emissions, then ARB would consult with the local air district on the impact of the new unit on overall facility emissions. If the weight of the evidence were to indicate that the cogeneration facility is 1) being proposed as a result, directly or indirectly, of the cap-and-trade regulation; and 2) would increase localized emissions and result in an adverse impact to public health, then the adaptive management plan would require ARB to move to the next step – devising and implementing a response.

2. Forest Impacts

As with potential local air quality impacts, if initial screening and analysis of the data point to a potential impact then ARB will take steps to assess the cause of the change. ARB will work with forestry experts to refine the details of the screening and analysis process to ensure that the robustness of the adaptive management approach for the U.S. Forest Protocol is equal to that of the adaptive management approach for local air quality. The areas to refine are: (1) data and data source identification (information gathering) and (2) analysis to determine whether an adverse impact is caused by the U.S. Forest Protocol (review and analysis).

VI. Response

If the process described above confirms that there has been an adverse impact to local air quality or a forest impact caused by the cap-and-trade regulation or U.S. Forest Protocol, under the adaptive management plan, ARB is committed to developing and implementing appropriate responses through a public process, including consideration and approval by the Board as necessary. ARB would work to ensure that the level of response is commensurate with the level of the impact.

ARB would consider a range of options to address localized adverse air quality impacts. These could include the adoption of additional regulatory requirements, using funds obtained from the sale of allowances to support local mitigation projects, coordination with other agencies to provide additional incentives for energy efficiency or other emission reduction activities within the community, or modifications to the Regulation.

For unanticipated impacts from the U.S. Forest Protocol, ARB could consider revising the types and/or geographic location of forest offset projects, or disallowing the use of certain types of U.S. Forest Protocol compliance offset credits. Other types of responses are also possible and would be considered and implemented as necessary.

The examples are illustrative and not intended to be an exhaustive list of appropriate responses. What responses may be appropriate depends on what impacts are identified, the specific causes of those impacts, and the responses available at some future point in time (which may be different than the responses available today). These considerations support the use of adaptive management, which will allow ARB to devise the most appropriate response should unintended consequences occur. While it is not

feasible in this plan to identify all possible future responses, it is clear that ARB has many tools available to it should unanticipated consequences occur.
This plan requires that where adverse impacts related to localized air quality or to forestry occur, ARB must take appropriate action. In most cases, this will require staff to identify potential responses and promptly take a recommended response to the Board for approval.

VII. Public Process for this Adaptive Management Plan

As mentioned earlier, the Board will consider this plan at the October 20-21, 2011, Board meeting. Upon Board approval, ARB will work with stakeholders, local air districts, and resource agencies to finalize specific details of data gathering.

An important part of the public process is reporting. The first adaptive management report is planned for December 2012, and will focus on the first phase of implementation. Annually thereafter, staff will provide reports to the public and the Board on the implementation of the adaptive management plan. The annual adaptive management plan reports will, among other things, outline the data collected and the trends observed, and discuss any recommended responses.

The plan would be implemented based on the following schedule:

October 10, 2011	ARB releases Draft Adaptive Management Plan for comment.
October 20-21, 2011	Board considers Adaptive Management Plan for approval.
November 2011	Staff works with local air districts, resource agencies, and stakeholders to finalize specific details concerning data gathering under the Adaptive Management Plan.
Early 2012	ARB contracts for third-party forestry expertise.
Mid-2012	Staff updates Board on Adaptive Management Plan implementation.
December 2012	Staff releases Adaptive Management Implementation Report (prior to first compliance period).
December 2013	Staff updates Board on Adaptive Management implementation.
December 2014	Staff releases Adaptive Management Report for calendar year 2013.

December 2015	Staff releases Adaptive Management Report for calendar year 2014 and end of first compliance period.
Ongoing	Staff releases Adaptive Management Report annually.

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October 2011

Subchapter 10 Climate Change, Article 5, Sections 95800 to 96023, Title 17, California Code of Regulations, to read as follows:

Article 5: CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS

Note: All text is new.

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Subarticle 2: Purpose and Definitions

§ 95801. Purpose.

The purpose of this article is to reduce emissions of greenhouse gases associated with entities identified in this article through the establishment, administration, and enforcement of the California Greenhouse Gas Cap-and-Trade Program by applying an aggregate greenhouse gas allowance budget on covered entities and providing a trading mechanism for compliance instruments.

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.

§ 95802. Definitions.

(a) Definitions. For the purposes of this article, the following definitions shall apply:

(1) "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.

(2) "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.

(3) "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.

(4) "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)).

(5) "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.

(6) "Agent" in a beneficial holdings relationship pursuant to 95834 means the registered entity acquiring and holding compliance instruments to be transferred to another entity under an agreement disclosed to ARB.

(7) "Air Dried Ton of Paper" means paper with 6 percent moisture content.

(8) "Allowance" means a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(9) "Alternate Authorized Account Representative" means the single entity identified during the account application process who may act on behalf of the authorized account representative.

(10) "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℉, where API refers to the American Petroleum Institute.

(12) "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.

(13) "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) "Asset Controlling Supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number and specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California. Bonneville Power Administration (BPA) is recognized by ARB as an asset controlling supplier.

(15) "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) "Associated Gas" or "Produced Gas" means a natural gas that is produced from gas wells or gas produced in association with the production of crude oil.

(17) "Auction" means the process of selling California Greenhouse Gas Allowances by offering them up for bid, taking bids, and then distributing the allowances to winning bidders.

(18) "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) "Auction Reserve Price" means a price for allowances below which bids at auction would not be accepted.

(20) "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) "Authorized Account Representative" means an entity approved through the application process outlined in 95832 and legally bind each entity that owns compliance instruments held in the account in all matters pertaining to this article.

(22) "Authorized Project Designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

(23) "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).

(24) "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.

(25) "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.

(26) "Banking" means the holding of compliance instruments from one compliance period for the purpose of sale or surrender in a future compliance period.

(27) "Barrel of Oil Equivalent," with respect to reporting of oil and gas production, means barrels of crude oil produced, plus associated gas produced converted to barrels at 5.8 MMbtu per barrel.

(28) "Beneficial Holding" means the acquisition and holding of compliance instruments by a registered entity to be transferred to another registered entity under an agreement disclosed to ARB.

(29) "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.

(30) "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.

(31) "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.

(32) "Biomass-Derived Fuels" or "Biomass Fuels" or "Biofuels" means fuels derived from biomass.

(33) "Biomethane" means biogas that meets pipeline quality natural gas standards.

(34) "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.

(35) "Budget Year" means the annual allowance budget assigned pursuant to subarticle 6.

(36) "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.

(37) "Calcium Ammonium Nitrate Solution" means calcium nitrate that contains ammonium nitrate and water. Calcium ammonium nitrate solution is generally used as agricultural fertilizer.

(38) "Calendar Year" means the time period from January 1 through December 31.

(39) "California Balancing Authority" shall have the same meaning ascribed in section 95102(a) of MRR.

(40) "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.

(41) "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.

(42) "Cap" means the total number of California GHG Allowances that the Executive Officer issues over a given period of time.

(43) "Cap-and-Trade Program" means the requirements of this article.

(44) "Carbon Dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(45) "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).

(46) "Carbon Stock" means the quantity of carbon contained in an identified GHG reservoir.

(47) "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.

(48) "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.

(49) "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.

(50) "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.

(51) "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.

(52) "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.

(53) "Combustion Emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(54) "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.

(55) "Compliance Instrument" means an allowance, ARB offset credit 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.

(56) "Compliance Obligation" means the quantity of verified reported emissions or assigned emissions for which an entity must submit compliance instruments to ARB.

(57) "Compliance Offset Protocol" means an offset protocol adopted by the Board.

(58) "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.

(59) "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.

(60) "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.

(61) "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.

(62) "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.

(63) "Counterparty" means the opposite party in a bilateral agreement, contract, or transaction.

(64) "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 2008 or any subsequent year more than the applicable threshold level specified in section 95812 (a) of this rule.

(65) "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.

(66) "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.

(67) "Data Year" means the calendar year in which emissions occurred.

(68) "Deforestation" means direct human-induced conversion of forested land to non-forested land.

(69) "Delivered Electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

(70) "Diesel Fuel" means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and non-taxed fuels.

(71) "Direct Delivery of Electricity" or "directly delivered" has the same meaning as ascribed to MRR section 95102(a).

(72) "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.

(73) "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.

(74) "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).

(75) "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).

(76) "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.

(77) "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).

(78) "Dolime" is calcined dolomite.

(79) "Dry Gas" means a natural gas that is produced from gas wells not associated with the production of crude oil.

(80) "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).

(81) "Early Action Offset Program" means a program that meets the requirements of section 95990(a) and is approved by ARB.

(82) "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.

(83) "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.

(84) "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.

(85) "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.

(86) "Electricity Generating Facility" means a facility that generates electricity and includes one or more generating units at the same location.

(87) "Electricity Importers" are marketers and retail providers that deliver imported electricity. For electricity delivered between balancing authority areas, 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, 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).

(88) "Eligible Renewable Energy Resource" has the same meaning as defined in Section 399.12 of the Public Utilities Code.

(89) "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.

(90) "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.

(91) "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.

(92) "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.

(93) "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.

(94) "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.

(95) "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.

(96) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(97) "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.

(98) "Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

(99) "Exported Electricity" shall have the same meaning ascribed in section 95102(a) of MRR.

(100) "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.

(101) "Facility" 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.

(102) "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.

(103) "First Deliverer of Electricity" or "First Deliverer" means the operator of an electricity generating facility in California or an electricity importer.

(104) "Flash Point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

(105) "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) "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) "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) "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) "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) "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) "Fractionates" means the process of separating natural gas liquids into their constituent liquid products.

(112) "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) "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) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas, or a supplier of liquid petroleum gas as specified in MRR.

(115) "Fugitive Emissions" means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(116) "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) "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) "Gaseous Hydrogen" means hydrogen in a gaseous state.

(119) "Geologic Sequestration" means the process of injecting CO_2 captured from an emissions source into deep subsurface rock formations for long-term storage.

(120) "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.

(121) "Greenhouse Gas" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

(122) "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) "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) "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) "Greenhouse Gas Removal Enhancement" or "GHG Removal Enhancement" means a calculated increase in GHG removals relative to a project baseline.

(126) "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) "Greenhouse Gas Sink" or "GHG Sink" means a physical unit or process that removes a GHG from the atmosphere.

(128) "HD-5" or "Special Duty Propane" has the same meaning as contained in MRR.

(129) "HD-10" has the same meaning as contained in MRR.

(130) "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) "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 registered into the California cap-and-trade program or an account under the control of the Executive Officer.

(132) "Horsepower Tested" means the total horsepower of all turbine and generator set units tested prior to sale.

(133) "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) "Hydrocarbon" means a chemical compound containing predominantly carbon and hydrogen.

(135) "Hydrofluorocarbon" or "HFC" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

(136) "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) "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.

(138) "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) "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.

(140) "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.

(141) "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.

(142) "Inventory Position" means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(143) "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) "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) "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) "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 ℉ at the 10 percent recovery point and a final maximum boiling point of 572 ℉. Included are Jet A, Jet A–1, JP–5, and JP–8.

(147) "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) "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).

(149) "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) "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) "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) "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) "Liquefied Hydrogen" means hydrogen in a liquid state.

(154) "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.

(155) "Listed Industrial Sector" means covered industrial sectors that are eligible for industry assistance specified in Table 8-1 of subarticle 8.

(156) "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) "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) "Market Index" means any published index of quantities or prices based on results of market transactions.

(159) "Marketer" means a purchasing-selling entity that delivers electricity and is not a retail provider.

(160) "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.

(161) "Methane" or "CH_4" means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(162) "Metric Ton" or "MT" means a common international measurement for mass, equivalent to 2,204.6 pounds or 1.1 short tons.

(163) "Mixed Crude Oil" means a mix of both heavy and light crude oil.

(164) "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) "Motor Gasoline (finished)" has the same definition as MRR.

(166) "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) "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) "Natural Gas" means a naturally occurring mixture 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) "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. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus.

Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(170) "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) "Nitric Acid" means HNO_3 of 100% purity.

(172) "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.

(173) "Notice of Delegation" means a formal notice used to delegate authority to make an electronic submission to the accounts administrator.

(174) "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 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) "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) "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) "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) "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) "Offset Project Operator" means the entity(ies) with legal authority to implement the offset project.

(180) "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) "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) "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) "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) "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) "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) "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) "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) "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.

(189) "Oxidation" means a reaction in which the atoms in an element lose electrons and the valence of the element is correspondingly increased.

(190) "Ozone Depleting Substances" or "ODS" means a compound that contributes to stratospheric ozone depletion.

(191) "Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

(192) "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) "Permanent Retirement Registry" means the publicly available registry in which the Executive Officer will record the serial numbers of the retired compliance instruments.

(194) "Petroleum" means oil removed from the earth and the oil derived from tar sands, and/or shale.

(195) "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) "Pickled Steel Sheet" means hot rolled steel sheet that is sent through a series of hydrochloric acid baths that remove the oxides.

(197) "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.

(198) "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) "Plasterboard" is a panel made of gypsum plaster pressed between two thick sheets of paper.

(200) "Point of Delivery" 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) "Point of Receipt" 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) "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) "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.

(204) "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 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.

(205) "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 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.

(206) "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.

(207) "Power" means electricity, except where the context makes clear that another meaning is intended.

(208) "Primary Refinery Products" means aviation gasoline, motor gasoline, 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.

(209) "Principal" means the registered entity in a beneficial holding relationship to which compliance instruments will be transferred by an agent under an agreement with the principal that is disclosed to ARB.

(210) "Proceeds" means monies generated as a result of an auction or from sales from the Allowance Price Containment Reserve.

(211) "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.

(212) "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.

(213) "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.

(214) "Producer" means a person who owns leases, operates, controls, or supervises a California production facility.

(215) "Product Data Verification Statement" means the final statement rendered by a verification body attesting whether a reporting entity's product data in their 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.

(216) "Professional Judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

(217) "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.

(218) "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.

(219) "Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

(220) "Property Right" means any type of right to specific property whether it is personal or real property, tangible or intangible.

(221) "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.

(222) "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.

(223) "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.

(224) "Purchasing-Selling Entity" or "PSE" means the same meaning as ascribed in MRR.

(225) "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 electriticy 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.

(226) "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.

(227) "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 emissions data in the submitted emissions data report is free of material misstatement, but the emissions data may include one or more 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.

(228) "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 product data in the submitted emissions data report is free of material misstatement, but the product data may include one or more 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.

(229) "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.

(230) "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.

(231) "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.

(232) "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.

(233) "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.

(234) "Reasonable Assurance" means a high degree of confidence that submitted data and statements are valid.

(235) "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.

(236) "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.

(237) "Recycled Medium" means the center segment of corrugated shipping containers, being faced with linerboard on both sides. Recycled medium is made from recycled fibers.

(238) "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.

(239) "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).

(240) "Register," in the context of a compliance instrument, means the act of entering the serial number of a compliance instrument into an account.

(241) "Registrant" or "Registered Entity" means an entity that has completed the process for registration.

(242) "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 and issued as an ARB offset credit.

(243) "Registry Services" means all services provided by an ARB approved Offset Project Registry in section 95987.

(244) "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.

(245) "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.

(246) "Renewable Liquid Fuels" means fuel ethanol, biomass-based diesel fuel, other renewable diesel fuel and other renewable fuels.

(247) "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.

(248) "Reporting Year" means data year.

(249) "Reserve Price" see "Auction Reserve Price."

(250) "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.

(251) "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.

(252) "Retail Provider" means an entity that provides electricity to retail end users in California and is an electric 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.

(253) "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.

(254) "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.

(255) "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.

(256) "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.

(257) "Sector-Based Offset Credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached.

(258) "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.

(259) "Serial Number" means a unique number assigned to each compliance instrument for identification.

(260) "Sequestration" means the removal and storage of carbon from the atmosphere in GHG sinks or GHG reservoirs through physical or biological processes.

(261) "Soda Ash Equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, and Sulfate produced.

(262) "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.

(263) "Source" means greenhouse gas source; or any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(264) "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.

(265) "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.

(266) "Stationary" means neither portable nor self-propelled, and operated at a single facility.

(267) "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.

(268) "Supplier" means a producer, importer, exporter, position holder, or local distribution company of a fossil fuel or an industrial greenhouse gas.

(269) "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.

(270) "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.

(271) "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.

(272) "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.

(273) "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.

(274) "Transfer" of a compliance instrument means the removal of the serial number of a compliance instrument from one account and placement into another account.

(275) "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.

(276) "Tribe" means a federally-recognized Indian tribe and any entity created by a federally-recognized Indian Tribe.

(277) "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.

(278) "Unspecified Source of Electricity" or "Unspecified Source" means electricity generation that cannot be matched to a specific electricity generating facility or electricity generating unit or matched to an asset-controlling supplier recognized by ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.

(279) "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).

(280) "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.

(281) "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.

(282) "Verifier" means an individual accredited by ARB to carry out offset verification services as specified in sections 95977.1 and 95977.2.

(283) "Vintage Year" means the budget year to which an individual Californian GHG allowance is assigned pursuant to subarticle 6.

(284) "Voluntarily Associated Entity" 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.

(285) "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.

(286) "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.

(287) "Voluntary Renewable Electricity Generator" means any entity that produces renewable electricity and applies for allowance retirement pursuant to section 95841.1.

(288) "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.

(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) "CAISO" means the California Independent System Operator.

(6) "CAR" means Climate Action Reserve.

(7) "CEC" means California Energy Commission.

(8) "CFR" means Code of Federal Regulations.

(9) "CH_4" means methane.

(10) "CO_2" means carbon dioxide.

(11)"CO_2e" means carbon dioxide equivalent.

(12) "CRT" means Climate Reserve Tonne.

(13) "DWR" means California Department of Water Resources.

(14) "F" means Fahrenheit.

(15) "GHG" means greenhouse gas.

(16) "GHG ETS" means greenhouse gas emissions trading system.

(17) "GWP" means global warming potential.

(18) "HFC" means hydrofluorocarbon.

(19) "LPG" means liquefied petroleum gas.

(20) "MMBtu" means one million British thermal units.

(21) "MRR" means the Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

(22) "Mscf" means one thousand standard cubic feet.

(23) "MWh" means megawatt-hour.

(24) "MT" means metric tons.

(25) "NAICS" means North American Industry Classification System.

(26) "NGLs" means natural gas liquids.

(27) "NERC" means North American Electric Reliability Corporation.

(28) "N_2O" means "nitrous oxide."

(29) "PFC" means perfluorocarbon.

(30) "PSE" means purchasing-selling entity.

(31) "PUC" means the Public Utilities Commission.

(32) "REC" means Renewable Energy Credit.

(33) "REDD" means reducing emissions from deforestation and degradation.

(34) "SCF" means standard cubic foot.

(35) "SF_6" means sulfur hexafluoride.

(36) "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.

§ 95810. Covered Gases.

This article applies to the following greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), nitrogen trifluoride (NF_3), and other fluorinated greenhouse gases.

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.

§ 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) Lime manufacturing;

(7) Nitric acid production;

(8) Petroleum and natural gas systems, as specified in section 95852(h);

(9) Petroleum refining;

(10) Pulp and paper manufacturing;

(11) Self-generation of electricity; or

(12) Stationary combustion.

(b) First Deliverers of Electricity.

(1) Electricity generating facilities: the operator of an electricity generating facility located in California; or

(2) Electricity importers.

(c) Suppliers of Natural Gas. An entity that distributes or uses natural gas in California as 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 95811(c)(1) or section 95811(c)(2) that distributes natural gas directly to end users.

(d) Suppliers of RBOB and Distillate Fuel Oil. A position holder of one or more of the following fuels, or an enterer that imports one or more of the following fuels into California:

(1) RBOB;

(2) Distillate Fuel Oil No. 1; or

(3) Distillate Fuel Oil No. 2.

(e) Suppliers of Liquefied Petroleum Gas.

(1) The operator of a refinery that produces liquid petroleum gas in California;

(2) The operator of a facility that fractionates natural gas liquids to produce liquid petroleum gas; or

(3) A consignee of liquefied petroleum gas into California as defined under MRR.

(f) Sections 95811(c), (d), and (e) apply to suppliers of blended fuels that contain the fuels listed above.

(g) 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.

(a) The inclusion threshold for each covered entity is based on the subset of greenhouse gas emissions that generate a compliance obligation for that entity as specified in section 95852. The entity must report and verify annual emissions pursuant to sections 95100 through 95157 of MRR.

(b) If an entity's reported or reported and verified annual emissions in any data year from 2008 to 2011 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.

(c) The requirements apply as follows:

(1) Operators of Facilities. The applicability threshold for a facility is 25,000 metric tons or more of CO_2e per data year.

(2) First Deliverers of Electricity.

(A) Electricity Generating Facilities. The applicability threshold for an electricity generating facility is based on the annual emissions from which the electricity originated. The applicability threshold for an electricity generating facility is 25,000 metric tons or more of CO_2e per data year.

(B) Electricity importers. The applicability threshold for an electricity importer is based on the annual emissions from each of the electricity importer's sources of delivered electricity.

1. All emissions reported for imported electricity from specified sources of electricity that emit 25,000 metric tons or more of CO_2e per year are considered to be above the threshold.

2. All emissions reported for imported electricity from unspecified sources are considered to be above the threshold.

(3) Carbon Dioxide Suppliers. The applicability threshold for a carbon dioxide supplier is 25,000 metric tons or more of CO_2e per year. For purpose of comparison to this threshold, the supplier must include the sum of the CO_2 that it captures from its production process units for purposes of supplying CO_2 for commercial applications or that it captures from a CO_2 stream to utilize for geologic sequestration, and the CO_2 that it extracts or produces from a CO_2 production well for purposes of supplying for commercial applications or that it extracts or produces to utilize for geologic sequestration.

(4) Petroleum and Natural Gas Facilities. The applicability threshold for a petroleum and natural gas facility 25,000 metric tons or more of CO_2e per data year. This threshold is applied for each facility type specified in section 95852(h).

(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), 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 (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.

(e) Effect of Reduced Emissions on an Entity's Compliance Obligation. A covered entity continues to have a compliance obligation for each data year of a compliance period, until the subsequent compliance period after one of the following conditions occurs:

(1) Annual reports demonstrate GHG emissions less than 25,000 metric tons of CO_2e per year during one entire compliance period; or

(2) A covered entity has ceased reporting and shuts down all processes, units, and supply operations subject to reporting, and has followed the requirements of section 95101(h) of MRR.

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.

(a) An entity that meets the requirements of section 95811, but does not exceed the inclusion thresholds set forth in section 95812 may elect to voluntarily opt-in to the Cap-and-Trade Program.

(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). The Executive Officer shall evaluate such applications and designate approved applicants as opt-in covered entities.

(c) An opt-in covered entity is subject to all reporting, verification, enforcement, and compliance obligations that apply to covered entities.

(d) An opt-in covered entity may be eligible to receive freely allocated allowances subject to subarticles 8 and 9.

(e) Opt-in participation shall not affect the allowance budgets set forth in subarticle 6.

(f) 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. The following entities may qualify as voluntarily associated entities:

(1) An entity that does not meet the requirements of sections 95811 and 95813 that intends to purchase, hold, sell, or voluntarily retire compliance instruments;

(2) An entity operating an offset project or early action offset project that is registered with ARB pursuant to subarticles 13 or 14; or

(3) 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)).

(b) Other Registered Participants.

(1) The following entities do not qualify to hold compliance instruments but may qualify as a Registered Participant:

(A) An offset verifier accredited pursuant to section 95978;

(B) A verification body accredited pursuant to section 95978;

(C) Offset Project Registries; or

(D) Early Action Offset Programs approved pursuant to subarticle 14.

(2) To qualify as a Registered Participant the entity must obtain registration approval from the Executive Officer pursuant to section 95830(c).

(c) A registered entity that has had its holding account revoked pursuant to section 95921(f)(3) may not hold compliance instruments or register with the accounts administrator in the Cap-and-Trade Program in any capacity.

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

§ 95820. Compliance Instruments Issued by the Air Resources Board.

(a) California Greenhouse Gas Emissions Allowances.

(1) The Executive Officer shall create California GHG allowances pursuant to the schedule set forth in subarticle 6.

(2) The Executive Officer shall assign each California GHG allowance a unique serial number that indicates the annual allowance budget from which the allowance originates.

(3) The Executive Officer shall place these allowances into a holding account under the control of the Executive Officer pursuant to section 95831(b).

(b) Offset Credits Issued by ARB.

(1) The Executive Officer shall issue and register ARB offset credits pursuant to the requirements of subarticles 13 and 14.

(2) Surrender of ARB offset credits shall be subject to the quantitative usage limit set forth in section 95854.

(c) Each compliance instrument issued by the Executive Officer represents a limited authorization to emit up to one metric ton in CO_2e of any

greenhouse gas specified in section 95810, subject to all applicable limitations specified in this article. No provision of this article may be construed to limit the authority of the Executive Officer to terminate or limit such authorization to emit. A compliance instrument issued by the Executive Officer does not constitute property or a property right.

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.

§ 95821. Compliance Instruments Issued by Approved Programs.

The following compliance instruments may be used to meet a compliance obligation under this article:

(a) Allowances specified in section 95942(b) and issued by a program approved by ARB pursuant to section 95941;

(b) Offset credits specified in section 95942(c) and issued by a program approved by ARB pursuant to section 95941;

(c) ARB offset credits issued for purposes of early action pursuant to section 95990;

(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.

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.

(a) The Executive Officer shall serve as accounts administrator or may contract with an entity to serve as accounts administrator.

(b) Eligibility and Restrictions:

(1) An entity must qualify for registration pursuant to section 95811,

95813, or 95814.

(2) An entity qualified to register cannot apply for more than one registration.

(3) An entity cannot hold a compliance instrument until the Executive Officer approves the entity's registration with ARB.

(c) Requirements for Registration.

(1) An entity must complete an application that contains the following information:

(A) Name and type of organization;

(B) Statement of basis for qualifying for registration pursuant to sections 95811, 95813, or 95814;

(C) Identification of all other entities registered pursuant to this article with whom the entity has a direct or indirect corporate association pursuant to section 95833, and a brief description of the association;

(D) Identification of all entities registered pursuant to this article for whose benefit the entity holds compliance instruments pursuant to section 95834; and

(E) Applicants may be denied registration based on (i) information provided; or (ii) if the Executive Officer determines the applicant has provided false or misleading information, or has withheld information pertinent to its application.

(2) If an entity qualifies as a voluntarily associated entity pursuant to section 95814(a)(3), then it does not need to include in its registration application pursuant to section 95830(c)(1)(D) information on entities for which it only takes temporary possession of allowances for the purpose of providing a market clearing service for transactions between two entities registered into the Cap-and-Trade Program. It must provide information pursuant to section 95830(c)(1)(D) if it has a corporate association with another registered entity pursuant to section 95833.

(3) An entity must designate an authorized account representative pursuant to section 95832.

(d) Registration Deadlines.

(1) An entity that meets or exceeds the inclusion thresholds in section 95812 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 2008 through 2011.

(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) 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.

(e) Completion of Registration. Registration is completed when the Executive Officer approves the registration and informs the entity and the accounts administrator of the approval.

(f) Updating Registration Information.

(1) 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(f)(3).

(g) Information Confidentiality.

(1) Except when necessary in the course of enforcement investigation and prosecution, the following registration information will be treated by ARB and the accounts administrator as confidential:

(A) Beneficial holding as described in section 95830(c)(1)(D); and

(B) Information relating to the identity of real persons.

(2) All other registration information collected pursuant to section 95830(c) may be made publicly available by the accounts administrator.

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)(3), 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.

(b) Accounts under the Control of the Executive Officer. The accounts administrator will create and maintain the following accounts under the control of the Executive Officer:

(1) A holding account to be known as the Allocation Holding Account into which the serial numbers of compliance instruments will be registered when the compliance instruments are created.

(2) A holding account to be known as the Auction Holding Account into which allowances are transferred to be sold at auction from:

(A) The Allocation Holding Account;

(B) The holding accounts of those entities for which allowances are being auctioned on consignment pursuant to section 95921(f)(3);

(C) The limited use holding accounts of those entities consigning allowances to auction pursuant to section 95910; and

(D) The compliance accounts of entities fulfilling an untimely surrender obligation pursuant to section 95857(d)(1)(A).

(3) A holding account to be known as the Retirement Account to which the Executive Officer will transfer compliance instruments from compliance accounts or from holding accounts under the control of the Executive Officer for the purpose of permanently retiring them. Alternatively, entities may voluntarily retire compliance instruments by transferring the serial numbers of compliance instruments they are retiring to the Retirement Account.

(A) When compliance instruments are registered into the Retirement Account, these compliance instruments cannot be returned to any other holding or compliance account.

(B) When compliance instruments are registered into the Retirement Account, any external ETS to which California links pursuant to subarticle 12 will be informed of the retirements.

(C) The Executive Officer will record the serial numbers of the retired instruments to a publicly available Permanent Retirement Registry.

(4) A holding account to be known as the Allowance Price Containment Reserve Account:

(A) Into which the serial numbers of allowances directly allocated to the Allowance Price Containment Reserve pursuant to section 95870(a) will be transferred; and

(B) From which the Executive Officer will authorize the withdrawal of allowances for sale to covered entities pursuant to section 95913.

(5) A holding account to be known as the Forest Buffer Account:

(A) Into which ARB will place ARB offset credits pursuant to section 95983(a); and

(B) From which ARB may retire ARB offset credits pursuant to sections 95983(b)(2), (c)(3), and (c)(4) and place them into to the Retirement Holding Account.

(6) A holding account to be known as the Voluntary Renewable Electricity Reserve Account, which will be closed when it is depleted of the following originally allocated allowances:

(A) Into which the Executive Officer will transfer allowances allocated pursuant to section 95870(c); and

(B) From which the Executive Officer may retire allowances pursuant to section 95841.1.

(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 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.

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 Authorized Account Representative.

(a) An application for an account must designate a single authorized account representative and a single alternate authorized account representative who may act on behalf of the authorized account representative. The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative. A complete application for an account shall be submitted to the accounts administrator and shall include the following elements:

(1) Name, address, E-mail address, telephone number, and facsimile transmission number of the authorized account representative and any alternate authorized account representative;

(2) Organization name;

(3) A list of all entities subject to a binding agreement for the authorized account representative or any alternate authorized account representative to represent their ownership interest with respect to the compliance instruments held in the account, including a statement of each beneficial owner's percentage ownership interest and a statement of affiliations between beneficial owners;

(4) The authorized account representative and any alternate authorized 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 authorized account representative or the alternate authorized 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";

(5) The signature of the authorized account representative and any alternate authorized account representative and the dates signed; and

(6) An attestation as follows: "I certify 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 submitted to ARB is true, accurate, and complete."

(b) Unless otherwise required by the Executive Officer, documents of agreement referred to in section 95832(a) in the application for an account shall not be submitted to the accounts administrator. The accounts administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(c) Authorization of authorized account representative. Upon receipt by the accounts administrator of a complete application for an account under section 95830(c):

(1) The accounts administrator will establish an account or accounts for the person or persons for whom the application is submitted pursuant to section 95831.

(2) The authorized account representative and any alternate authorized account representative for the account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each entity that owns compliance instruments held in the account in all matters pertaining to this article, notwithstanding any agreement between the authorized account representative or any alternate authorized account representative and such entity.

(3) Any such entity shall be bound by any decision or order issued to the authorized account representative or any alternate authorized account representative by the Executive Officer or a court regarding the account. Any representation, action, inaction, or submission by any

alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative or any alternate authorized account representative.

(d) Each submission concerning the account shall be submitted, signed, and attested to by the authorized account representative or any alternate authorized account representative for the entities that own compliance instruments held in the account. Each such submission shall include the following attestation statement by the authorized account representative or any alternate authorized account representative: "I certify under penalty of perjury under the laws of the State of California that I am authorized to make this submission on behalf of the entities that own the compliance instruments held in the account. 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. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify under penalty of perjury under the laws of the State of California that the statements and information submitted to ARB are true, accurate, and complete." I consent to the jurisdiction of California and its courts for purposes of enforcement of the laws, rules and regulations pertaining to title 17, article 5, sections 95800 et seq., and I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(e) The accounts administrator will accept or act on a submission concerning the account only if the submission has been made, signed, and attested to in accordance with this section.

(f) Changing authorized account representative and alternate authorized account representative; changes in entities that own compliance instruments.

(1) The authorized account representative for an account may be changed at any time upon receipt by the accounts administrator of a superseding complete application for an account under section 95830(c). Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative, or the previous alternate authorized account representative prior to the time and date when the accounts administrator receives the superseding application for an account shall be binding on the new authorized account representative and the entities that own the compliance instruments in the account.

(2) The alternate authorized account representative for an account may be changed at any time upon receipt by the accounts administrator of a superseding complete application for an account under section 95830(c). Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative, or the previous alternate authorized account representative, prior to the time and date when the accounts administrator receives the superseding application for an account shall be binding on the new alternate authorized account representative and the entities that own the compliance instruments in the account.

(3) In the event that a new entity owning compliance instruments in the account is not included in the list of entities in the application for an account, the new entity shall be subject to and bound by the application for an account; the representations, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative; and the decisions, orders, actions, and inactions of the accounts administrator, as if the new entity were included in such list.

(4) Within one day following any change in the entities that own compliance instruments in the account, including the addition or deletion of entities, the authorized account representative or any

alternate authorized account representative shall submit a revision to the application for an account amending the list of entities that own the compliance instruments in the account to include the change.

(g) Objections Concerning Authorized Account Representative.

(1) Once a complete application for an account under section 95830(c) has been submitted and received, the accounts administrator will rely on the application unless and until a superseding complete application for an account under section 95830(c) is received by the accounts administrator.

(2) Except as provided in sections 95832(f)(1), no objection or other communication submitted to the accounts administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative for an account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the accounts administrator under this article.

(3) The accounts administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative for an account, including private legal disputes concerning the proceeds of compliance instrument transfers.

(h) Delegation by authorized account representative and alternate authorized account representative.

(1) An authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the accounts administrator provided for under section 95832(c)(2).

(2) An alternate authorized account representative may delegate, to one or more natural persons, his or her authority to make an electronic

submission to the accounts administrator provided for under section 95832(c)(2).

(3) In order to delegate authority to make an electronic submission to the accounts administrator in accordance with section 95832(h)(1) and (2) the authorized account representative or alternate authorized account representative, as appropriate, must submit to the accounts administrator a notice of delegation, that includes the following elements:

(A) The name, address, email address, telephone number, and facsimile transmission number of such authorized account representative or alternate authorized account representative;

(B) The name, address, email address, telephone number and facsimile transmission number of each such natural person, herein referred to as "electronic submission agent;"

(C) For each such natural person, a list of the type of electronic submissions for which authority is delegated to him or her; and

(D) The following attestations by such authorized account representative or alternate authorized account representative:

1. "I agree that any electronic submission to the accounts administrator that is by a natural person identified in this notice of delegation and of a type listed for such electronic submission agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under section 95832(h)(3) shall be deemed to be an electronic submission by me;" or

2. "Until this notice of delegation is superseded by another notice of delegation under section 95832(h)(3), I agree to maintain an email account and to notify the accounts

administrator immediately of any change in my email address unless all delegation authority by me is terminated."

(4) A notice of delegation submitted under section 95832(h)(3) shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the accounts administrator and until receipt by the accounts administrator of a superseding notice of delegation by such authorized account representative or alternate authorized account representative as appropriate. The superseding notice of delegation may replace any previously identified electronic submission agent, add a new electronic submission agent, or eliminate entirely any delegation of authority.

(5) Any electronic submission covered by the attestation in section 95832(h)(3)(D) and made in accordance with a notice of delegation effective under section 95832(h)(3) shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

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 Direct and Indirect Corporate Associations.

(a) Entities registered pursuant to section 95830 must disclose direct and indirect corporate associations with other registered entities.

(1) An entity has a "direct corporate association" with another entity if any 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; or

(C) Holds more than 50 percent of the voting power of the other entity.

(2) 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) pursuant to section 95833(a)(1).

(3) An entity has an "indirect corporate association" with another entity when:

(A) The two entities are connected through a line of more than one direct corporate association; and

(B) The controlling entity's percentage of ownership or other indicia of control under section 95833(a)(1)(A), (B), or (C) of the indirectly controlled entity is more than 50 percent after multiplying the percentages at each link in the chain of direct corporate associations.

(4) Any registered entity subject to affiliate compliance rules promulgated by state or federal agencies shall not be required to disclose information or take other action that violates other rules.

(b) If California links to one or more GHG ETS pursuant to subarticle 12, then entities shall disclose corporate associations with entities registered with those linked programs.

(c) An entity has a disclosable corporate association if any of the criteria in section 95833(a)(1), (2), or (3) yields a value above 25 percent.

(d) Each registered entity with a disclosable direct or indirect corporate association with another registered entity must disclose the following information:

(1) The name of the other entity;

(2) The type of corporate association (i.e., direct, indirect or disclosable) and a brief description of the association, to include the following information:

(A) Corporate parent;

(B) Subsidiary;

(C) Sister company;

(D) Partnership; and

(E) Other information that describes the relationship.

(e) The entity must disclose the information pursuant to section 95833(c) to the Executive Officer:

(1) When registering pursuant to section 95830;

(2) At any time after registering when a disclosable, direct, or indirect association is created or exists;

(3) Within 30 days of a change to the information disclosed on disclosable, direct and indirect corporate associations; and

(4) No later than the auction registration deadline established in section 95912 when reporting a change to the information disclosed, otherwise the entity may not participate in that 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.

§ 95834. Disclosure of Beneficial Holding Relationships.

(a) There are two types of participants in a beneficial holding relationship, an agent and a principal:

(1) The agent in the beneficial holding relationship is the registered entity acquiring and holding compliance instruments to be transferred to another entity under an agreement with that entity that is disclosed to ARB; and

(2) The principal in the beneficial holding relationship is the registered entity to whom the compliance instruments will be transferred by an agent under an agreement with that entity that is disclosed to ARB.

(3) An electrical distribution utility may serve as the agent in a beneficial holding relationship for a second registered entity with whom it has a contract for the delivery of electricity for the sole purpose of supplying the second entity with compliance instruments to cover emissions resulting from satisfying the electricity contract.

(A) This disclosure must be made to ARB prior to any such purchases, and must include the terms of the contract governing the eventual transfer.

(B) This disclosure must include the principal's confirmation that the electrical distribution utility is authorized to serve as an agent on its behalf.

(C) An entity serving as an agent in this type of a beneficial holding relationship may not also serve as the agent in a beneficial holding relationship with an entity with whom it does not have a contract for the delivery of electricity.

(4) An entity may acquire compliance instruments for the eventual transfer to registered entities that are part of a corporate association to be used for the affiliated entities' compliance obligations. An entity cannot have this type of beneficial holding relationship unless the corporate association is disclosed pursuant to section 95833.

(b) Disclosure of Beneficial Holding.

(1) An entity that establishes an agreement to participate in a beneficial holdings arrangement as either an agent or a principal must report the identity of the second entity in the arrangement, its account information, and the nature of the relationship to the Executive Officer within 10 days of establishing the agreement, notwithstanding the other disclosure requirements in section 95834(a).

(2) The agent will disclose the identity and account number of the principal when acquiring compliance instruments on behalf of a principal when submitting a transfer request to the accounts administrator pursuant to section 95921. The accounts administrator will notify the principal of

the transaction and the principal must confirm the transfer within the time limit specified pursuant to section 95921(a).

(3) After confirmation of the transfer by the principal, the compliance instruments acquired under the transfer and held by the agent will count against the holding limit of the principal and must be transferred to the principal within one year after the agent acquired them.

(c) Multiple Beneficial Holding Relationships. If an entity with a beneficial holding relationship pursuant to section 95834(a)(1) serves as an agent for more than one principal then the entity must either:

(1) Submit a statement to the Executive Officer, under penalty of perjury under the laws of the State of California, that it:

(A) Does not share information on one principal's transaction strategies or holdings with any other principal with whom it has a beneficial holding relationship; and

(B) Conducts separate transactions for each principal with whom it has a beneficial holding relationship; or

(2) Submits a statement to the Executive Officer, that it has a direct or indirect corportate association with the principals with whom it has a beneficial holding relationship.

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

§ 95840. Compliance Periods.

Duration of Compliance Periods is as follows:

(a) The first compliance period starts on January 1, 2013, and ends on December 31, 2014.

(b) The second compliance period starts on January 1, 2015, and ends on December 31, 2017.

(c) The third compliance period starts on January 1, 2018, and ends on December 31, 2020.

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.

§ 95841. Annual Allowance Budgets for Calendar Years 2013-2020.

The California GHG Allowance Budgets are set as described in Table 6-1.

Table 6-1: California GHG Allowances Budgets

	Budget Year	*Annual Allowance Budget (Millions of CA GHG Allowances)*
First Compliance Period	2013	162.8
	2014	159.7
Second Compliance Period	2015	394.5
	2016	382.4
	2017	370.4
Third Compliance Period	2018	358.3
	2019	346.3
	2020	334.2

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.

§ 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.

(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, 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 edition, June 2010;

(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 edition, June 2010, 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 edition, June 2010;

(B) MWhs of renewable electricity generated designated for VRE retirement;

(C) Number of RECs designated for VRE retirement, as applicable; and

(D) REC retirement report 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 edition, June 2010;

(B) MWhs of renewable electricity generated;

(C) Number of RECs, as applicable; and

(D) REC retirement report or tracking system data, as applicable.

(c) The allowances requested to be retired, calculated as follows:

$$\text{Number of MT } CO_2e = \text{MWh} \times \text{EF}$$

Where:

"Number of MT CO_2e," rounded down to the nearest whole ton, is the number of allowances to be retired from the Voluntary Renewable Electricity Reserve Account;

"MWh" is the MWh of voluntary renewable electricity claimed and generated from a generator that meets the requirements of this article; and

"EF" is the CO_2e emissions factor equivalent to the default emission factor for unspecified power, pursuant to section 95111 of MRR.

ARB shall determine the actual MWh of voluntary renewable electricity purchases that occurred during the period indicated in the documentation.

ARB shall retire allowances from the Voluntary Renewable Electricity Reserve Account in an amount up to the number of MT CO_2e represented by actual voluntary renewable electricity purchases, based on actual MWh purchases and the emissions factor determined pursuant to this section.

(d) Once a voluntary renewable electricity tracking system is approved by the Executive Officer and it is in place, a voluntary renewable electricity generator or REC marketer which meets requirements section 95841.1(b) will always be considered to have satisfied section 95841.1(b), if they participate in the tracking system.

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

§ 95850. General Requirements.

(a) Reporting Requirements. Each covered entity identified in section 95811 is subject to MRR.

(b) An entity's compliance obligation is based on the emissions number for the emissions subject to a compliance obligation for every metric ton of CO_2e for which a positive or qualified positive emissions data verification statement is issued, rounded to the nearest whole ton, or for which there are assigned emissions pursuant to MRR.

(c) Record Retention Requirements. Each entity must retain all of the following records for at least 10 consecutive years and must provide such records within 20 calendar days of receiving a written request from ARB, including:

(1) Copies of all data and reports submitted under this article and section 95105 of MRR;

(2) Records used to calculate a compliance obligation as specified in section 95853;

(3) Emissions data and product data verification statements as required pursuant to section 95103(f) of MRR; and

(4) Detailed verification reports as required pursuant to section 95131 of MRR.

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.

§ 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(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 specified in sections 95811(c), (d), (e), and (f) 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.

(a) Operators of Facilities.

(1) An operator of a facility covered under sections 95811(a) and 95812(c)(1) has a compliance obligation for every metric ton of CO_2e for which a positive or qualified positive emissions data verification statement is issued per section 95131 of MRR, including process emissions, stationary combustion emissions and vented emissions. If ARB has assigned emissions for the sources subject to a compliance

obligation pursuant to this section, the facility will have a compliance obligation equal to the value of every metric ton of CO_2e assigned emissions. The entity's compliance obligation will be assessed at the facility level unless otherwise noted under section 95812(c).

(2) Beginning in 2015, combustion emissions resulting from burning RBOB, distillate fuel oils, or natural gas liquids are not included when calculating an operator's compliance obligation.

(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:

$$CO_2e_{covered} = CO_2e_{unspecified} + (CO_2e_{specified} - CO_2e_{specified\text{-}notcovered}) - CO_2e_{RPS_adjustment} - CO_2e_{QE_adjustment} - CO_2e_{linked}$$

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 sections 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.

(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."

(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 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 must be retired 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 generated by the eligible renewable energy resource; or
2. Have a contract to import electricity on behalf of a California entity that has ownership or contract rights to the electricity generated by the eligible renewable energy resource, as verified under MRR.

(B) The RECs associated with the electricity claimed for the RPS adjustment must be used to comply with California RPS

requirements during the same year in 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.

(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) in emissions data reports that received a positive or qualified positive emissions data verification statement, 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.

(d) Suppliers of RBOB and Distillate Fuel Oils. A supplier of petroleum products covered under sections 95811(d) 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 of the following fuels that are removed from the rack in California, sold to entities not licensed by the California Board of Equalization as a fuel supplier, or imported into California and not directly delivered to the bulk-transfer/terminal system as defined in section 95102 of MRR, except for products for which a final destination outside California can be demonstrated:

(1) RBOB;

(2) Distillate Fuel Oil No. 1; and

(3) Distillate Fuel Oil No. 2.

(e) Suppliers of 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.

(f) Suppliers of Blended Fuels. An entity that supplies any of the fuels covered under sections 95811(f) and 95812(d) as blended fuels has an aggregated compliance obligation for every metric ton of CO_2e of GHG emissions based on the separate constituents of the blend 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 fuel.

(g) Carbon Dioxide Suppliers. An entity that supplies carbon dioxide (defined in section 95802(a)(47) covered under sections 95811(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 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.

(h) Petroleum and Natural Gas Systems. Operators of the facilities specified in section 95101(e)(2)-(5) of MRR have a compliance obligation for every metric ton of CO_2e from the source types specified in sections 95152(c)-(f) of MRR, except as specified in section 95852.2 of this article, that is contained in an emissions data report that has received a positive or qualified positive emissions data report, or for which emissions have been assigned.

(i) The compliance obligation for sources specified in sections 95852(a) through (h) 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).

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. Compliance Obligations for Biomass-Derived Fuels.

An entity that has emissions from combustion of biomass-derived fuels is required to report and verify its emissions pursuant to MRR and has a compliance obligation for every metric ton of CO_2e emissions:

(a) From combustion of fuel types that are not listed under section 95852.2; or

(b) From combustion of fuels that do not meet the requirements of section 95852.1.1; or

(c) That are reported as non-exempt biomass derived CO_2 under MRR.

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:

(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 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) 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.

(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 metric tons of CO_2e per ton of captured methane. 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.

Emissions from the following source categories and from the combustion of the following fuel types count toward applicable reporting thresholds, as applicable in MRR, but do not count toward a covered entity's compliance obligation set forth in this article unless those emissions are reported as non-exempt biomass-derived CO_2 under MRR. Emissions without a compliance obligation include:

(a) CO_2 emissions from combustion of the following biomass-derived fuels:

(1) The biogenic fraction of solid waste materials as reported under MRR;

(2) Waste pallets, crates, dunnage, manufacturing and construction wood wastes, tree trimmings, mill residues, and range land maintenance residues;

(3) All agricultural crops or waste;

(4) Wood and wood wastes identified to follow all of the following practices:

(A) Harvested pursuant to an approved timber management plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 or other locally or nationally approved plan; and

(B) Harvested for the purpose of forest fire fuel reduction or forest stand improvement.

(5) Biodiesel:

(A) Agri-biodiesel derived solely from virgin oils, including esters derived from virgin vegetable oils from corn, soybeans, sunflower seeds, cottonseeds, canola, cramble, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, and camelina, and from animal fats.

(B) Biodiesel is defined as monoalkyl esters of long chain fatty acids derived from the following plant or animal matter that meets the requirements of the American Society of Testing Materials (ASTM) D6751:

1. Waste oils;
2. Tallow; or
3. Virgin oils.

(6) Fuel ethanol (including denaturant):

(A) Cellulosic biofuel produced from lignocellulosic or hemicellulosic material that has a proof of at least 150 without regard to denaturants;

(B) Corn starch; or

(C) Sugar cane.

(7) The biogenic fraction of municipal solid waste as reported under MRR, including MSW directly combusted or converted to a cleaner-burning fuel;

(8) Biomethane and biogas from the following sources:

(A) All animal, plant and other organic waste; or

(B) Landfills and wastewater treatment plants;

(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 emissions are estimated using leak detection and leaker emission factors, as required by section 95153(q) of MRR; and

(11) Carbon dioxide that is imported, or that is exported for purposes other than geologic sequestration.

(c) Additional Exemption. The operators of facilities with the NAICS code 92811 are exempt from compliance with this article through December 31, 2013.

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.

(a) A covered entity that exceeds the threshold in section 95812 in any of the three data years preceding the start of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions with a compliance obligation that received a positive or qualified positive emissions data verification statement, or were assigned emissions

pursuant to section 95131 of MRR from all data years of the compliance period.

(b) A covered entity that initially exceeds the threshold in section 95812 in the first year of a compliance period is a covered entity for the entire compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR from all data years of the compliance period.

(c) A covered entity that initially exceeds the threshold in section 95812 in the second year of the second or subsequent compliance period is a covered entity for the second and third years of this compliance period. The covered entity's triennial compliance obligation in this situation is calculated as the total of the emissions that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR for the second and third data years of the compliance period.

(d) A covered entity that initially exceeds the threshold in section 95812 in the second year of the first compliance period or the third year of a later compliance period has a compliance obligation for its emissions that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR for that year, but the entity's triennial compliance obligation for the current compliance period is not due the following year. Instead the entity's reported and verified or assigned emissions for this year will be added to the entity's triennial obligation for the subsequent compliance period.

(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.

§ 95854. Quantitative Usage Limit on Designated Compliance Instruments—Including Offset Credits.

(a) Compliance instruments identified in section 95820(b) and sections 95821 (b), (c), and (d) are subject to a quantitative usage limit when used to meet a compliance obligation.

(b) The total number of compliance instruments identified in section 95854(a) that each covered entity may surrender to fulfill the entity's compliance obligation for a compliance period must conform to the following limit:

O_O/S must be less than or equal to L_O

In which:

O_O = Total number of compliance instruments identified in section 95854(a) submitted to fulfill the entity's compliance obligation for the compliance period.

S = Covered entity's compliance obligation.

L_O = Quantitative usage limit on compliance instruments identified in section 95854(a), set at 0.08.

(c) The number of sector-based offset credits that each covered entity may surrender to meet the entity's compliance obligation for a compliance period must not be greater than 0.25 of the L_O for the first and second compliance periods and not more than 0.50 of the L_O for subsequent compliance periods.

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.

§ 95855. Annual Compliance Obligation.

(a) An entity has an annual compliance obligation for any year when the entity is a covered entity except for the condition specified in section 95853(d); and

(b) The annual compliance obligation for a covered entity equals 30 percent of emissions with a compliance obligation reported from the previous data year that received a positive or qualified positive emissions data verification statement, or were assigned emissions pursuant to section 95131 of MRR.

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.

(a) A covered entity must surrender one compliance instrument for each metric ton of CO_2e of GHG emissions for the annual and triennial compliance obligations calculated pursuant to this subarticle beginning with the emissions data report for 2013 emissions and each subsequent year in which the covered entity has a compliance obligation.

(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 any compliance obligation, a compliance instrument must be issued from an allowance budget year within or before the year for which an annual compliance obligation is calculated or within or before the last year of a compliance period for which a triennial compliance obligation is calculated, unless:

(A) The allowance was purchased from the Allowance Price Containment Reserve pursuant to section 95913; or

(B) The allowance is used to satisfy an excess emissions obligation.

(c) A covered entity must transfer from its holding account to its compliance account a sufficient number of 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 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 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 compliance period, only a triennial compliance obligation.

(e) Determination of Triennial Compliance Obligation.

(1) When a positive or qualified positive emissions data verification statement or assigned emissions for any year is received by ARB, then those emissions for the source categories in section 95852 equal the triennial compliance obligation pursuant to section 95853.

(2) If a positive or qualified positive emissions data verification statement for any year of the compliance period is not received by ARB by the applicable verification deadline as set forth in MRR, ARB will assign emissions according to the requirements set forth in section 95103(g) of MRR for the emissions for the source categories in section 95852. The assigned emissions value then equals the compliance obligation.

(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 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) When the Executive Officer has determined the covered entity has met its compliance obligations, the Executive Officer shall:

(1) Retire the compliance instruments surrendered; and

(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.

§ 95857. Untimely Surrender of Compliance Instruments by a Covered Entity.

(a) Applicability.

(1) A covered entity or opt-in covered entity that does not meet the compliance deadline for surrendering its annual or triennial compliance obligation pursuant to section 95856 is subject to the compliance obligation for untimely surrender as described in this section; and

(2) The compliance obligation for untimely surrender ("excess emissions") will not apply to a covered entity or opt-in covered entity which is determined to have transferred insufficient instruments to meet the compliance obligations of section 95856 solely because of the invalidation of an ARB offset credit by the Executive Officer pursuant to section 95985 until six months after notice of invalidation.

(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), and (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.

(c) If an entity with an untimely surrender obligation fails to satisfy this obligation pursuant to section 95857(b)(6) then:

(1) ARB will determine the number of violations pursuant to section 96014;

(2) If a portion of the untimely surrender obligation is not surrendered as required, the entity will have a new untimely surrender obligation equal to the amount of the previous untimely surrender obligation which was not satisfied by the deadline stated in section 95857(b)(6) upon which the number of violations will be calculated pursuant to section 96014. The new untimely surrender obligation is due immediately; and

(3) The calculation of the untimely surrender obligation shall only apply once for each untimely surrender of compliance instruments per annual or triennial compliance obligation.

(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 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.

§ 95858. Compliance Obligation for Under-Reporting in a Previous Compliance Period.

If, after an entity has surrendered its compliance instruments for a compliance period pursuant to section 95856, the Executive Officer determines, through an audit or other information, that the entity under-reported its emissions under MRR for any emissions sources that form the basis for entity's the compliance obligation, then the following shall apply:

(a) If the difference between the emissions used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856 and the emissions determined by the Executive Officer to be under-reported for the sum of

those emissions is less than five percent of the emissions number used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856, then the entity is not required to take any further action.

(b) If the difference between the emissions used to calculate the compliance obligation and subsequently calculate the number of compliance instruments surrendered pursuant to section 95856 and the emissions determined by the Executive Officer to be under-reported for the sum of those emissions is more than five percent of the emissions number used to calculate the compliance obligation and subsequently used to calculate the number of compliance instruments surrendered pursuant to section 95856, then the entity must surrender compliance instruments in the following amount:

$$\mathrm{Cla} = \mathrm{EMd} - \mathrm{CO} - (\mathrm{CO} * 0.05)$$

Where:

'Cla' is the number of additional compliance instruments that must be surrendered to ARB to cover under-reported emissions;

'CO' is the emissions number used to determine the compliance obligation surrendered pursuant to section 95856 for any previous compliance period; and

'EMd' is the number of the emissions determined by the Executive Officer for the sum of the emissions sources subject to a compliance obligation;

(c) The entity will have six months from the time of notification by the Executive Officer to surrender additional compliance instruments for under- reporting emissions under MRR for the previous compliance period as determined pursuant to this section. The provisions of sections 95857 and 96014 shall not apply during these six months. The entity may use compliance instruments from subsequent compliance periods to meet

these requirements. The entity may only use CA GHG allowances or allowances issued by a GHG ETS approved pursuant to subarticle 12 to meet the requirements of this section.

(d) Any determination that an entity under-reported its emissions for a previous compliance period shall be made by the Executive Officer no later than eight years from the applicable verification deadline for the emissions data report which contained the under-reporting of emissions.

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.

(a) Allowance Price Containment Reserve. Upon creation of the Allowance Price Containment Reserve Account, the Executive Officer shall transfer allowances to the Allowance Price Containment Reserve, as follows:

(1) One percent of the allowances from budget years 2013-2014;

(2) Four percent of the allowances from budget years 2015-2017; and

(3) Seven percent of the allowances from budget years 2018-2020.

(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 shall be auctioned pursuant to section 95910.

(2) The proceeds from the sale of these allowances will be deposited into the Air Pollution Control Fund and will be available upon appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq.

(c) Upon creation of the Voluntary Renewable Electricity Reserve Account, the Executive Officer shall transfer allowances to the Voluntary Renewable Electricity Reserve Account, as follows:

(1) 0.5 percent of the allowances from budget years 2013-2014; and

(2) 0.25 percent of the allowances from budget years 2015-2020.

(d) 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 July 15, 2012, or the first business day thereafter, for vintage 2013 allowances and November 1, or first business day thereafter, of each calendar year from 2013-2019 for allocations from 2014-2020 annual allowance budgets.

(e) Allocation to Industrial Covered Entities. Allowances allocated for the purposes of industry assistance shall be transferred to holding accounts for industrial sectors listed in Table 8-1.

(1) The Executive Officer will place an annual individual allocation in the holding account of each eligible covered entity on or before November 1, or the first business day thereafter, of each calendar year 2012-2019 for allocations from 2013-2020 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.

Table 8-1: Industry Assistance

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (AF_A) 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%
	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%
	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	100%	100%	100%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (AF_A)		
			Solution Production			
	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%
	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%
Medium	Food Manufacturing	311	Food Manufacturing	100%	75%	50%
	Cut and Sew Apparel Manufacturing	3152	Cut and Sew Apparel Manufacturing	100%	75%	50%
	Breweries	312120	Brewing	100%	75%	50%
	Petroleum Refineries	324110	Petroleum Refining	100%	75%	50%
	Industrial Gas Manufacturing	325120	Gaseous Hydrogen Production	100%	75%	50%
			Liquefied Hydrogen Production	100%	75%	50%
	Biological Product (Except Diagnostic) Manufacturing	325414	Biological Product (Except Diagnostic) Manufacturing	100%	75%	50%
	Gypsum Product Manufacturing	327420	Plaster Manufacturing	100%	75%	50%
			Plaster Board Manufacturing	100%	75%	50%
	Mineral Wool Manufacturing	327993	Fiber Glass Manufacturing	100%	75%	50%
	Rolled Steel Shape Manufacturing	331221	Picked Steel Sheet Production	100%	75%	50%
			Cold Rolled and Annealed Steel Sheet Production	100%	75%	50%
			Galvanized Steel Sheet Production	100%	75%	50%

Leakage Risk Classification	NAICS Sector Definition	NAICS Code	Activity(a)	Industry Assistance Factor (AF_a)		
			Tin Steel Plate Production	100%	75%	50%
	Secondary Smelting and Alloying of Aluminum	331314	Secondary Smelting and Alloying of Aluminum	100%	75%	50%
	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)	100%	75%	50%
	Iron Foundries	331511	Iron Foundries	100%	75%	50%
	Turbine and Turbine Generator Set Units Manufacturing	333611	Testing of Turbines and Turbine Generator Sets	100%	75%	50%
Low	Pharmaceutical and Medicine Manufacturing	325412	Pharmaceutical and Medicine Manufacturing	100%	50%	30%
	Aircraft Manufacturing	336411	Aircraft Manufacturing	100%	50%	30%
	Support Activities for Air Transportation	4881	Support Activities for Air Transportation	100%	50%	30%

(f) Auction Proceeds for AB 32 Statutory Objectives. All remaining allowances not allocated for uses specified in sections 95870(a) through (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 and will be available for appropriation by the Legislature for the purposes designated in California Health and Safety Code sections 38500 et seq.

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 9: Direct Allocations of California GHG Allowances

§ 95890. General Provisions for Direct Allocations.

(a) Eligibility Requirements for Industrial Facilities. A covered entity or opt-in covered entity from the industrial sectors listed in Table 8-1 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 product data verification statement for the prior year pursuant to MRR.

(b) Eligibility Requirements for Electrical Distribution Utilities. An electrical distribution utility 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.

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 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).

(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:

$$A_t = \sum_{a=1}^{n} O_{a,initial} * B_a * AF_{a,t} * c_{a,t} + \sum_{a=1}^{n} O_{a,trueup} * B_a * AF_{a,t-2} * c_{a,t-2}$$

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;

"$O_{a,\ initial}$" 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.

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	Allowances / Barrel of Thermal Crude Oil Eqv.
		Non Thermal Crude Oil Extraction	0.0082	Allowances / Barrel of Non Thermal Crude Oil Eqv.
Natural Gas Liquid Extraction	211112	Natural Gas Liquid Processing	0.0146	Allowances / Barrel of Natural Gas Liquids Produced
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)

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Paper (except Newsprint) Mills	322121	Tissue Manufacturing	1.14	Allowances / Air Dried Short Ton of tissue
Paperboard Mills	322130	Recycled Boxboard Manufacturing	0.499	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	Allowances / Short Ton of Flat Glass Pulled
Glass Container Manufacturing	327213	Container Glass Manufacturing	0.264	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	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
		Plaster Board Manufacturing	0.134	Allowances / Short Ton of Plaster Board
Iron and Steel Mills	331111	Steel Production Using an Electric Arc Furnace	0.170	Allowances / Short ton of Steel produced using EAF

NAICS Sector Definition	NAICS code	Activity (a)	Benchmark (B_a)	Benchmark Units
Rolled Steel Shape Manufacturing	331221	Hot Rolled Steel Sheet Production	0.0843	Allowances / Short ton of hot rolled steel
		Picked Steel Sheet Production	0.0126	Allowances / Short ton of pickled steel
		Cold Rolled and Annealed Steel Sheet Production	0.0313	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	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:

$$A_t = \left(S_{Consumed} * B_{Steam} + F_{Consumed} * B_{Fuel} - e_{Sold} * B_{Electricity}\right) * AF_{a,t} * c_{a,t}$$

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;

"$S_{Consumed}$" 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 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.

(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. Covered entities of facilities that were not in operation prior to 2011 and are eligible for free allocation under the energy-based methodology shall be assessed a baseline annual allocation based on expected activity levels as determined by the Executive Officer.

(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:

$$\text{If: } O_{X,t-2} * B_R * c_t * AF_{R,t} \leq BE_X * c_t * AF_{R,t}$$
$$\text{Then: } A_{X,t} = O_{X,t-2} * B_R * c_t * AF_{R,t}$$

$$\text{If: } O_{X,t-2} * B_R * c_t * AF_{R,t} > BE_X * c_t * AF_{R,t}$$
$$\text{Then: } A_{X,t} = BE_X * c_t * AF_{R,t}$$

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.

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

Where:

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

(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: $A_{Y,Credit} = (AE_{Y,2013} * DF_{Y,2013} * F_{2013} * AF_{2013} + AE_{Y,2014} * DF_{Y,2014} * F_{2014} * AF_{2014}) - (A_{Y,2013} + A_{Y,2014})$

Where:

"$A_{Y,Credit}$" = An additional true-up allocation distributed by the Executive Officer to refinery "Y" using 2015 vintage allowances.

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	327311	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.

(a) Allocation to Individual Electrical Distribution Utilities. The allowances allocated to each electrical distribution utility from each budget year shall be the electrical distribution utility sector allocation calculated pursuant to section 95870(d) for the budget year multiplied by the percentage allocation factors specified in Table 9-3. Any allowance allocated to electrical distribution utilities must be used exclusively for the benefit of retail ratepayers of each such electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(b) Transfer to Utility Accounts.

(1) Investor Owned Utilities. The Executive Officer will place allowances in the limited use holding account created for each electrical corporation.

(2) Publicly Owned Electric Utilities or Electrical Cooperatives. When allocating to a publicly owned electric utility or an electrical cooperative, the Executive Officer will place allowances in either a limited use holding account or in a compliance account per the entity's preference. Prior to receiving a direct allocation of allowances, publicly owned electric utilities or electrical cooperatives will inform the Executive Officer of the share of their allowances that is to be placed:

(A) In the compliance account of an electrical generating facility operated by a publicly owned electric utility, an electrical cooperative, or a Joint Powers Agency in which the electrical distribution utility or electrical cooperative is a member and with which it has a power purchase agreement; or

(B) In the publicly owned electric utility's or electrical cooperative's limited use holding account.

(c) Monetization Requirement.

(1) In 2012 an electrical distribution utility must offer one sixth of the allowances placed in its limited use holding account in 2012 for sale at each of the two auctions scheduled for 2012.

(2) Within each calendar year after 2012, an electrical distribution utility must offer for sale at auction all allowances in a limited use holding account that were issued:

(A) From budget years that correspond to the current calendar year; and

(B) 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 electric utility shall be subject to any limitations imposed by the governing body of the utility and to the additional requirements set forth in sections 95892(d)(3-5) and 95892(e).

(2) Proceeds obtained from the monetization of allowances directly allocated to investor owned utilities shall be subject to any limitations imposed by the California Public Utilities Commission and to the additional requirements set forth in sections 95892(d)(3-5) and 95892(e).

(3) Auction proceeds and allowance value obtained by an electrical distribution utility shall be used exclusively for the benefit of retail ratepayers of each electrical distribution utility, consistent with the goals of AB 32, and may not be used for the benefit of entities or persons other than such ratepayers.

(4) Investor owned utilities shall ensure equal treatment of their own customers and customers of electricity service providers and community choice aggregators.

(5) Prohibited Use of Allocated Allowance Value. Use of the value of any allowance allocated to an electrical distribution utility, other than for

the benefit of retail ratepayers consistent with the goals of AB 32 is prohibited, including use of such allowances to meet compliance obligations for electricity sold into the California Independent System Operator markets.

(e) Reporting on the Use of Auction Proceeds and Allowance Value. No later than June 30, 2013, and each calendar year thereafter, each electrical distribution utility 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 electrical distribution utility;

(2) How the electrical distribution utility'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 electrical distribution utility which were deposited directly into electrical generating facility compliance accounts. The electrical distribution utility 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

(4) How the electrical distribution utility's disposition of the monetary value of allowances, deposited directly into compliance accounts, complies with the requirements of this section and the requirements of California Health and Safety Code sections 38500 et seq.

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%

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%	0.02181%	0.02237%	0.02320%	0.02348%	0.02405%	0.02443%
Bear Valley Electric Service	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	IOU	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	POU	0.22625%	0.23453%	0.24340%	0.24957%	0.25888%	0.26194%	0.26839%	0.27259%

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%	0.05789%	0.05936%	0.06158%	0.06230%	0.06384%	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 for Protection of Natural Gas Ratepayers.

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, auctions will be held on August 15 and November 14.

(2) Beginning in 2013, auctions shall be conducted on the twelfth business day of the second month of each calendar quarter.

(b) An allowance may be designated for auction prior to its vintage year.

(c) The Executive Officer will conduct two separate auctions each quarter.

(1) Auction of Allowances from the Current and Previous Budget Years.

(A) Beginning in 2013, one quarter of the allowances designated for auction from the current calendar year's budget will be offered pursuant to section 95870(f).

(B) This auction will include allowances consigned to auction pursuant to section 95910(d).

(C) Advanced auctions may include allowances which were returned to the Auction Holding Account following an auction which resulted in unsold allowances, and which are returned to auction pursuant to 95911(b)(4).

(2) Auction of Allowances from Future Budget Years.

(A) At each auction taking place in 2012, one half of the allowances designated for advance auction pursuant to section 95870(b) will be offered from the 2015 budget.

(B) Beginning in 2013, one quarter of the allowances designated for advance auction pursuant to 95870(b) from the budget year

three years subsequent to the current calendar year will be offered at each auction.

(C) This auction will include allowances which were returned to the Auction Holding Account following an auction which resulted in unsold allowances, and which are returned to auction pursuant to 95911(b)(4).

(3) Auctions of allowances from different budget years will be conducted separately.

(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) or accounts suspended or revoked pursuant to section 95921(f)(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 auctions 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 each auction.

(B) Beginning in 2013, 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.

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.

(a) Auction Bidding Format.

(1) The auction will consist of a single round of bidding.

(2) Bids will be sealed.

(3) Bid quantities must be submitted as multiples of 1,000 California GHG allowances.

(4) Bid prices must be submitted in whole dollars and whole cents.

(b) Auction Reserve Price Schedule.

(1) Each auction will be conducted with an auction reserve price.

(2) No allowances will be sold at bids lower than the auction reserve price.

(3) If an auction settlement price equals the reserve price:

(A) The auction operator will fulfill winning bids with allowances from consignment sources in the following order:

1. Allowances consigned to auction pursuant to section 95910(d)(2);

2. Allowances consigned from limited use holding accounts pursuant to section 95910(d)(1);

3. Allowances directly allocated by ARB to auction pursuant to subarticle 8 and allowances returned to the auction pursuant to section 95911(b)(4).

(B) When there are insufficient winning bids to exhaust the allowances from a consignment source in section 95911(b)(3)(A), the auction operator will sell an equal proportion of allowances from each consigning entity in that source.

(4) Disposition of Allowances Allocated for Auction when an Auction Settlement Price Equals the Reserve Price.

(A) Allowances designated by ARB for an auction which remain unsold when the auction settlement price equals the Auction

Reserve Price shall be returned to the Auction Holding Account to be re-auctioned.

(B) Allowances returned to the Auction Holding Account will be re-designated for auction after two consecutive auctions have resulted in an auction settlement price greater than the applicable Auction Reserve Price. This requirement applies separately to the current vintage and future vintage auctions.

(C) The number of allowances returned to each subsequent current vintage or future vintage auction will not exceed 25 percent of allowances already designated by ARB for that auction.

(5) Disposition of Consigned Allowances Remaining Unsold at Auction.

(A) Allowances consigned to auction from limited use holding accounts that remain unsold at auction will be returned to the respective source accounts.

(B) Allowances consigned to auction pursuant to section 95921(f)(3) that remain unsold at auction will be held in the Auction Holding Account until the next auction.

(6) Method for Setting the Auction Reserve Price.

(A) For auctions conducted in calendar year 2012 and 2013 the Reserve Price shall be $10 per metric ton of CO_2e for vintage 2013 allowances. For auctions conducted in 2012, the Reserve Price shall be $10 per metric ton of CO_2e for vintage 2015 allowances.

(B) For auctions conducted in calendar years after 2013 the Reserve Prices shall be the Auction Reserve Prices for the previous calendar year increased annually by 5 percent plus the rate of inflation as measured by the Consumer Price Index for All Urban Consumers.

(c) 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 disclosable corporate association pursuant to section 95833.

(2) The auction purchase limit 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) the purchase limit is 25 percent.

(4) For the auction of current vintage allowances:

(A) The purchase limit for covered entities and opt-in covered entities will be 15 percent of the allowances offered for auction;

(B) The purchase limit does not apply to electrical distribution utilities receiving a direct allocation of allowances pursuant to section 95892(b) and subject to the monetization requirement pursuant to section 95892(c). This provision shall not be interpreted to exempt said electrical distribution utilities from any other requirements of this article; and

(C) The purchase limit for all other auction participants is four percent of the allowances offered for auction.

(d) 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 will be considered in declining order by price, and the auction operator shall reject a bid:

(A) If acceptance of the bid would result in violation of the purchase limit pursuant to sections 95911(c) 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(h).

(4) Beginning with the highest bid price, bids will be considered in declining order by price and entities submitting bids at that price will be sold allowances until either:

(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(d)(5) shall apply.

(5) Resolution of tie bids:

(A) If the quantity of allowances contained in the bids placed at the lowest bid is greater than the quantity of allowances available to be sold at that price, then the auction operator will assign a random number to each bundle of 1,000 CA GHG Allowances contained in each of the bids at that price.

(B) Beginning with the lowest random number assigned and working in increasing order of the random numbers assigned, the auction operator shall sell allowances to the bidder assigned the random number until the remaining allowances are sold.

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 Registration.

(a) Administration of the Auctions.

(1) The Executive Officer may serve as auction administrator or designate an entity to serve as auction administrator.

(2) The Executive Officer may serve as financial services administrator or may designate a qualified financial services administrator to conduct all financial transactions required by this article.

(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 this article.

(c) Auction Registration Requirements. An entity that intends to participate in the auction must complete an auction registration at least 30 days prior to the auction.

(1) The details of the auction and the requirements for auction registration will be provided in a public notice by the auction administrator no later than 60 days prior to the auction.

(2) An entity will be required to complete an auction registration application at least 30 days prior to an auction in which it intends to participate. 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(e);

(C) Declarations as to the beneficial holding, pursuant to section 95914, of any compliance instrument that may be acquired through the auction or that already exists prior to the auction;

(D) The identification of any previous or pending investigation with respect to any alleged violation of any rule, regulation, or law associated with any commodity market or exchange; and

(E) The applicant's holding account number.

(3) The Executive Officer must approve an entity's auction registration before that entity may participate in an auction.

(d) Maintenance and Modification of Auction Registration.

(1) Once the Executive Officer has approved an entity's auction registration, the entity need not complete another application for subsequent auctions unless there is a material change to the information contained in the application or the Executive Officer has made a determination restricting an entity's auction participation pursuant to section 95914(c).

(2) An entity approved for auction participation must inform the auction operator 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.

(e) A registered entity 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 operator to remediate an auction application.

(f) Protection of Confidential Information.

(1) 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 as confidential business information.

(2) Following the auction, the Executive Officer will release 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.

(g) All bids shall be submitted to the Executive Officer and will be considered binding offers for the purchase of allowances under the rules of the auction.

(h) Registrants must provide a bid guarantee to the financial services administrator at least one week prior to the auction.

(1) The bid guarantee must be in one or a combination of the following forms:

(A) A bond issued by a financial institution with a United States banking license;

(B) Cash in the form of a wire transfer or certified funds, such as a bank check or cashier's check;

(C) An irrevocable letter of credit issued by a financial institution with a United States banking license; or

(D) If California participates in a joint auction with one or more Canadian Provinces pursuant to section 95912(b) then bonds or irrevocable letters of credit issued by a financial institution with a Canadian banking license will be acceptable.

(2) The amount of the bid guarantee must be greater than or equal to the sum of the value of the bids submitted by the auction participant.

(i) At least 60 days prior to each auction the auction administrator shall publish the following information:

(1) The date and time of the auction;

(2) Application instructions for applying to participate in the auction;

(3) The form and manner for submitting bids;

(4) The procedures for conducting the auction;

(5) The administrative requirements for participation; and

(6) The number of CA GHG Allowances that will be available at each auction.

(j) To conduct the auction the auction administrator will:

(1) Obtain a determination from the financial services administrator of the acceptance of the registration bid guarantees;

(2) Determine that bids and bid quantities conform with purchase limits set for the auction pursuant to section 95911(c), the holding limit pursuant to section 95920(b), and the amount of the bid guarantee provided by the registrant;

(3) Determine the winning bids and auction price; and

(4) Inform the Executive Officer of the auction results.

(k) Following the auction, the Executive Officer will:

(1) Certify whether the auction was operated pursuant to this article;

(2) After certification, direct the financial services administrator to:

(A) Collect payments from winning bidders;

(B) Declare forfeit and retain the bid guarantee mechanism submitted pursuant to section 95912(h) for any bidder that fails to tender full payment when due for allowances awarded at auction, in an amount equal to any unpaid balance;

(C) Deposit auction proceeds from sales of ARB allowances sold at auction into the Air Pollution Control Fund; and

(D) Distribute auction proceeds to entities that consigned allowances for auction pursuant to section 95910(d);

(3) Upon determining that the payment for allowances has been deposited into the 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) Publish the auction results in the manner set forth in section 95912 at www.arb.ca.gov.

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.

§ 95913. Sale of Allowances from the Allowance Price Containment Reserve.

(a) The Executive Officer may serve as reserve sale administrator to conduct sales from the Allowance Price Containment Reserve (Reserve) or designate an entity to serve as reserve sale administrator. The financial

services administrator designated by the Executive Officer pursuant to section 95912(a) will conduct the financial transactions required to operate sales from the Reserve.

(b) 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.

(c) Timing, Eligible Participants, and Limitations.

(1) Eligible Participants. Only covered entities (including opt-in covered entities) registered as provided in sections 95811 or 95813 shall be eligible to purchase allowances from the Reserve.

(2) The reserve sale administrator of the Reserve shall offer all of the allowances in the Reserve at each reserve sale.

(3) Timing of Reserve Sale.

(A) The first Reserve sale will be conducted on March 8, 2013.

(B) Subsequent sales shall be conducted six weeks after each quarterly allowance auction pursuant to section 95910.

(C) The Reserve sale administrator shall provide all eligible participants with written notice of the number of allowances available for sale and the terms of the sale at least four weeks prior to the sale.

(4) Limitation. Allowances purchased from the Reserve are subject to the Holding Limit established pursuant to section 95920.

(d) Reserve Tiers.

(1) Creation of Reserve Tiers. Prior to the first Reserve sale, the reserve sale administrator shall divide allowances allocated to the Reserve into three equal-sized tiers.

(2) 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.

(3) Increase in Release Prices. In calendar years subsequent to 2013, allowances from each tier shall be offered at prices equal to the offer price for each tier from the previous calendar year increased by five percent plus the rate of inflation as measured by the Consumer Price Index for All Urban Consumers.

(e) Submissions of Bids to Purchase. At least two weeks prior to the scheduled sale, an entity shall submit:

(1) To the reserve sale administrator a bid consisting of a price equal to one of the three tier prices and a quantity of allowances; and

(2) To the financial services administrator a bid guarantee in an amount greater than or equal to the sum of the maximum value of the bids submitted by the entity, in one or a combination of the following forms:

(A) A bond issued by a financial institution with a United States banking license;

(B) Cash in the form of a wire transfer or certified funds, such as a bank check or cashier's check;

(C) An irrevocable letter of credit issued by a financial institution with a United States banking license; or

(D) If California participates in a joint Allowance Price Containment Reserve with one or more GHG ETS programs in the Canadian Provinces to which it links and covered entities from linked systems are eligible to purchase from the Reserve pursuant to section 95913(b), then bonds or irrevocable letters of credit issued by a financial institution with a Canadian banking license will be acceptable.

(E) 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 financial services administrator.

(f) Purchase Determinations.

(1) The reserve sale administrator will conduct sales from each tier in succession, beginning with the lowest to the highest priced tier, until either all allowances are sold from the reserve or all the accepted bids are filled.

(2) The reserve sale administrator will only accept a bid:

(A) If acceptance of the bid would not result in violation of the holding limit pursuant to section 95920(b); or

(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(e)(2).

(3) 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(f)(3)(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 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.

(4) 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 (f)(4)(A) above by the number of allowances in the tier, rounding the number down to the nearest whole number.

(5) After completing the sales for each tier the reserve sale administrator will repeat the processes in sections 95913(f)(3) and (f)(4) 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.

(g) Resolution of Sales. Following each sale of allowances from the Reserve, the Executive Officer shall:

(1) Certify that the reserve sale administrator conducted the reserve sale pursuant to this article;

(2) Upon certification of the sale results, authorize the financial services administrator to process payments from covered entities and deposit proceeds into the Air Pollution Control Fund;

(3) Upon determining that the financial services administrator has deposited the payment for allowances into the Air Pollution Control Fund, transfer the serial numbers of the allowances purchased from the Allowance Price Containment Reserve Account into each winning bidder's compliance account;

(4) Inform each approved external GHG emissions trading system and the associated tracking system of the serial numbers of allowances sold; and

(5) Publish the sale results at www.arb.ca.gov.

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) An entity registering as an auction participant must be registered as provided in sections 95830.

(b) An entity whose holding account has been revoked or is currently suspended pursuant to section 96011 cannot participate in an auction.

(c) If the Executive Officer determines that a bidder has provided false or misleading facts, or has withheld material information in its application, or has violated any part of the auction rules set forth in subarticle 10, then:

(1) The Executive Officer may instruct the auction operator to not accept auction applications from the bidder or any agent or affiliate of the bidder intending to purchase allowances at auction for subsequent transfer to the bidder through either a beneficial holding or corporate association pursuant to sections 95833 and 95834.

(2) This exclusion from auction participation shall be in addition to any other penalties, fines, and additional remedies available at law.

(3) This exclusion from auction participation may be permanent or for a specified number of auctions.

(4) A fact is material if it could probably influence a decision by the Executive Officer, the Board, or the Board's staff.

(d) Non-disclosure of Bidding Information Among Auction Participants.

(1) An entity approved for auction participation shall not release any confidential information related to its auction participation, including:

(A) Qualification status;

(B) Bidding strategy;

(C) Bid price or bid quantity information;

(D) Information on the financial security it provided to the auction administrator; and

(E) Other information identified in the auction application by the auction administrator.

(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.

(3) Restrictions on disclosure of information on auction participation between members of a beneficial holding relationship.

(A) A principal may only disclose confidential information related to its auction participation with another principal or with more than one agent.

(B) An agent in a beneficial holding relationship may not disclose confidential information related to auction participation to anyone other than the principal who made the original disclosure.

(4) Any disclosure of auction participation information to entities that are not subject to exclusion pursuant to section 95914(d)(1) shall be a violation of this article and subject to penalties pursuant to section 96013.

(e) 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 or indirect corporate association is limited pursuant to section 95911(c).

(2) Entities that are part of a direct or indirect corporate association may allocate shares of the purchase limit amongst themselves. 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:

(A) The group of associated entities must inform the Executive Officer when submitting the auction application of an allocation of the purchase limit among the associated entities, if applicable;

(B) The purchase limit allocation will be in effect for the auction for which the associated entities submitted the application; and

(C) Each associated entity's allocated purchase limit share times the auction purchase limit becomes the purchase limit for that entity.

(3) If entities with a direct or indirect 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.

(a) The holding limit is the maximum number of California GHG allowances that may be held by an entity or jointly held by a group of entities with a direct or indirect corporate association, as defined in section 95833 at any point in time.

(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 contained in an exchange clearing holding account will be included in the calculation of the holding limit for the entity listed as the purchaser in the transfer request reported to the accounts administrator pursuant to section 95921 for the transfer request being cleared.

(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(b)(1). If the violation is not discovered until after the transfer request is recorded, then the transfer request may be reversed pursuant to section 95921(b)(2) and penalties may be imposed pursuant to section 96013.

(c) The holding limit will be separately calculated to holdings of:

(1) Allowances which may be used to fulfill a compliance obligation during the current compliance year pursuant to section 95856(b), including:

(A) Allowances issued for previous compliance years;

(B) Allowances from any vintage purchased from the Allowance Price Containment Reserve pursuant to section 95913; and

(C) Allowances originally purchased at the advance auction but now usable for compliance during the current compliance year.

(2) Allowances issued for future compliance years that may not be used for compliance during the current compliance year pursuant to section 95856(b).

(d) The holding limit will be calculated for allowances qualifying pursuant to section 95920(c)(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) A Limited Exemption from the Holding Limit is calculated as:

(A) The limited exemption is the number of allowances which are exempt from the holding limit calculation after they are transferred by a covered entity or an opt-in covered entity to its compliance account.

(B) On June 1, 2012 the limited exemption will equal the annual emissions most recent emissions data report that has received a positive or qualified positive emissions data verification statement.

(C) Beginning in 2013 on October 1 of each year the limited exemption will be increased by the amount of emissions contained in the most recent emissions data report that has received a positive or qualified positive emissions data verified statement during that year.

(D) 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) 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)(E).

(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.

(e) The holding limit will be calculated for allowances qualifying pursuant to section 95920(c)(2) as the number given by the following formula:

Holding Limit = 0.1*Base + 0.025*(Compliance Period Budget – Base)

In which:

"Base" equals 75 million metric tons of CO_2e.

"Compliance Period Budget" is the number of allowances issued for the future compliance period from which the allowances were sold at the advance auction.

(f) Application of the Corporate Association Disclosure to the Holding Limit.

(1) The total number of allowances held by a group of entities with a direct or indirect corporate association pursuant to section 95833 in their holding accounts must sum to less than the holding limit pursuant to section 95920(e).

(2) The limited exemption for each entity which is part of a direct or indirect corporate association is the same as defined in section 95920(f).

(3) Entities that are part of a corporate association may allocate shares of the holding limit among themselves. This holding limit allocation results in each entity having a specified percentage share of the group's holding limit. The sum of the shares allocated among the entities must sum to one.

(A) The group of associated entities must inform the accounts administrator of the allocation of the holding limit when registering pursuant to section 95833.

(B) The holding limit allocation will remain in effect until the group of associated entities informs the accounts administrator of subsequent changes to the allocation of the holding limit.

(4) If entities with a direct or indirect corporate association do not allocate shares of the holding limit among themselves, the accounts administrator will not record any transfer request which would result in the entities with a direct or indirect corporate association exceeding the holding limit.

(g) The application of the holding limit will treat beneficial holding by an agent as part of the holding of the principal.

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:

(A) The two parties to the transfer submit a request for the transfer to the accounts administrator within three calendar days of settlement of the transaction agreement; and

(B) The Executive Officer has determined the transfer request and the transaction meet the requirements of this article.

(2) Except when a transfer is undertaken by the Executive Officer, all transfers between two entities will involve transfers between holding accounts and/or an exchange clearing holding account.

(b) Deficient Transfer Requests

(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 and the Executive Officer of the deficiency;

(B) The entities submitting the transfer request may resubmit the request with the deficiency corrected within the time limit set pursuant to section 95921(a)(1)(A); and

(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 request for transfer.

(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 and the Executive Officer of the deficiency; and

(B) If the entities that submitted the deficient transfer request cannot correct the deficiency within 5 business days after notification by the accounts administrator, the Executive Officer may instruct the accounts administrator to reverse the transfer.

(c) Information Requirements. 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) Holding account number and authorized account representative of seller;

(2) Holding account number and authorized account representative of purchaser;

(3) Serial number of the compliance instruments;

(4) Date of the transaction agreement;

(5) Settlement date, if not the same as date of transaction agreement;

(6) Price of the compliance instrument in U.S. dollars. If California links to Canadian provinces pursuant to subarticle 12, the price of the compliance instrument may be reported in Canadian dollars; and

(7) Holding account number and authorized representative of an entity for whom the compliance instrument is to be held in benefit;

(d) Protection of Confidential Information. The Executive Officer will ensure that the accounts administrator:

(1) Releases information on the transaction price and quantity of compliance instruments in a timely manner;

(2) Except as needed for market oversight and investigation by the Executive Officer, protects as confidential all other information obtained through transaction reports;

(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.

(e) General Prohibitions on Trading.

(1) An entity cannot acquire allowances and hold them in its own holding account for another entity, except when part of a disclosed beneficial holdings relationship pursuant to section 95834.

(2) A registered entity acquiring a compliance instrument on behalf of another registered entity not part of a disclosed beneficial holdings relationship must designate the holding account of the second entity as the destination account in the transfer request.

(3) 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 regulated 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.

(f) Restrictions on Registered Entities. If an entity registered pursuant to section 95830 violates any provision specified in this article the Executive Officer may:

(1) Reduce the number of compliance instruments a covered entity or opt-in covered entity may have in its holding account below the amount allowed by the holding limit pursuant to section 95920;

(2) Increase the annual surrender obligation for a covered entity or an opt-in covered entity to a percentage of its reported and verified or assigned emissions above the 30% obligation pursuant to section 95855;

(3) Suspend or revoke the registration of opt-in covered entities, voluntarily associated entities, and other entities registered pursuant to section 95830;

(A) If registration is revoked or suspended the entity must sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation; and

(B) If registration is revoked or suspended and the entity fails to sell or voluntarily retire all compliance instruments in its holding account within 30 days of revocation, the accounts administrator will transfer the remaining instruments into the Auction Holding Account for sale at auction on behalf of the entity pursuant to section 95910(d);

(4) Limit or prohibit transfers in or out of the holding account; or

(5) All of the above.

(g) Information Reporting By Holders of Exchange Clearing Holding Accounts

(1) Holders of exchange clearing holding accounts must make the transaction records available to ARB within 10 calendar days of a request from the Executive Officer.

(2) Holders of exchange clearing holding accounts must retain transaction records containing the information listed in 95921(c) for 10 years.

(3) ARB Holders of exchange clearing holding accounts are not required to include the information listed in 95921(c)(4), (5), (6), and (7) in transfer requests to the accounts administrator.

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.

(a) Allowances Issued for a Current or Previous Compliance Period. A CA GHG allowance or an allowance issued by an approved GHG ETS pursuant to subarticle 12 may be held ("banked") by an entity registered pursuant to section 95830.

(b) Allowances Issued for a Future Compliance Period. A CA GHG Allowance or an allowance approved pursuant to subarticle 12 issued from an allowance budget year within a future compliance period may be held by an entity registered pursuant to section 95830.

(c) Expiration of Compliance Instruments. A California compliance instrument does not expire and is not retired in the tracking system until:

(1) It is surrendered by a covered entity or opt-in covered entity and retired by the Executive Officer;

(2) An entity voluntarily submits the instrument to the Executive Officer for retirement; or

(3) The instrument is retired by an approved external GHG emissions trading system to which the Cap-and-Trade Program is linked pursuant to subarticle 12.

(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 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.

Subarticle 12: Linkage to External Greenhouse Gas Emissions Trading Systems

§ 95940. General Requirements.

A compliance instrument issued by an external greenhouse gas emissions trading system (GHG ETS) may be used to meet the requirements of this Article if the external GHG ETS and the compliance instrument have been approved pursuant to this section and section 95941.

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.

§ 95941. Procedures for Approval of External GHG ETS.

The Board may approve a linkage with an external GHG ETS after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code sections 11340 et seq.). Provisions set forth in this Article shall specify which compliance instruments issued by a linked GHG ETS may be used to meet a compliance obligation under this Article.

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.

§ 95942. Approval of Compliance Instruments from External GHG ETS.

(a) Once a linkage is approved, a compliance instrument issued by the approved external GHG ETS, as specified in this section, may be used to meet a compliance obligation under this Article.

(b) An allowance issued by an approved external GHG ETS and specified in this section is not subject to the quantitative usage limit specified in section 95854.

(c) An offset credit or sector-based credit issued by an external GHG ETS is subject to the quantitative usage limit specified in section 95854, when used to meet a compliance obligation under this Article.

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.

§ 95943. Reserved for Linkage.

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.

An Offset Project Operator or Authorized Project Designee must ensure the requirements for ARB offset credits and registry offset credits are met as follows:

(a) A registry offset credit must:

(1) Represent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable;

(2) Result from the use of a Compliance Offset Protocol that meets the requirements of section 95972 and is adopted by the Board pursuant to section 95971;

(3) Result from an offset project that meets the requirements specified in section 95973;

(4) Result from an offset project that is listed pursuant to section 95975;

(5) Result from an offset project that follows the monitoring, reporting and record retention requirements pursuant to section 95976;

(6) Result from an offset project that is verified pursuant to sections 95977 through 95978; and

(7) Be issued pursuant to section 95980.1 by an Offset Project Registry approved pursuant to section 95986.

(b) An ARB offset credit must meet the requirements in sections 95970(a)(1) through (a)(6) and:

(1) Be issued pursuant to section 95981.1;

(2) Be registered pursuant to section 95982; and

(3) When used for compliance under this article, be subject to the quantitative usage limit pursuant to section 95854.

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.

(a) The Board shall provide public notice of and opportunity for public comment prior to approving any Compliance Offset Protocols, including updates or modifications to existing Compliance Offset Protocols.

(b) All Compliance Offset Protocols shall be reviewed and periodically revised if needed.

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.

(a) To be approved by the Board, a Compliance Offset Protocol must:

(1) Accurately determine the extent to which GHG emission reductions and GHG removal enhancements are achieved by the offset project type;

(2) Establish data collection and monitoring procedures relevant to the type of GHG emissions sources, GHG sinks, and GHG reservoirs for that offset project type;

(3) Establish a project baseline that reflects a conservative estimate of business-as-usual performance or practices for the offset project type;

(4) Account for activity-shifting leakage and market-shifting leakage for the offset project type, unless the Compliance Offset Protocol stipulates eligibility conditions for use of the Compliance Offset Protocol that eliminate the risk of activity-shifting and/or market-shifting leakage;

(5) Account for any uncertainty in quantification factors for the offset project type;

(6) Ensure GHG emission reductions and GHG removal enhancements are permanent;

(7) Include a mechanism to ensure permanence of GHG removal enhancements for sequestration offset project types;

(8) Establish the length of the crediting period pursuant to section 95972(b) for the relevant offset project type; and

(9) Establish the eligibility and additionality of projects using standard criteria, and quantify GHG reductions and GHG removal enhancements using standardized baseline assumptions, emission factors, and monitoring methods.

(b) Crediting Periods. The crediting period for a non-sequestration offset project must be no less than 7 years and no greater than 10 years, unless specified otherwise in a Compliance Offset Protocol. The crediting period for a sequestration offset project must be no less than 10 years and no greater than 30 years.

(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 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 [DATE];
2. Compliance Offset Protocol Livestock Projects, incorporated by reference [DATE];
3. Compliance Offset Protocol Urban Forest Projects, incorporated by reference [DATE]; and
4. Compliance Offset Protocol U.S. Forest Projects, incorporated by reference [DATE].

(3) Is located in the United States or its Territories, Canada, or Mexico.

(b) Local, Regional, and National 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.

(c) Early Action Offset Project Commencement Date. Offset projects that transition to Compliance Offset Protocols pursuant to section 95990(k) may have an Offset Project Commencement date before December 31, 2006.

(d) Any Offset Project Operator or Authorized Project Designee seeking to list an offset project situated on any of the following categories of land must demonstrate the existence of a limited waiver of sovereign immunity between ARB and the governing body of the Tribe entered into pursuant to section 95975(l):

(1) Land that is owned by, or subject to, an ownership or possessory interest of the Tribe;

(2) Land that is "Indian lands" of the 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.

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:

(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 the requirements of sections 95975, 95976, 95977, 95977.1, 95977.2, 95981, 95981.1, 95983, and sections 95985, and 95990, where specifically identified.

(b) Modifications to Authorized Project Designee and Activities. An Offset Project Operator may modify or change an Authorized Project Designee, or any other third party authorized pursuant to section 95974(a)(1) for a listed offset project once within each calendar year after the offset project has been listed by ARB or an Offset Project Registry by submitting a request, in writing, to ARB or an 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.

§ 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, 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.

(b) If the offset project is not listed by ARB, it must be listed by an Offset Project Registry approved pursuant to section 95986.

(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 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 be provided to an Offset Project Registry with the listing information 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, [DATE];

(2) Compliance Offset Protocol Livestock Projects, [DATE];

(3) Compliance Offset Protocol Urban Forest Projects, [DATE]; and

(4) Compliance Offset Protocol U.S. Forest Projects, [DATE].

(f) 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 determined that the information submitted pursuant to section 95975(e) is incomplete, the Offset Project Operator or Authorized Project Designee will be notified within 30 calendar days by ARB or an Offset Project Registry.

(g) 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 to ARB or an Offset Project Registry pursuant to section 95976.

(h) 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 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.

(i) 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.

(j) 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 against 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.

(k) 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).

(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.

(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.

(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.

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.

(a) General Requirements for Monitoring Equipment for Offset Projects. The Offset Project Operator or Authorized Project Designee must employ the procedures in the Compliance Offset Protocol for monitoring measurements and project performance for offset projects. All required monitoring equipment must be maintained and calibrated in a manner and at a frequency required by the equipment manufacturer, unless otherwise specified in the applicable Compliance Offset Protocol. All modeling, monitoring, sampling, or testing procedures must be conducted in a manner consistent with the applicable procedure.

(b) The Offset Project Operator or Authorized Project Designee must use the missing data methods as provided in a Compliance Offset Protocol for that offset project type, if provided and applicable.

(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, [DATE];

(2) Compliance Offset Protocol Livestock Projects, [DATE];

(3) Compliance Offset Protocol Urban Forest Projects, [DATE]; and

(4) Compliance Offset Protocol U.S. Forest 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. 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. 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, [DATE];

(2) Compliance Offset Protocol Livestock Projects, [DATE];

(3) Compliance Offset Protocol Urban Forest Projects, [DATE]; and

(4) Compliance Offset Protocol U.S. Forest Projects, [DATE].

(5) 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 approved protocol] and all information required to be submitted to ARB in the Offset Project Data Report is true, accurate, and complete."

This attestation may be provided to an Offset Project Registry with the Offset Project Data Report but must be provided to ARB when the requirements in section 95981(b) apply.

(6) All Offset Project Data Reports must be submitted within four months after the conclusion of each Reporting Period.

(7) 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.

(e) Requirements for Record Retention for Offset Projects. An Offset Project Operator or Authorized Project Designee must meet the following requirements:

(1) The Offset Project Operator or Authorized Project Designee must retain the following documents:

(A) All information submitted as part of the Offset Project Data Report;

(B) Documentation of the offset project boundary, including a list of all GHG emissions sources, GHG sinks, and GHG reservoirs included in the offset project boundary and the project baseline, and the calculation of the project baseline, project emissions, GHG emission reductions, and GHG removal enhancements;

(C) Fuel use and any other underlying measured or sampled data used to calculate project baseline emissions, GHG emission reductions, and GHG removal enhancements for each source, categorized by process and fuel, or material type;

(D) Documentation of the process for collecting fuel use or any other underlying measured or sampled data for the offset project and its GHG emissions sources, GHG sinks, and GHG reservoirs for quantifying project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(E) Documentation of all project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(F) All point of origin and chain of custody documents required by a Compliance Offset Protocol, if applicable;

(G) All chemical analyses, results, and testing-related documentation for material and sources used for inputs to project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(H) All model inputs or assumptions used for quantifying project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(I) Any data used to assess the accuracy of project baseline emissions, GHG emission reductions, and GHG removal

enhancements from each offset project GHG emissions source, GHG sink, and GHG reservoir, categorized by process;

(J) Quality assurance and quality control information including information regarding any measurement gaps, missing data substitution, calibrations or maintenance records for monitoring equipment, or models providing data for calculating project baseline emissions, project emissions, GHG emission reductions, and GHG removal enhancements;

(K) A detailed technical description of any offset project continuous measurement/monitoring system, including documentation of any findings and approvals by federal, state, and local agencies;

(L) Raw and aggregated data from any measurement system;

(M) Documentation of any changes over time and the log book on tests, down-times, calibrations, servicing, and maintenance for any measurement/monitoring equipment providing data for project baseline calculations, project emissions, GHG emission reductions, and GHG removal enhancements;

(N) For sequestration offset projects, documentation of inventory methodologies and sampling procedures including all calculation methodologies and equations used, and any data related to plot sampling; and

(O) Any other documentation or data required to be retained by a Compliance Offset Protocol, if applicable.

(2) Documents listed in section 95976(e)(1) associated with the preparation of an Offset Project Data Report shall be retained in paper, electronic, or other usable format for a minimum of 15 years following the issuance of ARB offset credits related to that Offset Project Data Report. All other documents shall be retained in paper, electronic, or other usable format for a minimum of 15 years.

(3) The documents retained pursuant to this section must be sufficient to allow for the verification of each Offset Project Data Report.

(4) Upon request by ARB or an Offset Project Registry, the Offset Project Operator or Authorized Project Designee must provide to ARB or an Offset Project Registry all documents pursuant to this section, including data used to develop an Offset Project Data Report within 10 calendar days of the request.

(f) General Procedure for Interim Gas or Fuel Analytical and Monitoring Equipment Data Collection. This section only applies if a Compliance Offset Protocol does not already include methods for collecting or accounting for data in the event of missing data due to an unforeseen breakdown of gas or fuel analytical monitoring data equipment.

(1) In the event of an unforeseen breakdown of offset project data monitoring equipment and gas or fuel flow monitoring devices required for the GHG emission reductions and GHG removal enhancement estimation, ARB may authorize an Offset Project Operator or Authorized Project Designee to use an interim data collection procedure if ARB determines that the Offset Project Operator or Authorized Project Designee has satisfactorily demonstrated that:

(A) The breakdown may result in a loss of more than 20 percent of the source's gas or fuel data for the year covered by an Offset Project Data Report;

(B) The gas or fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting the offset project operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

(D) The request was submitted within 30 calendar days of the breakdown of the gas or fuel analytical data monitoring equipment.

(2) An Offset Project Operator or Authorized Project Designee seeking approval of an interim data collection procedure must, within 30 calendar days of the monitoring equipment breakdown, submit a written request to ARB that includes all of the following:

(A) The proposed start date and end date of the interim procedure;

(B) A detailed description of what data are affected by the breakdown;

(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the Offset Project Operator's or Authorized Project Designee's usual equipment-based method; and

(D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) ARB may limit the duration of the interim data collection procedure or include other conditions for approval.

(4) Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with a Compliance Offset Protocol. When approving an interim data collection procedure, ARB shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible offset material misstatement under section 95977.1(b)(3)(Q) of this article.

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.

(a) General Requirements. An Offset Project Operator or Authorized Project Designee must obtain the services of an ARB-accredited verification body for the purposes of verifying Offset Project Data Reports submitted under this article.

(b) Schedule for Verification of Non-Sequestration Offset Projects. The verification of GHG emission reductions for non-sequestration offset projects must be performed annually 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.

(c) Schedule for Verification of Sequestration Offset Projects. The verification of GHG emission reductions and GHG removal enhancements for sequestration offset projects must be performed 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 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 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.

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 verified by the same verification body or verifier(s). 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 have been verified by a different verification body or verifier(s) before the previous verification body is selected again. The six year rotation requirement is applied between the Offset Project Operator or Authorized Project Designee and the verification body or verifier(s) on an offset project basis.

(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 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 days after the Notice for Offset Verification Services is received by ARB or the Offset Project Registry, or earlier, if approved by ARB in writing. The Notice for 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, the verification body must notify ARB and the Offset Project Registry by submitting an updated conflict of interest self-evaluation form as soon as the change is made, but, at least five days prior to the start of offset verification services. 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 must be resubmitted to ARB or the Offset Project Registry, as applicable.

(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:

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. Such information shall include:

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.

(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 each offset project location for which 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 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 of an offset project. During the site visit, the offset verification team member(s) must conduct the following:

1. During the initial site visit the offset verification team members must:

a. Assess offset project eligibility and 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, and monitor the offset project conforms to the requirements of the applicable Compliance Offset Protocol.

2. During the initial 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 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 GHG emissions, GHG reductions, and GHG removal enhancement calculations;
   e. Data reporting;
   f. Chain of custody requirements; and
   g. 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 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 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 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, 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. 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, 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 relative to the project baseline 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:

$$Percenterror = \sum \frac{[Discrepancies + Omissions + Misreporting]\ x\ 100\%}{Total\ reported emissions}$$

Where:

"Discrepancies" means any differences between the reported GHG emissions, project 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.

"Omissions" means any GHG emissions, 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.

"Misreporting" means duplicative, incomplete, or other GHG 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.

"Total reported emissions" means annual reported net GHG reductions and GHG removal enhancements relative to the project baseline 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 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. 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, 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) 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 contained within the Offset Project Data Report and that these nonconformances 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.

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 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 before 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.

§ 95977.2. Additional Project Specific Requirements for Offset Verification Services.

In addition to meeting the offset verification requirements in sections 95977 and 95977.1, Offset Project Operators or Authorized Project Designees must ensure the GHG emission reductions and GHG removal enhancements resulting from an offset project meet any additional verification requirements in the Compliance Offset Protocol, if applicable, for an offset project of that type.

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.

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.

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 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 Authorized Project Designees.

(b) The potential for a conflict of interest must be deemed to be high where:

(1) The verification body and Offset Project Operator or Authorized Project Designee share any senior management staff or board of directors membership, or any of the senior management staff of the Offset Project Operator or Authorized Project Designee 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 Authorized Project Designee 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 Authorized Project Designee;

(G) Preparing or producing GHG-related manuals, handbooks, or procedures specifically for the Offset Project Operator or Authorized Project Designee;

(H) Appraisal services of carbon or GHG liabilities or assets;

(I) Brokering in, advising on, or assisting in any way in carbon or GHG-related markets;

(J) Directly managing any health, environment or safety functions for the Offset Project Operator or Authorized Project Designee;

(K) Bookkeeping or other services related to the accounting records or financial statements;

(L) Any service related to information systems, including 14001 certification, unless those systems will not be reviewed as part of the offset verification process;

(M) Appraisal and valuation services, both tangible and intangible;

(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the information reviewed in formulating the Offset Verification Statement will not be reviewed as part of the offset verification services;

(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(P) Any internal audit service that has been outsourced by the Offset Project Operator or Authorized Project Designee that relates to the Offset Project Operator's or Authorized Project

Designee's internal accounting controls, financial systems, or financial statements, unless the systems and data reviewed during those services, as well as the result of those services will not be part of the offset verification process;

(Q) Acting as a broker-dealer (registered or unregistered), promoter, or underwriter on behalf of the Offset Project Operator or Authorized Project Designee;

(R) Any legal services; and

(S) Expert services to the Offset Project Operator or Authorized Project Designee or a legal representative for the purpose of advocating the Offset Project Operator's or Authorized Project Designee's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related 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 Authorized Project Designee 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 Authorized

Project Designee, except within the time periods in which the Offset Project Operator or Authorized Project Designee 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 Authorized Project Designee 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 Authorized Project Designee, 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 Authorized Project Designee 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 Authorized Project Designee, and ARB or 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 Authorized Project Designee for which it will perform offset verification services. 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 Authorized Project Designee, 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 Authorized Project Designee either within or outside California during the previous three 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 Authorized Project Designee 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 Authorized Project Designee including:

1. Instances when any member of the offset verification team has performed or intends to perform work for the Offset Project Operator or Authorized Project Designee;
2. Identification of whether work is currently being performed for the Offset Project Operator or Authorized Project Designee, and if so, the nature of the work;
3. How much work was performed for the Offset Project Operator or Authorized Project Designee in the last three 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 Authorized Project Designee 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 Authorized Project Designee or related entities in the last three 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 Authorized Project Designee, and a description of any instances of personal or family relationships with management or employees of the Offset Project Operator or Authorized Project Designee that potentially represent a conflict of interest;

(E) Identification of any other circumstances known to the verification body, or Offset Project Operator or Authorized Project Designee 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) 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 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 Authorized Project Designee for which the verification body has provided offset verification services, the verification body must notify ARB or 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 conflict using the criteria in sections 95979(a) through (d), if the Offset Project Operator or Authorized Project Designee must re-verify their Offset Project Data Report, and if accreditation revocation is warranted by ARB.

(3) The verification body must notify ARB or 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 Authorized Project Designee 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 Authorized Project Designee, 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 Authorized Project designee 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.

(g) 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 Developer or Authorized Project Designee for which it intends to provide 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.

§ 95980. Issuance of Registry Offset Credits.

(a) One registry offset credit, which represents one metric ton of CO_2e for a direct GHG emission reduction or direct GHG removal enhancement, will be issued pursuant to section 95980.1 only if:

(1) An Offset Project Registry has listed the offset project pursuant to section 95975;

(2) The GHG emission reductions or GHG removal enhancements were issued a Positive Offset or Qualified Positive Offset Verification Statement pursuant to section 95977.1 and 95977.2; and

(3) 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 would be issued.

(b) An Offset Project Registry will determine whether the GHG emission reductions and GHG removal enhancements meet the requirements of section 95980(a), the information submitted pursuant to section 95980(a) is complete, and the Positive Offset or Qualified Positive Offset Verification Statement meets the requirements of 95977, 95977.1, and 95977.2 within 45 calendar days of receiving it.

(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. An early action offset project that transitions pursuant to section 95990(k) will begin its initial crediting period pursuant to section 95990(k)(2).

(d) Determination for Timing and Duration of Renewed Crediting for Offset Projects Submitted through an Offset Project Registry. A renewed crediting period will begin the day after the conclusion of the prior crediting 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.

§ 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 section 95980(a) 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), no later than 15

calendar days after an Offset Project Registry makes a determination pursuant to section 95980(b).

(b) Change of Listing Status at the Offset Project Registry. When an Offset Project Registry issues a registry offset credit for an offset project, the listing status for that offset project will be changed to either "Active Registry Project" or "Active Registry Renewal" at the Offset Project Registry and ARB.

(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) 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) 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 section 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 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) Offset Project Data Reports submitted to an Offset Project Registry pursuant to section 95976(d); and

(4) Offset Verification Statements submitted pursuant to section 95977.1(b)(3)(R)(4.)(b.).

(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 95977, 95977.1, and 95977.2 within 45 calendar days of receiving it.

(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 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. An early action offset project that transitions pursuant to section 95990(k) will begin its initial crediting period pursuant to section 95990(k)(2).

(f) Determination for Timing and Duration of Renewed Crediting for Offset Projects Submitted Through ARB. A renewed crediting period will begin the day after the conclusion of the prior crediting 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.

§ 95981.1 Process for Issuance of ARB Offset Credits.

(a) ARB will issue an ARB offset credit that meets the requirements of section 95981(a) 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), no later than 15 calendar days after ARB makes a determination pursuant to section 95981(c).

(b) Change of Listing Status at ARB. When ARB issues an ARB offset credit for an offset project, the listing status for that offset project will be changed from "Active Registry Project" to "Active ARB Project" or "Active Registry Renewal" to "Active ARB Renewal" at the Offset Project Registry and ARB.

(c) Notice of Determination of Issuance of ARB Offset Credits. Not later than 15 calendar days after ARB issues an ARB offset credit, ARB 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. 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 95974(a)(1) within 15 calendar days of its determination pursuant to section 95981(c) if the information in section 95981(b) and (c) 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 that meet the requirements of section 95981.

(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.

(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 by the Offset Project Operator pursuant to section 95974(a)(1), 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.

An ARB offset credit will be registered by:

(a) Creating a unique ARB serial number; and

(b) Transferring this serial number to the Holding Account of the listed Offset Project Operator, Authorized Project Designee, or another third party as provided in section 95974(a)(1) 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.

(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.

(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.

(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.

(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.

(A) Notification by ARB will occur after the verified estimate of carbon stocks 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.

(B) If the forest owner does not submit valid ARB offset credits or other approved compliance instruments to ARB within six months of notification by ARB, ARB will retire a quantity of ARB offset credits 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) 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, [DATE]. This provision only applies to ARB offset credits that have been issued to the offset project.

(A) ARB will notify the forest owner of retirement within 10 calendar days.

(B) 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 retired by ARB from the Forest Buffer Account within six months of ARB's retirement.

(C) If the forest owner does not submit valid ARB offset credits or other approved compliance instruments to ARB within six months of ARB's retirement, 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 offset credits issued to the offset project pursuant to section 95990(i) 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 section 95974(a)(1), 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.

(b) An ARB offset credit may only be used:

(1) To meet a compliance obligation under this article, except if used by a covered entity in a program approved for linkage pursuant to subarticle 12; or

(2) By a Voluntarily Associated Entity for purposes of voluntary retirement.

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.

(a) An ARB offset credit issued under this article will remain valid unless invalidated pursuant to this section.

(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 unless one of the following requirements is met;

(A) An offset project developed under Compliance Offset Protocol Ozone Depleting Substances Projects, [DATE], 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

(B) An offset project developed under the protocols listed below, 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. This provision applies if an offset project is developed under one of the following Compliance Offset Protocols;

1. Compliance Offset Protocol Livestock Projects, [DATE];
2. Compliance Offset Protocol Urban Forest Projects, [DATE]; and
3. Compliance Offset Protocol U.S. Forest 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 percent;

(A) If ARB finds that there has been an overstatement by more than five 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:

$$\text{If: } I_{ARBOC} > R_{OPDR} \text{ X } 1.05$$

$$\text{Then: } O_R = I_{ARBOC} - R_{OPDR}$$

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.

(d) Suspension of Transfers. When ARB makes an initial determination pursuant to section 95985(c) it will immediately block any transfers of ARB offset credits for the applicable Offset Project Data Report. Once ARB makes a final determination pursuant to section 95985(f) the block on transfers for any valid ARB offset credits will be cancelled.

(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 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).

(f) Final Determination and Process of Invalidation. ARB will notify the parties identified in section 95985(e) of its initial determination pursuant to section 95985(c), and provide each party an opportunity to submit additional information to ARB prior to making its final determination, as follows:

(1) ARB will include the reason for its initial determination in its notification to the parties identified in section 95985(e).

(2) After notification the parties identified in section 95985(e) will have 25 calendar days to provide any additional information to ARB.

(3) ARB may request any information as needed in addition to the information provided under this section.

(4) The Executive Officer will have 30 calendar days after all information is submitted under this section to make a final determination that one or more conditions listed pursuant to section 95985(c) has occurred and whether to invalidate ARB offset credits.

(A) The parties identified pursuant to section 95985(e) will be notified of ARB's final determination of invalidation pursuant to this section.

(B) Any approved program for linkage pursuant to subarticle 12 will be notified of the invalidation at the time of ARB's final determination pursuant to this section.

(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 ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to section 95985(g)(1)(A) and remove 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 in the Retirement Account from a non-sequestration offset project 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 credits and will notify the Offset Project Operator that they must replace them.

2. 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 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 ARB offset credits issued under the applicable Offset Project Data Report in the amount calculated pursuant to section 95985(h)(1)(A) and invalidate those serial numbers.

(E) The parties identified pursuant to section 95985(e) 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 non-sequestration offset project 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. 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 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 Forest Offset Projects.

(1) If an ARB offset credit in the Retirement Account from a forest offset project is determined to be invalid pursuant to section 95985(f) for only the circumstance listed in section 95985(c)(1):

(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 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 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 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 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) 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 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.

(j) Nothing in this section shall limit the authority of the State of California from pursuing enforcement action against any parties in violation of this article.

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.

(a) The approval requirements specified in this subarticle apply to all Offset Project Registries that will operate to provide registry services under this article.

(b) The Executive Officer may approve Offset Project Registries that meet the requirements specified in this section.

(c) The Offset Project Registry must 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; 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.

(e) The Offset Project Registry must continue to maintain the professional liability insurance required in section 95986(c) while it provides registry services to Offset Project Operators or Authorized Project Designees who are implementing offset projects using Compliance Offset Protocols.

(f) If any information submitted pursuant to sections 95986(c) through (e) changes after the approval of an Offset Project Registry, the Offset Project Registry must notify the Executive Officer within 30 calendar days and provide updated information consistent with that required in sections 95986(c) through (e).

(g) The Offset Project Registry must attest, in writing, to ARB as follows:

(1) "As the authorized representative for this Offset Project Registry, I understand that the Offset Project Registry is voluntarily participating in the California Cap-and-Trade Program under title 17, article 5, and the Offset Project Registry is now subject to all regulatory requirements and enforcement mechanisms of this program.";

(2) "All information generated and submitted to ARB by the Offset Project Registry related to an offset project that uses a Compliance Offset Protocol will be true, accurate, and complete.";

(3) "All information provided to ARB as part of an ARB audit of the Offset Project Registry will be true, accurate, and complete.";

(4) "All registry services provided will be in accordance to the requirements of section 95987.";

(5) "The Offset Project Registry is committed to participating in all ARB training related to ARB's compliance offset program or Compliance Offset Protocols."; and

(6) The authorized representative of the Offset Project Registry must attest in writing, to ARB: "I certify under penalty of perjury under the laws of the State of California I have authority to represent the Offset Project Registry and all information provided as part of this application is true, accurate, and complete.".

(h) At least two of the management staff at the Offset Project Registry must take ARB provided training on ARB's compliance offset program and pass an examination upon completion of training.

(i) The Offset Project Registry must have staff members who have collectively completed ARB training and passed an examination upon completion of training in all Compliance Offset Protocols.

(j) The Offset Project Registry must have experience in, and requirements for, staff oversight of the offset project review, listing, and registry offset credit issuance process.

(k) ARB Approval.

(1) Within 60 calendar days of receiving an application for approval as an Offset Project Registry and completion by all management staff of the training required in section 95986(h), the Executive Officer will inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) The applicant may be allowed to submit additional supporting documentation before a decision is made by the Executive Officer.

(3) Within 60 calendar days following completion of the application process, the Executive Officer shall approve an Offset Project Registry if evidence of qualification submitted by the applicant has been found to meet the requirements of section 95986 and issue an Executive Order to that effect.

(4) The Executive Officer and the applicant may mutually agree, in writing, to longer time periods than those specified in subsections 95986(k)(1) and 95986(k)(3).

(5) The Executive Officer approval for an Offset Project Registry is valid for a period of 10 years, whereupon the applicant may re-apply. At the time of re-application, the Offset Project Registry must:

(A) Demonstrate it consistently met all of the requirements in section 95986;

(B) Pass a performance review, which, at a minimum shows the Offset Project Registry consistently:

1. Demonstrates knowledge of the ARB compliance offset program and Compliance Offset Protocols;
2. Meets all regulatory deadlines; and
3. Provides registry services in accordance with the requirements of this article; and

(C) Not have been subject to enforcement action under this article.

(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 is necessary to provide time for re-submission of information to the new Offset Project Registry or 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.

§ 95987. Offset Project Registry Requirements.

(a) The Offset Project Registry shall use Compliance Offset Protocols approved pursuant to section 95971 to determine whether an offset project may be listed with the Offset Project Registry for issuance of registry offset credits. The Offset Project Registry may list projects under non-Compliance Offset Protocols, but must make it clear any GHG emission reductions and GHG removal enhancements achieved under those protocols are not eligible to be issued registry offset credits or ARB offset credits.

(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:

(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) 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.

(c) Conflict of Interest Review by Offset Project Registries. The Offset Project Registry must apply the conflict of interest requirements in section 95979 when making a conflict of interest determination for a verification body proposing to conduct offset verification services under sections 95977.1 and 95977.2. The Offset Project Registry must review and make sure the conflict of interest submittal in section 95979(e) is complete. When an Offset Project Operator or Authorized Project Designee submits its information pursuant to section 95981(b) to ARB, the Offset Project Registry must provide ARB with the information and attestation identified in section 95979(e) within 15 calendar days.

(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.

(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 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 lead to the Offset Project Registry to provide guidance 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).

(f) The Offset Project Registry must review each detailed verification report provided in section 95977.1(b)(3)(R)(4.)(a.) for completeness and accuracy and to ensure it meets the requirements of section 95977.1(b)(3)(R)(4.)(a.) before accepting the associated Offset Verification Statement for the Offset Project Data Report and issuing registry offset credits.

(g) The Offset Project Registry must provide all information in its possession, custody, or control related to a listed offset project under a Compliance Offset Protocol within 10 calendar days of request by ARB.

(h) The Offset Project Registry must make its staff and all information related to listed offset projects under Compliance Offset Protocols by the Offset Project Registry available to ARB during any audits or oversight activities initiated by ARB to ensure the requirements in section 95987 are being carried out as required by this article.

(i) The Offset Project Registry must remove or cancel any registry offset credits issued for an offset project using a Compliance Offset Protocol, such that the registry offset credits are no longer available for transaction on the Offset Project Registry system, once notified by ARB that the offset project is eligible to be issued ARB offset credits.

(j) The Offset Project Registry must provide an annual report by January 31 of the previous year's offset projects that are listed using a Compliance Offset Protocol. The report must contain the name of the offset project, type of offset project and applicable Compliance Offset Protocol, name of Offset Project Operator or Authorized Project Designee, location of offset project, status of offset project, associated verification body, crediting period, amount of any registry offset credits issued to date, amount of any registry offset credits retired or cancelled for the offset project by the Offset Project Registry to date.

(k) The Offset Project Registry may choose to offer insurance or other products to cover the risk of invalidation of ARB offset credits, but purchase or use of the insurance or other invalidation risk mechanisms will be optional for all entities involved with registry offset credits and ARB offset credit transactions.

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.

§95988. Record Retention Requirements for Offset Project Registries.

All information submitted, and correspondence related to, listed offset projects under Compliance Offset Protocols by the Offset Project Registry must be maintained by the Offset Project Registry for a minimum of 15 years.

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.

(a) Approval of Early Action Offset Programs. To qualify as an Early Action Offset Program, either the Executive Officer shall issue an Executive Order pursuant to section 95986(k) or the program must demonstrate to ARB that it meets the following requirements:

(1) The program must provide documentation that it carries at least one million U.S. dollars of professional liability insurance.

(2) The program must have the following capabilities for registration and tracking of offset credits:

(A) A registration requirement for all registry participants;

(B) A system for tracking ownership and transactions of all early action offset credits it issues under the quantification methodologies listed pursuant to section 95990(c)(5) at all times; and

(C) A permanent repository of ownership information on all transactions involving all early action offset credits that have been or will be issued for any early action offset project until they are retired or cancelled.

(3) The program's primary business (or that of the designated subdivision, if the Early Action Offset Program applicant designates a subdivision to provide services as an Early Action Offset Program pursuant to this section) is operating a registry for issuing offset credits for voluntary or regulatory purposes and must meet the following business requirements:

(A) The Early Action Offset Program may not act as an Offset Project Operator, Authorized Project Designee, or offset project consultant for early action offset projects registered on its own registry system and developed under protocols approved pursuant 95990(c)(5). The Early Action Offset Program applicant may act as an offset project consultant for early action offset projects as long as these are registered with an Early Action Offset Program or an Offset Project Registry unaffiliated with the applicant;

(B) The applicant may not act as a verification body and provide offset verification services pursuant to section 95990(f);

(C) 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; and

(D) The applicant's primary incorporation or other business information and primary place of business, or the primary place of business of the designated subdivision, if the applicant designates a subdivision to be an Early Action Offset Program

pursuant to this section, must be in the United States of America.

(4) The program must agree to submit to ARB the original documentation submitted by an Offset Project Operator or Authorized Project Designee or third-party verifier regarding the early action offset project, including registration documentation, sampling plans, and Early Action Verification Reports.

(5) The program must agree to retire, and not allow for further use, any early action offset credits it issues when retired or used in any voluntary or regulatory program, including when ARB requests retirement for ARB offset credit issuance pursuant to section 95990(i).

(6) An authorized representative of the Early Action Offset Program must attest in writing, to ARB, as follows:
"I certify under penalty of perjury under the laws of the State of California the information provided in demonstrating this program meets the requirements in section 95990(a) and is true, accurate, and complete."

(b) ARB shall accept early action offset credits from early action offset projects registered with Early Action Offset Programs approved pursuant to section 95990(a), if the early action offset credits meet the criteria set forth in this section.

(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;

(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, [DATE].

(E) Reserved for additional early action offset project protocols.

(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).

(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 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).

(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 holder registers with ARB pursuant to section 95990(d) and provides ARB with the attestations required pursuant to section 95990(h)(6).

(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.

(3) 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 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 the verification body that conducted offset verification services for the early action offset project under the Early Action Offset Program.

(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 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). The desk review of all Offset Project Data Report 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. 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 of the data checks conducted by the 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, the verification body must submit the attestation in section 95990(f)(3)(D) to ARB.

(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."

(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 eligible and applicable pursuant to section 95990(c)(1) to the offset verification team to assist in offset verification services and desk review.

(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 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 should not have been issued a positive verification statement after reviewing the information submitted in section 95990(f)(5), the Offset Project Data Report must be verified and 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 Offset

verification services for each Offset Project Data Report year 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 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 pursuant to section 95990(i) subsequent offset verification services provided for additional Offset Project Data Reports for the same early action offset project will not trigger a desk review of those Offset Project Data Reports 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 that a verification body reviews 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 must be submitted to ARB before ARB issues an ARB offset credit pursuant to section 95990(i).

(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 Authorized Project Designee 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 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);

(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).

(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, the Early Action Offset Program must transfer all of the early action offset credits in 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.

   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.

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, [DATE] for each Offset Project Data Report year eligible and applicable pursuant to section 95990(c)(1).
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 be issued to the Offset Project Operator or Authorized Project Designee as follows:
   a. If the following condition applies, then ARB will issue one ARB offset credit for each early action offset credit:

$$EAOP_{Buffer} \geq EAOC_{Issue} \times RR_{COP}$$

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;

"$EAOC_{Issue}$" 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 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, [DATE];

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:

$$If: EAOP_{Buffer} < EAOC_{Issue} \times RR_{COP}$$

$$Then: ARB_{Issue} = EAOC_{Issue} - \left|(EAOC_{Issue} \times RR_{COP}) - EAOP_{Buffer}\right|$$

Where:

"ARB_{Issue}" is the total number of ARB offset credits that will be issued to the Offset Project Operator or Authorized Project Designee 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 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, [DATE];

"$EAOP_{Buffer}$" 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;

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, [DATE];

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, [DATE];

"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. 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, [DATE], the provisions in section 95983(b) and (d) apply.
6. 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, [DATE], the provisions in section 95983(c) and (d) apply.

(E) 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, [DATE]

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, [DATE] 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)(E)(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)(E)(1.).
    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)(1.).

(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 removed 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 holders of the original early action offset credits 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), 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), ARB will transfer the ARB offset credit into the Holding Account of the holder. The holder must prove ownership of the original early action offset credits, including the original serial numbers issued by the Early Action Offset Program, before ARB will transfer the ARB offset credits.

(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:

(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, [DATE];

(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, [DATE];

(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, [DATE];

(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, [DATE]. 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, [DATE] and the requirements in this article 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). 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, [DATE], 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, [DATE] 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.

(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) that were achieved in 2014. 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.

(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 from a non-sequestration project may be invalidated pursuant to sections 95985(a) through (h) and section 95985(j):

(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), 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 from a forest offset project may be invalidated pursuant to sections 95985(a) through (g) and sections 95985(i) and (j).

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.

§ 95991. Sector-Based Offset Credits.

Sector-based offset credits may be generated through reduced or avoided GHG emissions from within, or carbon removed and sequestered from the atmosphere by, a specific sector in a particular jurisdiction. The Board may consider for acceptance compliance instruments issued from sector-based offset crediting programs that meet the requirements set forth in section 95994 and originate from developing countries or from subnational jurisdictions within those developing countries, except as specified in subarticle 13.

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.

§ 95992. Procedures for Approval of Sector-Based Crediting Programs.

The Board may approve a sector-based crediting program in an eligible jurisdiction after public notice and opportunity for public comment in accordance with the Administrative Procedure Act (Government Code section 11340 et seq.). Provisions set forth in this article shall specify which compliance instruments issued by an approved sector-based crediting program may be used to meet a compliance obligation under this Article.

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.

§ 95993. Sources for Sector-Based Offset Credits.

Sector-based credits may be generated from:

(a) Reducing Emissions from Deforestation and Forest Degradation (REDD) Plans; and

(b) Reserved for other sources of sector-based credits.

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.

§ 95994. Requirements for Sector-Based Offset Crediting Programs.

(a) General Requirements for Sector-Based Crediting Programs. The Board may consider for approval a sector-based crediting program which may include the following sectoral requirements:

(1) Sector Plan. The host jurisdiction has established a plan for reducing emissions from the sector.

(2) Monitoring, Reporting, Verification, and Enforcement. The program includes a transparent system that regularly monitors, inventories, reports, verifies, and maintains accounting for emission reductions across the program's entire sector, as well as maintains enforcement capability over its reference activity producing credits.

(3) Offset Criteria. The program has requirements to ensure that offset credits generated by the program are real, additional, quantifiable, permanent, verifiable and enforceable.

(4) Sectoral Level Performance. The program includes a transparent system for determining and reporting when it meets or exceeds its crediting baseline(s), and evaluating the performance of the program's sector during each program's crediting period relative to the business as usual or other emissions reference level.

(5) Public Participation and Participatory Management Mechanism. The program has established a means for public participation and consultation in the program design process.

(6) Nested Approach. If applicable, the program includes:

(A) Offset project-specific requirements that establish methods to inventory, quantify, monitor, verify, enforce, and account for all project-level activities

(B) A system for reconciling offset project-based GHG reductions in sector-level accounting from the host jurisdiction.

(b) Sector-Specific Requirements. Pursuant to section 95996, specific sectors may have specific requirements unique to that sector.

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.

§ 95995. Quantitative Usage Limit.

Sector-based offset credits approved by ARB for compliance pursuant to section 95821(d) are subject to the quantitative usage limit specified in section 95854.

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.

§ 95996. Reserved for Sector-Specific Requirements.

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.

§ 95997. Reserved for Approved Sector-Based Crediting Programs.

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 15: Enforcement and Penalties

§ 96010. Jurisdiction.

Any of the following actions shall conclusively establish a person's consent to be subject to the jurisdiction of the State of California, including the administrative authority of ARB and the jurisdiction of the Superior Courts of the State of California:

(a) Registration with ARB pursuant to subarticle 5;

(b) The purchase or holding of a compliance instrument issued by ARB;

(c) Receipt of compensation of any kind, including sales proceeds and commissions, from any transfers of allowances or offset credits issued by ARB pursuant to subarticle 13 or recognized by ARB pursuant to subarticle 14; or

(d) Verification of an offset credit to be 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.

§ 96011. Authority to Suspend, Revoke, or Modify.

(a) The Executive Officer may suspend, revoke, or place restrictions on the Holding Account of a voluntarily associated entity determined to be in violation of any provision of this article.

(b) The Executive Officer may place restrictions on a Holding Account of a covered entity or an opt-in covered entity determined to be in violation of any provision of this article or of article 2 of this subchapter.

(c) The Executive Officer may suspend, revoke, or modify any Executive Order issued under this article or under article 2 of this subchapter, including an order accrediting a verifier, for a violation of any provision of this article.

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.

§ 96012. Injunctions.

Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

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.

§ 96013. Penalties.

Penalties may be assessed pursuant to Health and Safety Code section 38580 for any violation of this article as specified in section 96014. In determining any penalty amount, ARB shall consider all relevant circumstances, including the criteria in Health and Safety Code section 42403(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.

§ 96014. Violations.

(a) If an entity fails to surrender a sufficient number of compliance instruments to meet its compliance obligation as specified in sections 95856 or 95857, and the procedures in 95857(c) have been exhausted, there is a separate violation of this article for each required compliance instrument that has not been surrendered, or otherwise obtained by the Executive Officer under 95857(c).

(b) A separate violation accrues every 45 days after the end of the Untimely Surrender Period pursuant to section 95857 for each required compliance instrument that has not been surrendered.

(c) It is a violation to submit any record, information or report required by this article that:

(1) Falsifies, conceals, or covers up by any trick, scheme or device a material fact;

(2) Makes any false, fictitious or fraudulent statement or representation;

(3) Makes or uses any false writing or document knowing the same to contain any false, fictitious or fraudulent statement or entry; or

(4) Omits material facts from a submittal or record.

(5) A fact is material if it could probably influence a decision by the Executive Officer, the Board, or the Board's staff.

(d) The violations stated in section 96014(c) are additional to violations of any obligations of any entity subject to this regulation under other provisions of this article requiring submissions to ARB to be true, accurate and complete.

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

§ 96020. Severability, Effect of Judicial Order.

Each provision of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

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.

§ 96021. Confidentiality.

(a) Emissions data submitted to ARB under this article is public information and shall not be designated as confidential.

(b) Any entity submitting information to the Executive Officer pursuant to this subarticle may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Record Act (Government Code, section 6250 et seq.). All such requests

for confidentiality shall be handled in accordance with the procedures specified in California Code of Regulations, title 17, sections 91000 to 91022.

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.

§ 96022. Jurisdiction of California.

Any party that participates in the Cap-and-Trade Program is subject to the jurisdiction of the State of California.

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.

§ 96023. Reserved Provisions.

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.

October 2011

California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol Ozone Depleting Substances Projects

Destruction of U.S. Ozone Depleting Substances Banks

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

A/C	Air conditioning
AHRI	Air-Conditioning, Heating and Refrigeration Institute
CAA	Clean Air Act
CAR	Climate Action Reserve
CEMS	Continuous emissions monitoring system
CFC	Chlorofluorocarbons
CH_4	Methane
CO_2	Carbon dioxide
CPT	Comprehensive Performance Test
DOT	U.S. Department of Transportation
DRE	Destruction and removal efficiency
EPA	United States Environmental Protection Agency
GWP	Global warming potential
HBFC	Hydrobromofluorocarbons
HCFC	Hydrochlorofluorocarbons
HFC	Hydrofluorocarbons
HWC	Hazardous waste combustor
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NIST	National Institute of Standards and Technology
ODS	Ozone depleting substances
PU	Polyurethane
RCRA	Resource Conservation and Recovery Act

Regulation	Cap-and-Trade Regulation, title 17, California Code of Regulations, sections 95800 et seq.
SSR	GHG Sources, GHG Sinks, and GHG Reservoirs
TEAP	Technology & Economic Assessment Panel

1 Introduction

The Compliance Offset Protocol Ozone Depleting Substances Projects provides methods to quantify and report greenhouse gas (GHG) emission reductions associated with the destruction of high global warming potential ozone depleting substances (ODS) sourced from and destroyed within the U.S. that would have otherwise been released to the atmosphere. This project category includes ODS used in foam blowing agent and refrigerant applications. All destroyed ODS must be fully documented, chemically analyzed, and destroyed at a qualifying facility to be eligible for crediting under this protocol. All ODS must originate in the United States. The protocol is built off of The Climate Action Reserve's U.S. Ozone Depleting Substances Project Protocol Version 1.0[1] and includes the information provided in the Errata and Clarification[2].

ODS Offset Project Operators or Authorized Project Designees must use this protocol to quantify and report GHG reductions. The protocol provides eligibility rules, methods to quantify GHG reductions, offset project-monitoring instructions, and procedures for preparing Offset Project Data Reports. Additionally, all offset projects must submit to annual, independent verification by ARB-accredited verification bodies. Requirements for verification bodies to verify Offset Project Data Reports are provided in the Cap and Trade Regulation (Regulation).

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification of GHG emission reductions associated with an ODS destruction project. The protocol is comprised of both quantification methodologies and regulatory program requirements to develop an ODS project and generate ARB or registry offset credits.

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[3], 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 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.

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[1] Climate Action Reserve (2010) U.S. Ozone Depleting Substances Project Protocol Version 1.0. February 3, 2010. http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

[2] Climate Action Reserve (2010) U.S. Ozone Depleting Substances Project Protocol Errata and Clarifications. May 7, 2010. http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

[3] Health and Safety Code section 38571.

2 The GHG Reduction Project

2.1 Background

The term "ozone depleting substances" (ODS) refers to a large group of chemicals known to destroy the stratospheric ozone layer when released into the atmosphere. ODS were historically used in a wide variety of applications including refrigerants, foam blowing agents, solvents, and fire suppressants. In addition to their potency as ozone depleting substances, the ODS addressed by this protocol also exhibit high global warming potentials (GWP). The GWP of these ODS range from several hundred to several thousand times that of carbon dioxide (see Table 5.1).

2.2 Offset Project Definition – Quantification Methodology

For the purposes of this protocol, an offset project is defined as any set of activities undertaken by a single Offset Project Operator or Authorized Project Designee resulting in the destruction of eligible ODS at a single qualifying destruction facility over a 12-month period. Destruction may take place under one or more Certificates of Destruction. Each Certificate of Destruction must document the ODS destroyed. The ODS destroyed may come from a single origin (e.g., one supermarket) or from numerous sources. However, the entire quantity of eligible ODS destroyed must be documented on one or more Certificates of Destruction issued by a qualifying destruction facility.

Although Offset Project Operators or Authorized Project Designees may engage in ongoing collection and destruction activities, destruction events that fall outside of the single calendar year designated for an offset project may only be counted as part of a separately registered offset project. Offset Project Operators or Authorized Project Designees may choose a shorter time horizon for a single offset project (e.g., 3 months or 6 months), but no offset project may run longer than a calendar year.

In order for multiple Certificates of Destruction to be included under a single offset project, all of the following conditions must be met:

- The Offset Project Operator or Authorized Project Designee of GHG emission reductions are the same for all ODS destroyed
- The qualifying destruction facility is the same for all Certificates of Destruction
- The destruction activities span a timeframe occurring in one calendar year
- No Certificate of Destruction is included as part of another offset project

For all offset projects, the end fate of the ODS must be destruction at either an approved Hazardous Waste Combustor (HWC) subject to the Resource Conservation and Recovery Act (RCRA), CAA, and the National Emissions Standards for Hazardous Air Pollutants (NESHAP) standards, or any other transformation or destruction facility that meets or exceeds the Montreal Protocol's Technology & Economic Assessment Panel (TEAP) standards provided in the *Report of the Task Force on Destruction Technologies* and listed in The Climate Action Reserve's *U.S. Ozone Depleting Substances Project Protocol Version 1.0.* All facilities must meet any applicable

requirements under the CAA and NESHAP. Non-RCRA permitted facilities cannot receive and destroy ODS materials that are classified as hazardous waste and must demonstrate compliance with the Title VI requirements of the CAA for destruction of ODS, as well as demonstrate destruction and removal efficiency (DRE) of 99.99% and emission levels consistent with the guidelines set forth in the aforementioned TEAP report.

2.3 Eligible ODS – Quantification Methodology

This protocol provides requirements for the accounting of GHG reductions from two general sources of ODS eligible under the offset project definition:

- **Refrigerants:** an offset project may collect eligible ODS refrigerant (see Section 2.3.1) from industrial, commercial or residential equipment, systems, and appliances or stockpiles, and destroy it at a qualifying destruction facility.

- **Foams:** an offset project may extract eligible ODS blowing agent (see Section 2.3.2) from appliance foams and destroy the concentrated ODS foam blowing agent at a qualifying destruction facility; or, an offset project may destroy intact foam sourced from building insulation at a qualified destruction facility.

A single offset project may incorporate ODS obtained from one or both of these ODS source categories. Tracking procedures and calculation methodologies differ depending on the source of ODS.

ODS that were produced for, used as, or intended for use as solvents, medical aerosols, or other ODS applications are not eligible.

2.3.1 Refrigerant Sources

This source category consists of ODS material produced prior to the U.S. production phase-out that could legally be sold into the U.S. refrigerant market. The ODS must originate from domestic U.S. supplies; imported refrigerant is not eligible under this protocol.

In the absence of an offset project, this material may be illegally vented or recovered for re-sale into the refrigerant recharge market. As described in Section 5.1.1, for GHG reduction calculation purposes, this protocol conservatively assumes that the refrigerant would be reclaimed.

Only destruction of the following ODS refrigerants is eligible to generate ARB or registry offset credits under this protocol:

- CFC-11
- CFC-12
- CFC-13
- CFC-113
- CFC-114

- CFC-115

ODS extracted from a foam source for use in refrigeration equipment is not considered part of this source category, and must instead be considered as a foam source. ODS sourced from federal government installations or stockpiles is not eligible under this protocol.

Additionally, all refrigerant collection, handling, and destruction must be performed in accordance with the reporting and operation requirements of the Regulation.

2.3.2 Foam Sources

This source category consists of ODS blowing agent entrained in foams that, absent a GHG reduction project, would have been released at end-of-life. The ODS blowing agent must originate from U.S. foam sources; imported foams are not eligible under this protocol.

Only the following ODS foam blowing agents are eligible to generate ARB or registry offset credits under this protocol:

- CFC-11
- CFC-12
- HCFC-22
- HCFC-141b

To be eligible to generate ARB or registry offset credits, the ODS blowing agent must be destroyed in one of two ways:

1. **ODS blowing agent extracted from appliance foam and destroyed.** The ODS blowing agent must be extracted from the foam to a concentrated form prior to destruction. This must be done under negative pressure to ensure that fugitive release of ODS cannot occur. The recovered ODS blowing agent must be collected, stored, and transported in cylinders or other hermetically sealed containers.

2. **Intact foam containing ODS blowing agent from buildings destroyed intact.** When the intact foam is separated from building panels, it must be stored, transported, and destroyed in sealed containers.

All foam collection, handling, extraction, and destruction must be performed in accordance with the reporting and operation requirements in the Regulation.

2.4 Offset Project Operator or Authorized Project Designee

The Offset Project Operator or Authorized Project Designee is responsible for offset project listing, monitoring, reporting, and verification. The Offset Project Operator or Authorized Project Designee must submit the information in the Regulation and in Appendix C. The Offset Project Operator or Authorized Project Designee must have legal authority to implement the offset project.

3 Eligibility Rules

Offset projects that meet the requirements in Section 2.2 must fully satisfy the eligibility requirements in the Regulation in addition to the eligibility rules in this protocol in order to be eligible to receive ARB or registry offset credits.

3.1 Location

For ODS destruction to be eligible as an offset project under this protocol, all ODS must be sourced from stocks in the United States or its territories and destroyed within the United States or its territories. In addition, 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) in 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.

3.2 Offset Project Commencement

For this protocol, Offset Project Commencement is defined as the date on which destruction activities commence, as documented on a Certificate of Destruction. Offset projects may always be submitted for listing prior to their commencement date.

3.3 Project Crediting Period

An ODS project is a discrete series of destruction events over a single calendar year. For the purposes of this protocol, it is assumed that, absent the offset project, the avoided ODS emissions would have occurred over a longer time horizon.

Under this protocol, the offset project crediting period is the period of time over which avoided emissions are quantified for the purpose of determining creditable GHG reductions. Specifically, ODS projects will be issued ARB or registry offset credits for the quantity of ODS that would have been released over a ten-year period following a destruction event. At the time the offset project is verified, ARB or registry offset credits are issued for all ODS emissions avoided by an offset project over the 10-year crediting period.

3.4 Additionality

Offset projects must meet the additionality requirements set out in the Regulation in addition to the requirements in this protocol.

The destruction of ODS by the U.S. government is common practice and considered business-as-usual, and therefore ineligible for crediting under this protocol.

3.5 Regulatory Compliance

As stated in the Regulation, an Offset Project Operators or Authorized Project Designees must fulfill all applicable local, regional and national requirements on environment impact assessments that apply based on the offset project location. Offset projects must also meet any other local, regional, and national requirements that might apply. Offset projects are not eligible to receive ARB or registry offset credits for GHG reductions that occur as the result of collection or destruction activities that are not in compliance with regulatory requirements.

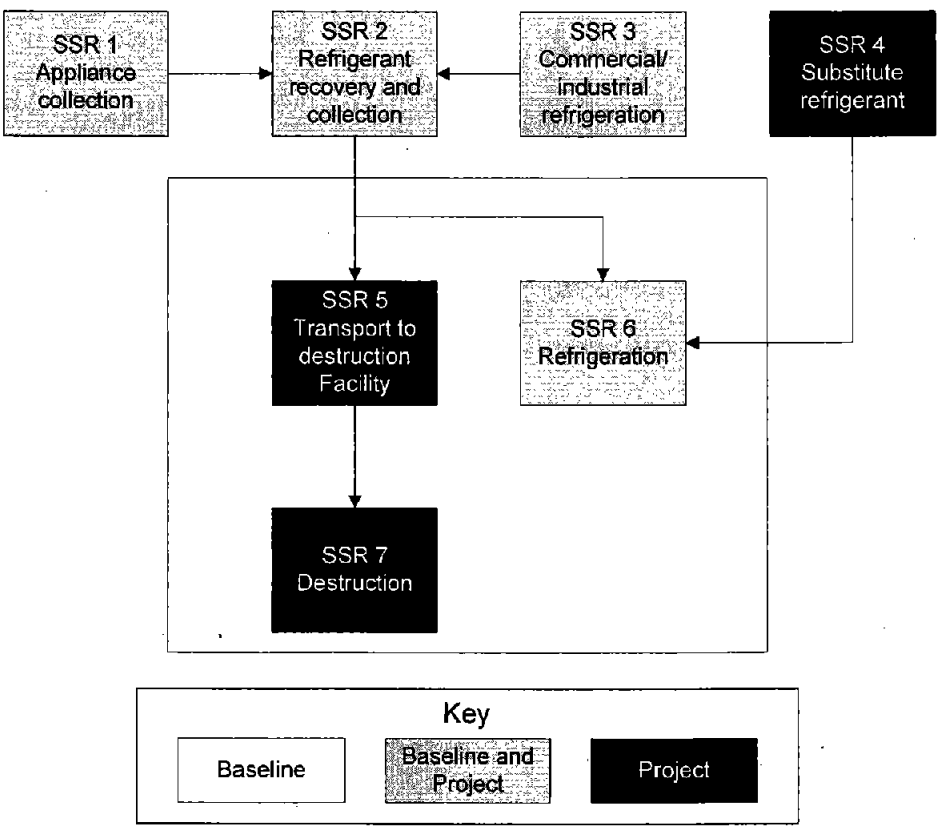
The regulatory compliance requirement extends to the operation of destruction facilities where the ODS is destroyed. Destruction facilities have the potential to contribute to environmental impacts beyond ozone depletion and climate change. Accordingly, all destruction facilities must meet the full burden of applicable regulatory requirements during the time the ODS destruction occurs. Any upsets or exceedences of permitted emission limits must be managed in keeping with an authorized startup, shutdown, and malfunction plan required by EPA (40 CFR 63.1206).

4 Offset Project Boundary – Quantification Methodology

The Offset Project Boundary delineates the GHG sources, GHG sinks, and GHG reservoirs (SSRs) that shall be assessed by the Offset Project Operators or Authorized Project Designees in order to determine the total net change in GHG emissions caused by an ODS project.

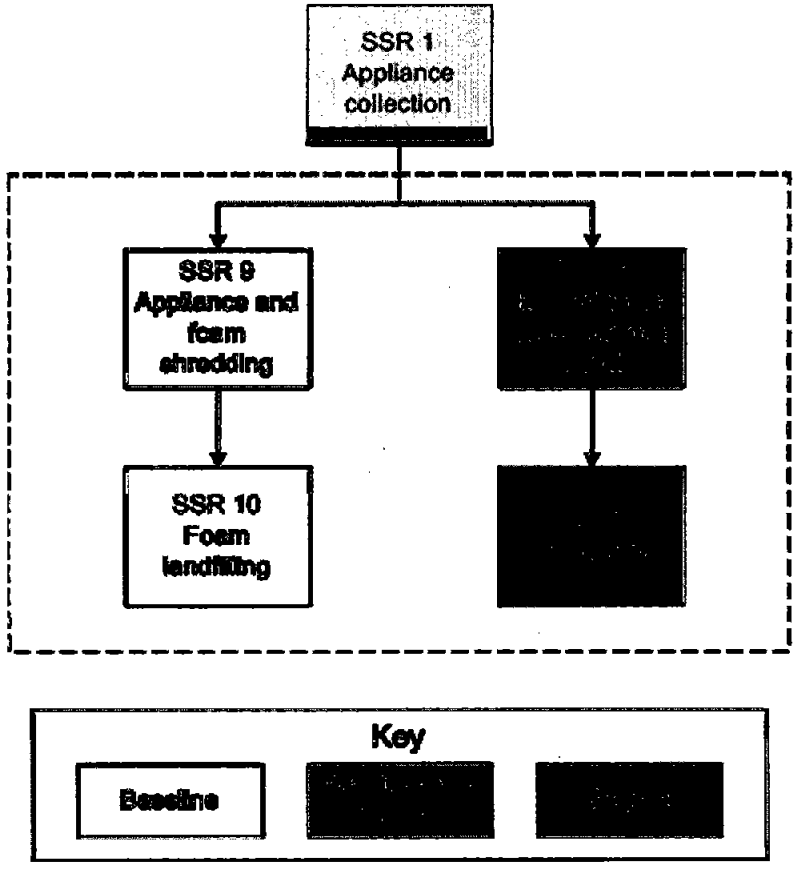
Figure 4.1, Figure 4.2, and Figure 4.3 provide a general illustration of the Offset Project Boundaries for different types of ODS destructions projects, indicating which SSRs are included or excluded from the boundary.

Table 4.1 gives greater detail on each SSR and provides information for all SSRs and gases that are excluded from the Offset Project Boundary.



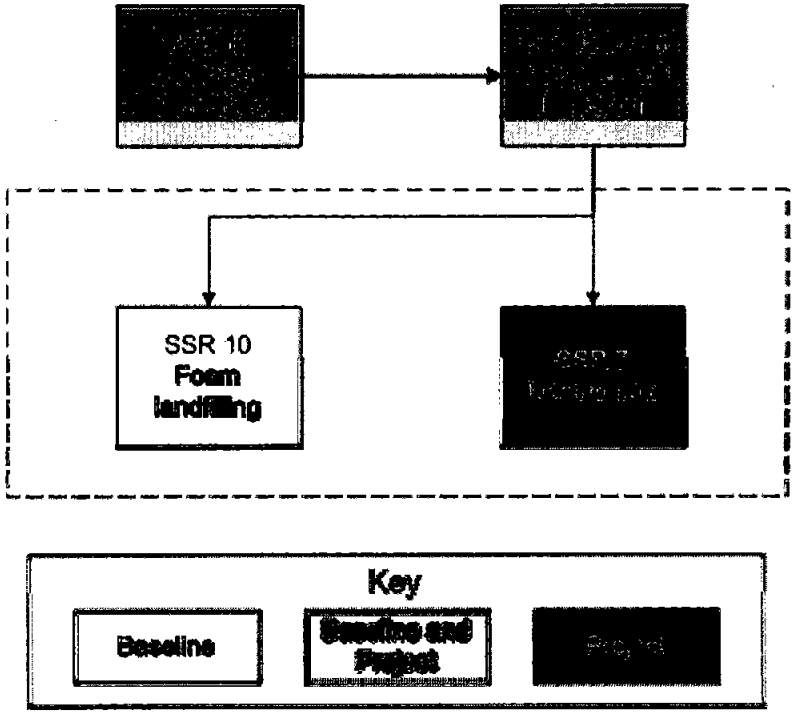
Note: Emissions from all GHG sources within the box above are accounted for within this protocol.

Figure 4.1. Illustration of the Offset Project Boundary for Refrigerant Projects



Note: Emissions from all GHG sources within the dashed box above are accounted for within this protocol.

Figure 4.2. Illustration of the Offset Project Boundary for Appliance Foam Projects



Note: Emissions from all GHG sources within the dashed box above are accounted for within this protocol.

Figure 4.3. Illustration of the Offset Project Boundary for Building Foam Projects

Table 4.1. Summary of Identified GHG Sources, GHG Sinks, and GHG Reservoirs – Quantification Methodology

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
1	Appliance Collection	Fossil fuel emissions from the collection and transport of end-of-life residential appliances	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
2	Refrigerant Recovery and Collection	Emissions of ODS from the recovery and collection of refrigerant at end-of-life or servicing	ODS	E	N/A
		Fossil fuel emissions from the recovery and collection of refrigerant at end-of-life or servicing	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
3	Commercial/ Industrial Refrigeration	Emissions of ODS from equipment leak and servicing	ODS	E	N/A
		Fossil fuel emissions from the operation of refrigeration and A/C equipment	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
4	Substitute Refrigerant Production	▪ Emissions of substitute refrigerant occurring during production ▪ Fossil fuel emissions from the production of substitute refrigerants	CO_2e	E	N/A
			CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
5	Transport to Destruction Facility	Fossil fuel emissions from the vehicular transport of ODS from aggregation point to final destruction facility	CO_2	I	**Baseline:**N/A **Project:** Estimated based on distance and weight transported

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
			CH_4	E	N/A
			N_2O	E	N/A
6	Refrigeration	Emissions of ODS from leaks and servicing through continued operation of equipment	ODS	I	**Baseline:** Estimated based on market-weighted emission rates **Project:** N/A
		Emissions of substitute from leaks and servicing through continued operation of equipment	CO_2e	I	**Baseline:** N/A **Project:** Estimated based on market-weighted emissions
		Indirect emissions from grid-delivered electricity	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
7	Destruction	Emissions of ODS from incomplete destruction at destruction facility	ODS	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
		Emissions from the oxidation of carbon contained in destroyed ODS	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
		Fossil fuel emissions from the destruction of ODS at destruction facility	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
			CH_4	E	N/A
			N_2O	E	N/A
		Indirect emissions from the use of grid-delivered electricity	CO_2	I	**Baseline:** N/A **Project:** Estimated based on ODS destroyed, or included in default deduction
			CH_4	E	N/A
			N_2O	E	N/A
8	Extraction of ODS Blowing Agent from Appliance Foam	Emissions of ODS released during the separation of foam from appliance	ODS	I	**Baseline:** N/A **Project:** Estimated based on recovery efficiency
9	Appliance and Foam Shredding	Emissions of ODS from the shredding of appliances for materials recovery, releasing ODS from foam	ODS	I	**Baseline:** Estimated based on total quantity of ODS destroyed and default shredding factors **Project:** N/A
10	Foam Landfilling	Emissions of ODS released from foam disposed of in landfills	ODS	I	**Baseline:** Estimated based on release and degradation of ODS in landfill **Project:** N/A
		Emissions of ODS degradation products from foam disposed of in landfills	HFC, HCFC	E	N/A
		Fossil fuel emissions from the transport and placement of shredded foam waste in landfill	CO_2	E	N/A
			CH_4	E	N/A

SSR		Source Description	Gas	Included (I) or Excluded (E)	Quantification Method
			N_2O	E	N/A
11	Building Demolition	Emissions of ODS from the demolition of buildings and damage to foam insulation panels	ODS	E	N/A
		Fossil fuel emissions from the demolition of buildings	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A
12	Foam transport and handling	Emissions of ODS released from foam during transport and handling	ODS	E	N/A
		Fossil fuel emissions from the transport and handling of building foam	CO_2	E	N/A
			CH_4	E	N/A
			N_2O	E	N/A

5 Quantifying GHG Emission Reductions - Quantification Methodology[4]

GHG emission reductions from an ODS project are quantified by comparing actual project emissions to calculated project baseline emissions. Project baseline emissions are an estimate of the GHG emissions from GHG sources within the Offset Project Boundary (see Section 4) that would have occurred in the absence of the ODS destruction project. Project emissions are actual GHG emissions that occur at GHG sources within the Offset Project Boundary. Project emissions must be subtracted from the project baseline emissions to quantify the offset project's total net GHG emission reductions (Equation 5.1).

An offset project may not span more than a single calendar year, although an Offset Project Operator or Authorized Project Designee may choose a shorter time length than 12 months for their offset project. GHG emission reductions must be quantified and verified at least once for the entire project time length. The quantification methodologies presented below are specified for a single reporting period, which may be less than or equal to the entire project time length.

Equation 5.1. Total Emission Reductions

$$ER_t = BE_t - PE_t$$

Where,

			Units
ER_t	=	Total quantity of GHG emission reductions during the reporting period	tCO_2e
BE_t	=	Total quantity of project baseline emissions during the reporting period	tCO_2e
PE_t	=	Total quantity of project emissions during the reporting period	tCO_2e

5.1 Quantifying Project Baseline Emissions

Total project baseline emissions must be estimated by calculating and summing the calculated project baseline emissions for all relevant SSRs (as indicated in Table 4.1) using Equation 5.2 and the supporting equations presented below. This includes GHG emissions from continued use of ODS in the secondary recharge market for refrigerants, and the GHG emissions from end-of-life disposal for foams.

Equation 5.2. Total Project Baseline Emissions

$$BE_t = BE_{refr} + BE_{foam}$$

Where, Units

[4] The entirety of Section 5 is considered a quantification method

BE	=	Total quantity of project baseline emissions	tCO_2e
BE_{refr}	=	Total quantity of project baseline emissions from refrigerant ODS	tCO_2e
BE_{foam}	=	Total quantity of project baseline emissions from ODS blowing agent	tCO_2e

Project baseline emissions for an ODS destruction project include the total calculated project baseline emissions from each eligible source category – ODS refrigerant and ODS blowing agent. If an offset project does not destroy any ODS from a particular source category, project baseline emissions for that source category are assumed to be zero.

Table 5.1 provides the applicable GWP to be used for calculating project baseline emissions in units of CO_2-equivalent metric tons.

Table 5.1. Global Warming Potential of Eligible ODS

ODS Species	100-yr Global Warming Potential (CO_2e)
CFC-11	4,750
CFC-12	10,900
CFC-13	14400
CFC-113	6130
CFC-114	10,000
CFC-115	7,370
HCFC-22	1,810
HCFC-141b	725

5.1.1 Calculating Project Baseline Emissions from Refrigerant Recovery and Resale

To ensure that actual GHG reductions from ODS destruction are not overestimated, this protocol project estimates baseline emissions according to the assumption that refrigerant ODS would be entirely recovered and resold.

Equation 5.3 shall be used to estimate the project baseline emissions that would have occurred over ten years had the destroyed ODS been used in existing refrigeration or air conditioning equipment. This equation requires the use of the ODS-specific GWP provided in Table 5.1, and emission rate (inclusive of both leak rate and servicing emissions) provided in Table 5.2.

Equation 5.3. Project Baseline Emissions from Refrigerant ODS

$$BE_{refr} = \sum_i \left(Q_{refr,i} \times ER_{refr,i} \times GWP_i\right)_i$$

Where,			Units
BE_{refr}	=	Total quantity of refrigerant project baseline emissions during the reporting period	tCO_2e
$Q_{refr,i}$	=	Total quantity of refrigerant ODS *i* sent for destruction by the offset project	tODS
$ER_{refr,i}$	=	10-year cumulative emission rate of refrigerant ODS *i* (see Table 5.2)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

Table 5.2. Emission rate for ODS refrigerants

ODS Species	Annual Weighted Average Emission Rate (%/yr)	10-year Cumulative Emission Rate (%/10 years) (ER_{refr})
CFC-11	20%	89%
CFC-12	26%	95%
CFC-13	9%	61%
CFC-113	20%	89%
CFC-114	14%	78%
CFC-115	9%	61%

5.1.2 Calculating Project Baseline Emissions from Shredding and/or Landfilling ODS Foam Blowing Agents

Depending on the origin of the foam, there are two different predominant baseline practices applicable to foams containing ODS blowing agent. The two baseline practices are as follows:

Origin	Baseline Practice
Insulation foam recovered from appliances	The foam is shredded, and subsequently landfilled
Foam recovered from building demolition	The foam is landfilled

Equation 5.4 shall be used to calculate the ODS emissions that would have resulted from the assumed project baseline practice applied to foams in the absence of the offset project. Project baseline emissions include the total GHG emissions that would have occurred as a result of foam shredding and landfilling. In order to calculate total project baseline emissions, offset projects destroying blowing agent extracted from appliance foam must calculate an offset project-specific recovery efficiency for use in Equation 5.4. Methods for developing the recovery efficiency can be found in Appendix A.

Equation 5.4. Project Baseline Emissions from ODS Blowing Agent

$$BE_{foam} = \sum_{i,j}\left[\left(BA_{app,i} + BA_{build,i}\right) \times ER_{i,j} \times GWP_i\right]$$

Where,

			Units
BE_{foam}	=	Total quantity of ODS blowing agent project baseline emissions	tCO_2e
$BA_{app,i,}$	=	Total quantity of ODS blowing agent *i* from appliance foam prior to treatment or processing, including blowing agent lost during processing	tODS
$BA_{build,i}$	=	Total quantity of ODS blowing agent *i* from building foam sent for destruction	tODS
$ER_{i,j}$	=	Lifetime emission rate of ODS blowing agent *i* from application *j* at end-of-life (see Table 5.3)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

$$BA_{app,i} = Q_{recover} + Q_{recover}\left(\frac{1-RE}{RE}\right)$$

Where,

			Units
$BA_{app,i}$	=	Total quantity of ODS foam blowing agent in foam prior to treatment or processing, including ODS foam blowing agent lost during processing	tODS
$Q_{recover}$	=	Total quantity of ODS foam blowing agent recovered during processing and sent for destruction, as determined according to Section 6.5	tODS
RE	=	Recovery efficiency of the ODS foam blowing agent recovery process[5] (See Appendix A for calculation of RE)	%

$$BA_{build} = Q_{foam} \times BA\%$$

Where,

BA_{build}	=	Total quantity of ODS blowing agent *i* from building foam sent for destruction	tODS
Q_{foam}	=	Total weight of foam with entrained ODS blowing agent sent for destruction	Metric tons
BA%	=	Mass ratio of ODS blowing agent entrained in building foam, as determined according to Section 6.3	% (0-1)

[5] RE does not extend to the ODS destruction efficiency, which is handled separately under this protocol.

The total percent of ODS foam blowing agent that would be released throughout the end-of-life processing (i.e., 10-year emission rates) for each ODS foam blowing agent and foam origin is presented in Table 5.3. These values include emissions from:

1. ODS blowing agent released during foam shredding,[6] plus
2. ODS blowing agent released during foam compaction, plus
3. Landfilled ODS blowing agent that is released during anaerobic conditions (but is not degraded).

Table 5.3. 10-year Emission Rates of Appliance and Building Foam at End-of-Life

ODS Blowing Agent	Appliance ODS blowing agent 10-year emission rate ($ER_{i,j}$)	Building ODS blowing agent 10-year emission rate ($ER_{i,j}$)
CFC-11	44%	20%
CFC-12	55%	36%
HCFC-22	75%	65%
HCFC-141b	50%	29%

5.2 Quantifying Project Emissions

Project emissions are actual GHG emissions that occur within the Offset Project Boundary as a result of offset project activities.

As shown in Equation 5.5, project emissions equal:

- GHG emissions from non-ODS substitutes (applicable only to refrigerant projects), plus
- GHG emissions from ODS foam blowing agent extraction (applicable only to appliance foam projects), plus
- GHG emissions from the transportation of ODS, plus
- GHG emissions from the destruction of ODS

Equation 5.5. Total Project Emissions

$$PE_t = Sub_{ref} + BA_{pr} + Tr + Dest$$

Where,

			Units
PE	=	Total quantity of project emissions during the reporting period	tCO_2e
Sub_{ref}	=	Total GHG emissions from substitute refrigerant	tCO_2e
BA_{pr}	=	Total quantity of ODS blowing agent from appliance foam released during ODS extraction	tCO_2e
Tr	=	Total GHG emissions from transportation of ODS (calculated using either the default value in Equation 5.8 or Equation 5.14)	tCO_2e
Dest	=	Total GHG emissions from the process associated with destruction of ODS (calculated using either the default value in Equation 5.8 or Equation 5.9 through Equation 5.13)	tCO_2e

[6] Note that the emissions from foam shredding have only been factored into the emission rates from appliance ODS blowing agents in Table 5.3, as building foam is not typically shredded before being landfilled.

5.2.1 Calculating Project Emissions from the Use of Refrigerant Substitutes

When refrigerant ODS are destroyed, continued demand for refrigeration will lead to the production and consumption of other refrigerant chemicals whose production is still legally allowed. Offset projects that destroy refrigerant ODS must therefore estimate the GHG emissions associated with the non-ODS substitute chemicals that are assumed to be used in their place. Like the estimates of project baseline emissions, substitute emissions shall be accounted for based on the projected emissions over a ten year crediting period.

Project emissions from the use of substitute refrigerants shall be calculated for all ODS refrigerant projects according to Equation 5.6 using the emission factors from Table 5.4. The use of site-specific substitute parameters (refrigerant, GWP, and leak rate) is not permitted.

Equation 5.6. Project Emissions from the Use of Non-ODS Refrigerants

$$Sub_{refr} = \sum_{i} (Qref_i \times SE_i)$$

Where,

			Units
Sub_{refr}	=	Total quantity of refrigerant substitute emissions	tCO_2e
$Qref_i$	=	Total quantity of refrigerant *i* sent for destruction	t
SE_i	=	Emission factor for substitute(s) for refrigerant *i*, per Table 5.4	tCO_2e/ tODS destroyed

ODS substitute emissions presented in Table 5.4 are based on the weighted average of expected new refrigerant supplies into the refrigeration market. These substitute refrigerants were modeled using the EPA Vintaging Model and data provided by industry sources.

Table 5.4. Refrigerant Substitute Emission Factors[78]

ODS Refrigerant	Substitute Emissions (t CO_2e/t ODS) (SE_i)
CFC-11	223
CFC-12	686
CFC-13	7144
CFC-113	220
CFC-114	659
CFC-115	1139

5.2.2 Calculating Project Emissions from ODS Blowing Agent Extracted from Appliance Foam

Offset projects that extract ODS blowing agent from appliance foam must account for the GHG emissions of ODS that occur during processing, separation, and extraction using Equation 5.7. These GHG emissions are calculated in Equation 5.7 based on the quantity of ODS blowing agent sent for destruction ($BA_{app,i}$, as calculated in Equation 5.4), and an offset project-specific recovery efficiency that represents the percentage of ODS that is not lost during these steps. Recovery efficiency must be independently established once for each individual offset project according to the methods provided in Appendix A.

Equation 5.7. Calculating Project Emissions from the Release of ODS Blowing Agent during Processing

$$BA_{pr} = \sum_i \left(BA_{app,i} \times (1 - RE) \times GWP_i \right)$$

Where,

			Units
BA_{pr}	=	Total quantity of ODS blowing agent from appliance foam released during ODS extraction	tCO_2e
$BA_{app,i}$	=	Total quantity of appliance ODS foam blowing agent in foam prior to treatment or processing, including ODS foam blowing agent lost during processing (see Equation 5.4 to calculate this term)	tODS
RE	=	Recovery efficiency of the ODS foam blowing agent recovery process (See Appendix A to calculate RE)	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

[7]IPCC (2007). Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Table 2.14 Errata. Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.) Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html

[8] Substitute emissions were developed using a weighted average of 10-year emissions rates in CO_2 equivalent based on the market share, amounts, and leakage rates of the ODS subsitutes. If a substitute is a mix of gases, the GWP for each gas and proportion of each in the mixture is used to determine the GWP of the mixture. The GWPs for the refrigerant substitutes are from the Second Assessment Report, cited in the above footnote.

5.2.3 Calculating Default Project Emissions from ODS Transportation and Destruction

Offset projects must account for GHG emissions that result from the transportation and destruction of ODS. Because these GHG emission sources are both individually and in aggregate very small, the protocol default emission factors for ODS projects are based on conservative assumptions and the SSRs outlined in Table 4.1:

- 7.5 metric tons CO_2e per metric ton ODS for refrigerant or extracted ODS blowing agent projects
- 75 metric tons CO_2e per metric ton ODS for intact building foam projects

These emission factors aggregate both transportation and destruction emissions. An Offset Project Operators or Authorized Project Designee has the option of using the default emission factors or using the methods in Sections 5.2.4 and 5.2.5 to calculate offset project-specific emissions.

Equation 5.8 shall be used to calculate ODS transportation and destruction emissions if default emission factors are used. If an Offset Project Operator or Authorized Project Designee elects not to use the default emission factors, GHG emissions associated with transportation and destruction of ODS must be calculated separately.

Equation 5.8. Project Emissions from Transportation and Destruction Using the Default Emission Factors

$$Tr + Dest = \sum_i \left(Q_{ODS,i} \times EF_i \right)$$

Where,

			Units
Tr+Dest	=	Total GHG emissions from ODS transportation and destruction, as calculated using default emission factors	tCO_2e
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	tODS
EF_i	=	Default emission factor for transportation and destruction of ODS *i* (7.5 for refrigerant or extracted ODS blowing agent projects, 75 for intact building foam projects)	tCO_2e/ tODS

5.2.4 Calculating Site-Specific Project Emissions from ODS Destruction

Under this protocol, ODS must be destroyed at facilities that have a RCRA permit for hazardous waste destruction or that demonstrate compliance with the TEAP recommendations. TEAP facilities are required to demonstrate their ability to achieve destruction efficiencies upwards of 99.99% for substances with thermal stability ratings higher than the ODS included under this protocol.[9] Associated with the operation of these facilities are emissions of CO_2 from the fuel and electricity used to power the destruction, as well as emissions of undestroyed ODS. Equation 5.9 through Equation 5.11 provide requirements for calculating GHG emissions from ODS destruction in cases where Offset Project Operators or Authorized Project Designees opt not to use the default factors provided in Section 5.2.3.

Equation 5.9. Project Emissions from the Destruction of ODS

$$Dest = FF_{dest} + EL_{dest} + ODS_{emissions} + ODS_{CO2}$$

Where,

			Units
Dest	=	Total GHG emissions from the destruction of ODS	tCO_2e
FF_{dest}	=	Total GHG emissions from fossil fuel used in the destruction facility (Equation 5.10)	tCO_2
EL_{dest}	=	Total indirect GHG emissions from grid electricity used at the destruction facility (Equation 5.11)	tCO_2
$ODS_{emissions}$	=	Total GHG emissions of undestroyed ODS (Equation 5.12)	tCO_2e
ODS_{CO2}	=	Total GHG emissions of CO_2 from ODS oxidation (Equation 5.13)	tCO_2

Equation 5.10. Fossil Fuel Emissions from the Destruction of ODS

$$FF_{dest} = \frac{\sum_k \left(FF_{PR,k} \times EF_{FF,k} \right)}{1000}$$

Where, Units

[9] Demonstration of compliance with TEAP recommendations must be conducted by a third party verifier.

FF_{dest}	=	Total carbon dioxide emissions from the destruction of fossil fuel used to destroy ODS	tCO_2
$FF_{PR,k}$	=	Total fossil fuel *k* used to destroy ODS	volume fossil fuel
$EF_{FF,k}$	=	Fuel specific emission factor (see Appendix B)	kg CO_2/ volume fossil fuel
1000	=	kg/t of CO_2	$kgCO_2$/ tCO_2

Equation 5.11. Electricity Emissions from the Destruction of ODS

$$EL_{dest} = \frac{(EL_{PR} \times EF_{EL})}{2204.6}$$

Where,

			Units
EL_{dest}	=	Total carbon dioxide emissions from the consumption of electricity from the grid used to destroy ODS	tCO_2
EL_{PR}	=	Total electricity consumed to destroy ODS	MWh
EF_{EL}	=	Carbon emission factor for electricity used (see Appendix B)	lb CO_2/ MWh

Equation 5.12. Calculating Project Emissions from ODS Not Destroyed

$$ODS_{emissions} = \sum_i Q_{ODS,i} \times 0.01\% \times GWP_i$$

Where,

			Units
$ODS_{emissions}$	=	Total GHG emissions of undestroyed ODS	tCO_2e
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	tODS
0.01	=	Maximum allowable percent of ODS fed to destruction that is not destroyed	%
GWP_i	=	Global warming potential of ODS *i* (see Table 5.1)	tCO_2e/ tODS

Equation 5.13. Calculating Project Emissions of CO_2 from the Oxidation of ODS

$$ODS_{CO_2} = \sum_i Q_{ODS,i} \times 0.9999 \times CR_i \times \frac{44}{12}$$

Where,

			Units
ODS_{CO2}	=	Total GHG emissions of CO_2 from ODS oxidation	tCO_2
$Q_{ODS,i}$	=	Total quantity of ODS *i* sent for destruction in the project	tODS
0.9999	=	Minimum destruction efficiency of destruction facility	% (0-1)

CR_i	=	Carbon ratio of ODS *i* CFC-11: 12/137 CFC-12: 12/121 CFC-113: 12/90 CFC-114: 24/187 CFC-115: 12/74 HCFC-22: 12/87 HCFC-141b: 24/117	mole C/ mole ODS
44/12	=	Ratio of CO_2 to C	mole CO_2/ mole C

5.2.5 Calculating Site-Specific Project Emissions from ODS Transportation

As part of any ODS destruction project, ODS will be transported from aggregators to destruction facilities, and GHG emissions from this transportation must be accounted for under this protocol. Equation 5.14 must be used to calculate CO_2 emissions associated with the transport of ODS in cases where an Offset Project Operator or Authorized Project Designee chooses not to use the default emission factors presented in Section 5.2.3. Emissions shall be calculated for each leg of the transportation process separately, and then summed according to Equation 5.14 below.

Equation 5.14. Calculating Project Emissions from the Transportation of ODS

$$Tr = \sum_i \left(\frac{TMT_i \times EF_{TMT}}{1000} \right)$$

Where,			Units
Tr	=	Total GHG emissions from transportation of ODS	tCO_2e
TMT_i	=	Ton-miles-traveled[10] for ODS *i* destroyed (to be calculated including the ODS, any accompanying material, and containers from point of aggregation to destruction)	ton-miles
EF_{TMT}	=	CO_2 emissions per ton-mile-traveled On-road truck transport = 0.297 Rail transport = 0.0252 Waterborne craft = 0.048 Aircraft = 1.5279	$kgCO_2$ / ton-mile
1000	=	Conversion from kg to tons	kg/ton

6 Project Documentation Requirements

An ODS destruction project must comply with documentation requirements in the Regulation. The monitoring, reporting, and record retention requirements cover all aspects of this protocol and the documentation must specify how data for all relevant parameters in Table 6.2 was collected and recorded.

[10] A ton-mile is defined as the product of the distance travelled in miles and the mass transported in metric tons. Therefore, half a ton transported four miles is equal to two ton-miles.

The Offset Project Operator or Authorized Project Designee is responsible for monitoring the performance of the offset project and ensuring that there is no double-counting of GHG reductions associated with ODS destruction.

6.1 Point of Origin Documentation Requirements

As in the Regulation, the Offset Project Operators or Authorized Project Designee is responsible for collecting data on the point of origin of each quantity of ODS as part of tracking chain of custody, as defined in Table 6.1. The Offset Project Operator or Authorized Project Designee must maintain detailed acquisition records of all quantities of ODS destroyed under the offset project.

Table 6.1. Identification of Point of Origin

ODS	Defined Point of Origin
1. Refrigerant ODS stockpiled for greater than 24 months; or stockpiled prior to the adoption date of this protocol and destroyed within twelve months of the adoption date of this protocol.	Location of stockpile
2. Refrigerant ODS quantities less than 500 lbs	Location where ODS is first aggregated with other ODS to greater than 500 lbs[b]
3. Refrigerant ODS quantities greater than 500 lbs	Site of installation where ODS is removed
4. ODS blowing agent extracted from foam	Facility where ODS blowing agent is extracted
5. ODS blowing agent in building foam	Location of building from which foam was taken

[b] The point of origin for ODS collected by service technicians in individual quantities less than 500 pounds is defined as the holding facility at which several small quantities were combined and exceeded 500 pounds in aggregate. That is, those handling quantities less than 500 pounds need not provide documentation. However, once smaller quantities are aggregated and exceed 500 pounds collectively, tracking will be required from that location and point in time forward.

All data must be generated *at the time of collection* from the point of origin. Documentation of the point of origin of ODS must include the following:

- Facility name and physical address
- Point of origin zip code
- Identification of the system by serial number, if available, or description, location, and function, if serial number is unavailable (for quantities greater than 500 pounds)
- Serial or ID number of containers used for storage and transport

6.2 Chain of Custody Documentation Requirements

In conjunction with establishing the point of origin for each quantity of ODS, the Offset Project Operators or Authorized Project Designee must also document the custody and ownership of ODS beginning from the point of origin as required in the Regulation. These records shall include names, addresses, and contact information of persons/entities buying/selling material for destruction and the quantity of the material (the combined mass of refrigerant and contaminants) bought/sold. Such records may include Purchase Orders, Purchase Agreements, packing lists, bills of lading, lab test results, transfer container information, receiving inspections, freight bills, transactional payment information, and any other type of information that will support previous

ownership of the material and the transfer of beneficial ownership rights. The verifier will review these records and will perform other tests necessary to authenticate the previous owners of the material, the physical transfer of the product, and the transfer of beneficial ownership rights to the Offset Project Operator or Authorized Project Designee.

6.3 Building Foam Requirements – Quantification Methodology

The following information shall be collected and recorded related to ODS blowing agents from building insulation foam destroyed by the offset project:

- Building address
- Date of construction
- Blowing agent used
- Approximate building dimensions

All recovered foam pieces must be placed in air- and water-tight storage for transport to the destruction facility.

ODS blowing agent from building insulation foam may be destroyed intact without extraction of the blowing agent if the following procedures are followed to characterize the mass of foam and type(s) and mass ratio of ODS blowing agent contained in that foam.

1. The mass of the foam shall be determined through weight measurements taken at the destruction facility on scales calibrated quarterly. Scales are considered calibrated if they demonstrate accuracy of +/- 5% of reading.

2. The composition and mass ratio of the ODS foam blowing agent(s) present in the building insulation foam shall be determined based on a selection of a minimum two samples per building surface taken prior to demolition. Accordingly, a building with four exterior walls and a roof would be required to analyze a total of 10 samples: two for each wall, and two for the roof.

3. All samples must be collected and analyzed according to the following requirements:

    - Each foam sample shall be at a minimum 2 inches in length, 2 inches in width, and 2 inches thick
    - Each sample shall be placed and sealed in a separate waterproof, air-tight container, that is at minimum 2 millimeters thick for storage and transport
    - The analysis of ODS foam blowing agent content and mass ratio shall be done at an independent laboratory unaffiliated with the Offset Project Operator or Authorized Project Designee
    - The analysis shall be done using the heating method to extract ODS foam blowing agent from the foam samples described in Scheutz et al (2007)

referenced in The Climate Action Reserve's *U.S. Ozone Depleting Substances Project Protocol Version 1.0*:

- Each sample shall be prepared to a thickness no greater than 1 cm, placed in a 1123 mL glass bottle, weighed using a calibrated scale, and sealed with Teflon-coated septa and aluminum caps
- To release the ODS blowing agent from the foam, the samples must be incubated in an oven for 48 hours at 140 degrees C
- When cooled to room temperature, gas samples must be redrawn from the headspace and analyzed by gas chromatography
- The lids must be removed after analysis, and the headspace must be flushed with atmospheric air for approximately 5 minutes using a compressor. Afterwards, septa and caps must be replaced and the bottles subjected to a second 48-hr heating step to drive out the remaining ODS blowing agent from the sampled foam
- When cooled down to room temperature after the second heating step, gas samples must be redrawn from the headspace and analyzed by gas chromatography

- The mass of ODS blowing agent(s) recovered shall then be divided by the total mass of the initial foam samples prior to analysis to determine the mass ratio of each ODS foam blowing agent present

The results from all samples from a single building shall be averaged to determine the mass ratio of blowing agent to foam, and this value multiplied by the weight of destroyed foam. The result shall represent the total quantity of ODS blowing agent from building foams destroyed for that building, and shall be used for the quantity as BA_{build} in Equation 5.4.

These practices shall be documented and must be demonstrated during verification activities.

6.4 Appliance Foam Requirements – Quantification Methodology

The following information shall be collected and recorded related to ODS blowing agent from appliance foams destroyed by the project:

- Number of appliances processed
- Facility at which ODS foam blowing agent is extracted to concentrated form
- Facility at which appliance de-manufacture occurs, if applicable

All appliance foam must be processed to recover and destroy concentrated ODS blowing agent. The following requirements must be met:

- The ODS blowing agent must be extracted from the foam to a concentrated form prior to destruction
- ODS blowing agent must be extracted under negative pressure to ensure that fugitive release of ODS is limited

- The recovered ODS blowing agent must be collected, stored, and transported in containers meeting U.S. Department of Transportation (DOT) standards for refrigerants

Extraction of the foam blowing agent may be performed using any technology capable of recovering concentrated ODS foam blowing agent. The processes, training, QA/QC, and management systems must be documented. The same process must be followed during project implementation and during the calculation of the project-specific recovery efficiency, as described in Appendix A.

Concentrated ODS blowing agent shall be measured according to the procedures provided in Section 6.5.

6.5 Concentrated ODS Composition and Quantity Analysis Requirements – Quantification Methodology

The requirements of this section must be followed to determine the quantities of both ODS refrigerants and concentrated ODS blowing agent. Prior to destruction, the precise mass and composition of ODS to be destroyed must be determined. The following analysis must be conducted:

Mass shall be determined by individually measuring the weight of each container of ODS: (1) when it is full prior to destruction; and (2) after it has been emptied and the contents have been fully purged and destroyed. The mass of ODS and any contaminants is equal to the difference between the full and empty weight, as measured. The following requirements must be met when weighing the containers of ODS:

1. A single scale must be used for generating both the full and empty weight tickets at the destruction facility
2. The scale used must be properly calibrated per the facility's RCRA permit, or for non-RCRA facilities calibrated at least quarterly to an accuracy of within 5% of reading. RCRA facilities that do not have calibration requirements defined in their RCRA permits must calibrate scales quarterly to an accuracy of within 5% of reading.
3. The full weight must be measured no more than two days prior to commencement of destruction per the Certificate of Destruction
4. The empty weight must be measured no more than two days after the conclusion of destruction per the Certificate of Destruction

Composition and concentration of ODS shall be established for each individual container by taking a sample from each container of ODS and having it analyzed for composition and concentration at an Air-Conditioning, Heating and Refrigeration Institute (AHRI) certified laboratory using the AHRI 700-2006 standard as referenced in The Climate Action Reserve's *U.S. Ozone Depleting Substances Project Protocol*

Version 1.0. The laboratory performing the composition analysis must not be affiliated with the Offset Project Operator or Authorized Project Designee.

The following requirements must be met for each sample:

1. The sample must be taken while ODS is in the possession of the company that will destroy the ODS
2. Samples must be taken by a technician unaffiliated with the Offset Project Operator or Authorized Project Designee [11]
3. Samples must be taken with a clean, fully evacuated sample bottle that meets applicable U.S. Department of Transportation requirements with a minimum capacity of one pound
4. Each sample must be taken in liquid state
5. A minimum sample size of one pound must be drawn for each sample
6. Each sample must be individually labeled and tracked according to the container from which it was taken, and the following information recorded:
    a) Time and date of sample
    b) Name of Offset Project Operator or Authorized Project Designee
    c) Name of technician taking sample
    d) Employer of technician taking sample
    e) Volume of container from which sample was extracted
    f) Ambient air temperature at time of sampling[12]
7. Chain of custody for each sample from the point of sampling to the AHRI lab must be documented by paper bills of lading or electronic, third-party tracking that includes proof of delivery (e.g., FedEx, UPS)

All project samples shall be analyzed using ARI 700-2006 to confirm the mass percentage and identity of each component of the sample. The analysis shall provide:

1. Identification of the refrigerant
2. Purity (%) of the ODS mixture by weight using gas chromatography
3. Moisture level in parts per million. The moisture content of each sample must be less than 75% of the saturation point for the ODS based on the temperature recorded at the time the sample was taken.
4. Analysis of high boiling residue, which must be less than 10% by mass
5. Analysis of other ODS in the case of mixtures of ODS, and their percentage by mass

If any of the requirements above are not met, no GHG reductions may be verified for ODS destruction associated with that container.

[11] For instances where the Offset Project Operator or Authorized Project Designee is the destruction facility itself, an outside technician must be employed for taking samples.

[12] Offset projects that destroy ODS prior to the adoption date of this protocol may use proxy data from NOAA recording stations in the area.

If the container holds non-mixed ODS (defined as greater than 90% composition of a single ODS species) no further information or sampling is required to determine the mass and composition of the ODS.

If the container holds mixed ODS, which is defined as less than 90% composition of a single ODS species, the Offset Project Operator or Authorized Project Designee must meet additional requirements as provided in Section 6.5.1.

6.5.1 Analysis of Mixed ODS

If a container holds mixed ODS, its contents must also be processed and measured for composition and concentration according to the requirements of this section (in addition to the requirements of Section 6.5). The sampling required under this section may be conducted at the final destruction facility or prior to delivery to the destruction facility. However, the circulation and sampling activities must be conducted by a third-party (i.e., not the Offset Project Operator or Authorized Project Designee), and by individuals who have been properly trained for the functions they perform. Circulation and sampling may be conducted at the Offset Project Operator or Authorized Project Designee's facility, but all activities must be directed by a properly trained and contracted third-party. The offset project's documentation must specify the procedures by which mixed ODS are analyzed.

The composition and concentration of ODS on a mass basis must be determined using the results of the analysis of this section for each container. The results of the composition analysis in Section 6.5 shall be used by verifiers to confirm that the destroyed ODS is the same ODS that is sampled under these requirements.

Prior to sampling, the ODS mixture must be circulated in a container that meets all of the following criteria:

1. The container has no solid interior obstructions[13]
2. The container was fully evacuated prior to filling
3. The container must have sampling ports to sample liquid and gas phase ODS
4. The sampling ports must be located in the middle third of the container (i.e., not at one end or the other)
5. The container and associated equipment can circulate the mixture via a closed loop system from the bottom to top

If the original mixed ODS container does not meet these requirements, the mixed ODS must be transferred into a temporary holding tank or container that meets all of the above criteria. The weight of the contents placed into the temporary container shall be calculated and recorded. During transfer of ODS into and out of the temporary container, ODS shall be recovered to the vacuum levels required by the U.S. EPA for that ODS (see 40 CFR 82.156).

[13] Mesh baffles or other interior structures that do not impede the flow of ODS are acceptable.

Once the mixed ODS is in a container or temporary storage unit that meets the criteria above, circulation of mixed ODS must be conducted as follows:

1. Liquid mixture shall be circulated from the liquid port to the vapor port
2. A volume of the mixture equal to two times the volume in the container shall be circulated
3. Circulation must occur at a rate of at least 30 gallons/minute
4. Start and end times shall be recorded

Within 30 minutes of the completion of circulation, a minimum of two samples shall be taken from the bottom liquid port according to the procedures in Section 6.5. Both samples shall be analyzed at an AHRI approved laboratory per the requirements of Section 6.5. The analysis will determine the GWP weighted concentrations for both samples. The Offset Project Operator or Authorized Project Designee will use the results with the lesser GWP-weighted concentration for the protocol.

6.6 Destruction Facility Requirements – Quantification Methodology

Destruction of ODS must occur at a facility that meets all of the aforementioned TEAP requirements. This includes any RCRA-permitted HWC as well as any other facility that meets the aforementioned TEAP requirements. Facilities permitted as RCRA HWCs are considered to meet the guidelines by default; no further testing for TEAP compliance is required.

At the time of ODS destruction, all destruction facilities must have a valid Title V air permit, if applicable, and any other air or water permits required by local, state, or federal law to destroy ODS. Facilities must document compliance with all monitoring and operational requirements associated with the destruction of ODS materials, as dictated by these permits, including emission limits, calibration schedules, and training. Any upsets or exceedences must be managed in keeping with an authorized startup, shutdown, and malfunction plan. Non-RCRA facilities must further document operation consistent with the TEAP requirements. A third party must certify that the non-RCRA facility meets the TEAP requirements.

Operating parameters during destruction of ODS material shall be monitored and recorded as described in the Code of Good Housekeeping approved by the Montreal Protocol. This data will be used in the verification process to demonstrate that during the destruction process, the destruction unit was operating similarly to the period in which the DRE[14] was calculated. The DRE is determined using the Comprehensive Performance Test (CPT)[15] as a proxy for DRE and is disclosed to the public in the destruction facility's Title V operating permit.

To monitor that the destruction facility operates in accordance with applicable regulations and within the parameters recorded during DRE testing, the following parameters must be tracked continuously during the entire ODS destruction process:

[14] DRE disclosed in Title V operating permit.
[15] CPT must have been conducted with a less combustible chemical than the ODS in question.

- The ODS feed rate
- The amount and type of consumables used in the process (not required if default project emission factor for transportation and destruction is used)
- The amount of electricity and amount and type of fuel consumed by the destruction unit (not required if default project emission factor for transportation and destruction is used)
- Operating temperature and pressure of the destruction unit during ODS destruction
- Effluent discharges measured in terms of water and pH levels
- Continuous emissions monitoring system (CEMS) data on the emissions of carbon monoxide during ODS destruction

The Offset Project Operator or Authorized Project Designee must maintain records of all of these parameters for review during the verification process.

Destruction facilities shall provide valid Certificate(s) of Destruction for all ODS destroyed as part of the offset project. The Certificate of Destruction shall include:

- Offset Project Operator or Authorized Project Designee
- Destruction facility
- Generator name
- Certificate of Destruction ID number
- Serial, tracking, or ID number of all containers for which ODS destruction occurred
- Weight and type of material destroyed from each container
- Start destruction date
- Ending destruction date

6.7 Monitoring Parameters – Quantification Methodology

Prescribed monitoring parameters necessary to calculate project baseline and offset project emissions are provided in Table 6.2. In addition to the parameters below that are used in the calculations provided in Section 5, the Offset Project Operators or Authorized Project Designees is responsible for maintaining all records required by the Regulation and this protocol.

Table 6.2. ODS Project Monitoring Parameters – Quantification Methodology

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
		Legal Requirement Test	N/A	For each offset project		Must be monitored and determined for each project
		Mass of ODS (or ODS mixture) in each container	mass of mixture	Per container	M	Must be determined for each container
		Concentration of ODS (or ODS mixture) in each container	mass ODS/ mass of mixture	Per container	M	Must be determined for each container
Equation 5.1	ER_t	Total quantity of GHG emission reductions during the reporting period	tCO_2e	For each offset project	C	
Equation 5.1, Equation 5.2	BE_t	Total quantity of project baseline emissions during the reporting period	tCO_2e	For each offset project	C	
Equation 5.1, Equation 5.5	PE_t	Total quantity of project emissions during the reporting period	tCO_2e	For each offset project	C	
Equation 5.2, Equation 5.3	BE_{refr}	Total quantity of project baseline emissions from refrigerant ODS	tCO_2e	For each offset project	C	
Equation 5.2, Equation 5.4	BE_{foam}	Total quantity of project baseline emissions from ODS blowing agent	tCO_2e	For each offset project	C	
Equation 5.3, Equation 5.6	$Q_{refr,i}$	Total quantity of refrigerant ODS *i* sent for destruction	tODS	For each offset project	M	
Equation 5.3	$ER_{refr,i}$	10-year cumulative emission rate of refrigerant ODS *i*	0 - 1.0	N/A	R	See Table 5.1
Equation 5.3, Equation 5.4, Equation 5.7, Equation 5.12	GWP_i	Global warming potential of ODS *i*	tCO_2e/ tODS	N/A	R	See Table 5.1
Equation 5.4, Equation 5.7	$BA_{app,i,}$	Total quantity of ODS blowing agent *i* from appliance foam prior to treatment or processing, including blowing agent lost during processing	tODS	For each offset project	C	

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.4	$BA_{build,i}$	Total quantity of ODS blowing agent *i* from building foam sent for destruction.	tODS	For each offset project	C	
Equation 5.4	$ER_{i,j}$	Lifetime emission rate of ODS blowing agent *i* from application *j* at end-of-life (see Table 5.3)	% (0-1)	N/A	R	
Equation 5.4	$Q_{recover}$	Total quantity of ODS foam blowing agent recovered during processing and sent for destruction	tODS	For each offset project	M	
Equation 5.4, Equation 5.7	RE	Recovery efficiency of the ODS foam blowing agent recovery process	% (0-1)	Once for each offset project	C	See Appendix A for calculation of RE
Equation 5.4	Q_{foam}	Total weight of foam with entrained ODS blowing agent sent for destruction	tonnes	For each offset project	M	
Equation 5.4	BA%	Mass ratio of ODS blowing agent entrained in building foam, as determined according to Section 6.3	% (0-1)	For each offset project	M	
Equation 5.5, Equation 5.6	Sub_{refr}	Total GHG emissions from substitute refrigerant	tCO_2e	For each offset project	C	
Equation 5.5, Equation 5.7	$BA_{pr,i}$	Total quantity of ODS foam blowing agent *i* from appliance foam released during ODS extraction	tCO_2e	For each offset project	C	
Equation 5.5, Equation 5.8, Equation 5.14	Tr	Total GHG emissions from transportation of ODS	tCO_2e	For each offset project	C	
Equation 5.5, Equation 5.8, Equation 5.9	Dest	Total GHG emissions from the destruction process associated with destruction of ODS	tCO_2e	For each offset project	C	
Equation 5.6	SE_i	Emission factor for substitute emissions of refrigerant *i*, per Table 5.5	tCO_2e/ tODS destroyed	Per container	R	See Table 5.4 (see 10 for summary of the development of SE)

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
Equation 5.8, Equation 5.12, Equation 5.13	$Q_{ODS,i}$	Total quantity of ODS *i* sent for destruction	tODS	For each offset project	M	
Equation 5.8,	EF_i	Default emission factor for transportation and destruction of ODS *i*	tCO_2e/ tODS	N/A	R	Equal to 7.5 for refrigerant projects, and 75 for foam projects
Equation 5.9, Equation 5.10	FF_{dest}	Total GHG emissions from fossil fuel used in the destruction facility	tCO_2e	For each offset project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.11	EL_{dest}	Total GHG emissions from grid electricity at the destruction facility	tCO_2e	For each offset project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.10	$FF_{PR,k}$	Total fossil fuel *k* used to destroy ODS	tCO_2e	For each offset project	M	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.10	$EF_{FF,k}$	Fuel specific emission factor	$kgCO_2$/ volume fuel	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.11	EL_{PR}	Total electricity consumed to destroy ODS	MWh	For each offset project	M	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.11	EF_{EL}	Carbon emission factor for electricity used	$lbCO_2$/ MWh	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.12	$ODS_{emissions}$	Total GHG emissions of un-destroyed ODS	tCO_2e	For each offset project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.9, Equation 5.13	ODS_{CO2}	Total emissions of CO_2 from ODS oxidation	tCO_2	For each offset project	C	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.13	CR_i	Carbon ratio of ODS *i*	mole C/ mole ODS	N/A	R	Use only if calculating site-specific project emissions from ODS destruction
Equation 5.14	TMT_i	Tonne-miles-traveled for ODS *i* destroyed	tonne-miles	For each offset project	M	Use only if calculating site-specific project emissions from ODS transportation
Equation 5.14	EF_{TMT}	Mode-specific emission factor	$kgCO_2$/ tonne-mile	N/A	R	Use only if calculating site-specific project emissions from ODS transportation

7 Reporting Parameters

General requirements for reporting and record retention are included in the Regulation. This section provides additional requirements on reporting rules and procedures specific to this protocol. A priority of this protocol is to facilitate consistent and transparent information disclosure by the Offset Project Operator or Authorized Project Designee.

7.1 Annual Reporting Requirements

The Offset Project Operators or Authorized Project Designees must submit an Offset Project Data Report according to the requirements in the Regulation. The Offset Project Data Report must include the information listed in the Regulation and this protocol and cover a single Reporting Period. See the Regulation and Appendix D for specific requirements.

7.2 Document Retention

The Offset Project Operator or Authorized Project Designee is required to retain all documentation and information outlined in the Regulation and this protocol. Record retention requirements are set forth in the Regulation.

System information the Offset Project Operator or Authorized Project Designee should retain includes, but is not limited to:

- All data inputs for the calculation of the offset project emission reductions, including all required sampled data
- Copies of all permits, Notices of Violations (NOVs), and any relevant administrative or legal consent orders dating back at least 3 years prior to the project commencement date
- Destruction facility monitor information (CEMS data, DRE documentation, scale readings, calibration procedures, and permits)
- Chain of custody and point of origin documentation
- ODS composition and quantity lab reports

See section 95976 for regulatory record-keeping requirements.

7.3 Verification Cycle

Project verification schedules can be found in the Regulation.

8 Regulatory Verification Requirements

All Offset Project Data Reports are subject to regulatory verification as set forth in the Regulation by an ARB accredited verification body. The Offset Project Data Reports

must receive a positive or qualified positive verification statement to be issued ARB or registry offset credits.

9 Glossary of Terms[16]

Certificate of Destruction	An official document provided by the destruction facility certifying the date, quantity, and type of ODS destroyed.
Project commencement	The date of the beginning of the destruction activity.
Commercial refrigeration equipment	The refrigeration appliances used in the retail food, cold storage warehouse or any other sector that requires cold storage. Retail food includes the refrigeration equipment found in supermarkets, grocery and convenience stores, restaurants, and other food service establishments. Cold storage includes the refrigeration equipment used to house perishable goods or any manufactured product requiring refrigerated storage.
Container	An air- and water-tight unit for storing and/or transporting ODS material without leakage or escape of ODS.
Destruction	Destruction of ozone depleting substances by qualified destruction, transformation or conversion plants achieving greater than 99.99% destruction and removal efficiency, in order to avoid their emissions. Destruction may be performed using any technology, including transformation, that results in the complete breakdown of the ODS into either a waste or usable by-product.
Destruction facility	A facility that destroys, transforms or converts ozone depleting substances using a technology that meets the standards defined by the UN Environment Programme Technology and Economic Assessment Panel Task Force on Destruction Technologies as provided in the *Report of the Task Force on Destruction Technologies* and listed in The Climate Action Reserve's *U.S. Ozone Depleting Substances Project Protocol Version 1.0.*

[16] For terms not defined in this section, the definitions in the Regulation apply.

Emission rate	The rate at which refrigerant is lost to the atmosphere, including emissions from leaks during operation and servicing events.
Ozone Depleting Substances (ODS)	Ozone depleting substances are substances known to deplete the stratospheric ozone layer. The ODS controlled under the Montreal Protocol and its Amendments are chlorofluorocarbons (CFC), hydrochlorofluorocarbons (HCFC), halons, methyl bromide (CH_3Br), carbon tetrachloride (CCl_4), methyl chloroform (CH_3CCl_3), hydrobromofluorocarbons (HBFC) and bromochloromethane (CHBrCl).
Recovery efficiency	The percent of total ODS blowing agent that is recovered during the process of ODS blowing agent extraction.
Recharge	Replenishment of refrigerant agent (using reclaimed or virgin material) into equipment that is below its full capacity because of leakage or because it has been evacuated for servicing or other maintenance.
Reclaim	Reprocessing and upgrading of a recovered ozone depleting substance through mechanisms such as filtering, drying, distillation and chemical treatment in order to restore the ODS to a specified standard of performance. Chemical analysis is required to determine that appropriate product specifications are met. Reclaiming and the associated chemical analysis often involve processing off-site at a central facility.
Recovery	The removal of ozone depleting substances from machinery, equipment, containment vessels, etc., during servicing or prior to disposal without testing or processing it in any way.
Reuse/recycle	Reuse of a recovered ozone depleting substance following a basic cleaning process such as filtering and drying. For refrigerants, recycling normally involves recharge back into equipment and it often occurs 'on-site'.
Startup, shutdown, and malfunction plan	A plan, as specified under 40 CFR 63.1206, that includes a description of potential causes of malfunctions, including releases from emergency

	safety vents, that may result in significant releases of hazardous air pollutants, and actions the source is taking to minimize the frequency and severity of those malfunctions.
Stockpile	ODS stored for future use or disposal in bulk quantities at a single location. These quantities may be composed of many small containers or a single large container.
Substitute refrigerant	Those refrigerants that will be used to fulfill the function that would have been filled by the destroyed ODS refrigerants. These refrigerants may be drop-in replacements used in equipment that previously used the type of ODS destroyed or may be used in new equipment that fulfills the same market function.
Substitute emissions	A term used in this protocol to describe the greenhouse gases emitted from the use of substitute refrigerants in technologies that are used to replace the ODS destroyed in a project.
Transportation system	A term used to encompass the entirety of the system that moves the ODS from the point of aggregation to the destruction facility.

10 References

CAR (2010) U.S. Ozone Depleting Substances Project Protocol Version 1.0. February 3, 2010.
http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

CAR (2010) U.S. Ozone Depleting Substances Project Protocol Errata and Clarifications. May 7, 2010.
http://www.climateactionreserve.org/how/protocols/adopted/ods/current/ (accessed August 30, 2010)

Appendix A Foam Recovery Efficiency and Calculations – Quantification Methodology

The following methodology calculates the site- or process-specific recovery efficiency for blowing agent recovery projects, and uses this value for calculation of GHG emission reductions in Section 5. Determination of accurate recovery efficiency allows project baseline emissions and project emissions to be calculated in reference to the initial quantity of foam blowing agent diverted from project baseline treatment.

A.1 Calculating Recovery Efficiency

All appliance foam projects must calculate a recovery efficiency based on a run of a minimum ten appliances. Basing this analysis on a number of appliances greater than ten will likely result in a higher calculated recovery efficiency due to the 90% upper confidence limit used for calculating the concentration of ODS blowing agent in the foam. A larger sample size will decrease uncertainty and thus lower the estimated blowing agent concentration and increase recovery efficiency; however, sampling of additional appliances will also increase testing costs.

The procedures below shall be used to calculate recovery efficiency.

Estimate initial blowing agent concentration

The concentration of ODS blowing agent in the PU foam prior to any appliance treatment shall either be assumed to equal to 14.9% or calculated according to the steps below. Calculating a sample-specific value allows the Offset Project Operators or Authorized Project Designees to document a lower ODS blowing agent concentration, which will result in a higher estimated recovery efficiency.

The following steps shall be followed to document a sample-specific ODS blowing agent concentration:

1. Cut four PU foam samples from each appliance (left side, right side, top, bottom) using a reciprocating saw. Samples must be at least four inches square and the full thickness of the insulation.
2. Seal the cut edges of each foam sample using aluminum tape or similar product that prevents off-gassing.
3. Individually label each sample to record appliance model, and site of sample (left, right, top, or bottom)
4. Analyze samples according to the procedures dictated for building foam in Section 6.3. Samples may be analyzed individually (four analyses per appliance), or a single analysis may be done using equal masses of foam from each sample (one analysis per appliance).
5. Based on the average of the samples for each appliance, calculate the 90% upper confidence limit of the concentration. The 90% upper confidence limit shall be used as the parameter BA_{conc} in the equations below.

Extract the ODS blowing agent and separate foam residual

The ODS blowing agent from the sampled appliances must be collected and quantified according to the steps below.

1. Begin processing with all equipment shut down and emptied of all materials.
2. Process all sample appliances.
3. Extract and collect concentrated BA. The mass of the recovered blowing agent shall be determined by comparison of the mass of the fully evacuated receiving containers to their mass when filled. This value shall be used as the parameter BA_{post} in the equations below.

Separate foam residual

The quantity of foam in the processed appliances must be established either through use of a default value of 12.9 pounds per appliance, or according to the following steps. If the value of 12.9 pounds per appliance is used, it shall be multiplied by the number of appliances processed to determine $Foam_{res}$ in the calculation of recovery efficiency.

1. Separate and collect all foam residual, which may be in a fluff, powder, or pelletized form. Processes must be documented to demonstrate that no significant quantity of foam residual is lost in the air or other waste streams.
2. If desired, manually separate non-foam components in the residual (e.g., plastic) to determine a percent of foam in residual. If performed, this analysis must be conducted on at least one kilogram of residual, and results may be no lower than 90%.
3. Weigh the total recovered foam residual, and, if performed, multiply by the percent foam in residual, to calculate total mass of foam recovered. This value shall be used as the parameter $Foam_{res}$.

Calculate recovery efficiency

To calculate the recovery efficiency, apply the calculated values to the equations below. The recovery efficiency (RE) calculated below shall be used in the calculations of Section 5.

$$BA_{init} = \frac{Foam_{res}}{(1 - BA_{conc})} \times BA_{conc}$$

Where,			Units
$Foam_{res}$	=	Mass of foam recovered	lbs foam
BA_{conc}	=	Initial concentration of blowing agent in PU foam	lbs BA / lbs PU
BA_{init}	=	Initial quantity of blowing agent in appliances prior to treatment	lbs BA

$$RE = \frac{BA_{post}}{BA_{init}}$$

Where,

			Units
RE	=	Recovery efficiency	%
BA_{post}	=	Quantity of recovered blowing agent in concentrated form	lbs BA
BA_{init}	=	Initial quantity of blowing agent in appliances prior to treatment	lbs BA

Appendix B Emission Factor Tables

Table B.1. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable).
Heat content factors are based on higher heating values (HHV).

Table B.2. CO_2 Electricity Emission Factors

eGRID subregion acronym	eGRID subregion name	Annual output emission rates	
		(lb CO_2/MWh)	(metric ton CO_2/MWh)*
AKGD	ASCC Alaska Grid	1,232.36	0.559
AKMS	ASCC Miscellaneous	498.86	0.226
AZNM	WECC Southwest	1,311.05	0.595
CAMX	WECC California	724.12	0.328
ERCT	ERCOT All	1,324.35	0.601
FRCC	FRCC All	1,318.57	0.598
HIMS	HICC Miscellaneous	1,514.92	0.687
HIOA	HICC Oahu	1,811.98	0.822
MROE	MRO East	1,834.72	0.832
MROW	MRO West	1,821.84	0.826
NEWE	NPCC New England	927.68	0.421
NWPP	WECC Northwest	902.24	0.409
NYCW	NPCC NYC/Westchester	815.45	0.370
NYLI	NPCC Long Island	1,536.80	0.697
NYUP	NPCC Upstate NY	720.80	0.327
RFCE	RFC East	1,139.07	0.517
RFCM	RFC Michigan	1,563.28	0.709
RFCW	RFC West	1,537.82	0.698
RMPA	WECC Rockies	1,883.08	0.854
SPNO	SPP North	1,960.94	0.889
SPSO	SPP South	1,658.14	0.752
SRMV	SERC Mississippi Valley	1,019.74	0.463
SRMW	SERC Midwest	1,830.51	0.830
SRSO	SERC South	1,489.54	0.676
SRTV	SERC Tennessee Valley	1,510.44	0.685
SRVC	SERC Virginia/Carolina	1,134.88	0.515

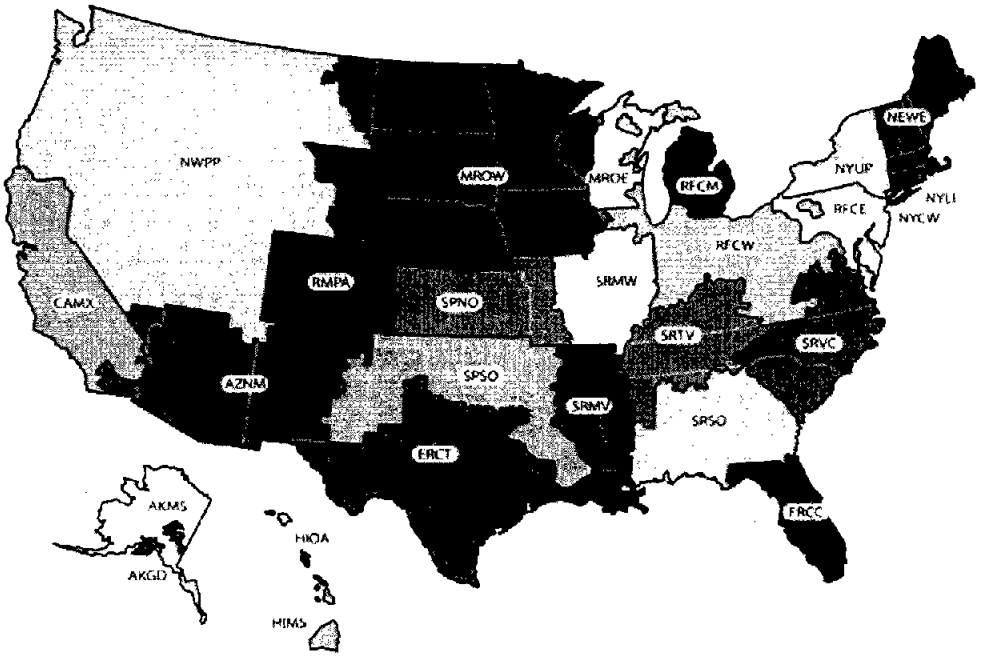


Figure B.1. Map of eGRID2007 Subregions

Appendix C Offset Project Listing Information

1. Offset project Name
2. Offset Project Operator or Authorized Project Designee
3. Technical Consultants
4. Other parties with a material interest
5. Date of form completion
6. Form completed by (name, organization)
7. Offset project Description: 1-2 paragraphs
8. List all points of origin by US state for ODS sourced for this project
9. All ODS sources that will be destroyed under this project:
   Refrigerant Destruction: CFC-11, CFC-12, CFC-113, CFC-114, or CFC-115
   Destruction of ODS Blowing agent in intact building foam: CFC-11, CFC-12, HCFC-22, HCFC-141b
   Destruction of concentrated ODS blowing agent in appliance foam: CFC-11, CFC-12, HCFC-22, HCFC-141b
10. Name of destruction facility
11. Address of destruction facility
12. Is the destruction facility a RCRA permitted hazardous waste combustor (HWC)?
13. If the destruction facility is not a RCRA-permitted HWC, has it met the TEAP requirements for ODS destruction?
14. Offset project commencement date
15. Reporting period
16. Have any GHG reductions associated with the offset project ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing? If yes, identify the registry or program (Vintage and reporting period)
17. Is this offset project being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate? If yes, explain.
18. Has an Offset Project Data Report been developed? If not, what date will it be in place?
19. Has the offset project-specific recovery efficiency been determined (for appliance foam projects only)? If not, when will this factor be established? If yes, what is the factor?
20. Was, or will, any of the destroyed ODS be sources from the US government? If yes, how much?
21. Was, or will, any of the destroyed ODS be considered hazardous waste under US, state or local law? If yes, how much and explain.

Appendix D Offset Data Report Information

1. Offset project name
2. Offset Project Operator or Authorized Project Designee
3. Report date
4. Contact information for Offset Project Operator or Authorize Project Designee
    a. Address, email, phone number
5. Name of individual completing report
6. Reporting Period
7. Does offset project meet all local, state, or federal regulatory requirements?
8. Date(s) of ODS destruction
9. Destruction facility name and location
10. Type of ODS destroyed
11. Mass and composition of ODS as determined by the process outlined in Section 6.6 of the Protocol.
12. Names of all parties and their contact information included in the chain of custody documentation
13. Is all the information in the offset project listing still accurate? If not provided updates.
14. Project baseline emissions
15. Project emissions
16. Total GHG reductions

October 2011



California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol Urban Forest Projects

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

ARB	California Air Resources Board
C	Carbon
CAR	Climate Action Reserve
CH_4	Methane
CO_2	Carbon dioxide
dbh	Diameter at breast height
GHG	Greenhouse gas
lb	Pound
N_2O	Nitrous oxide
NTG	Net tree gain
Regulation	Cap-and-Trade Regulation, title 17, California Code of Regulations, sections 95800 et seq.
TMP	Tree maintenance plan
USFS	United States Forest Service

1 Introduction

The Compliance Offset Protocol Urban Forest Projects provides methods to quantify and report greenhouse gas (GHG) removal enhancements associated with a planned set of tree planting and maintenance activities to permanently increase carbon storage in trees. This protocol is based on The Climate Action Reserve's Urban Forest Project Protocol Version 1.1[1] (CAR 2010).

Offset Project Operators or Authorized Project Designees that implement tree-planting programs must use this protocol to quantify and report GHG removal enhancements. The protocol provides eligibility rules, methods to quantify GHG removal enhancements, offset project-monitoring instructions, and procedures for reporting Offset Project Data Reports. Additionally, all offset projects must submit to independent verification by ARB-accredited verification bodies at least once every six years. Requirements for verification bodies to verify offset project emissions data reports are provided in the Cap-and-Trade Regulation (Regulation).

To register urban forest project GHG removal enhancements, Offset Project Operators and Authorized Project Designees are not required to prepare and submit an annual municipal, campus, or utility-level GHG inventory.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification of GHG emission reductions associated with urban forest projects. The protocol is comprised of both quantification methodologies and regulatory program requirements to develop an urban forest project and generate ARB or registry offset credits.

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[2]; 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 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] Climate Action Reserve (2010) Urban Forest Project Protocol Version 1.1 March 10, 2010 http://www.climateactionreserve.org/how/protocols/adopted/urban-forest/current-urban-forest-project-protocol/ (accessed May 20, 2011).

[2] Health and Safety Code section 38571.

2 The GHG Reduction Project

2.1 Project Definition – Quantification Methodology

For the purpose of this protocol, the GHG reduction ("removal enhancement") project is defined as a planned set of tree planting and maintenance activities that permanently increase carbon storage, taking into account GHG emissions associated with planting and maintenance of project trees.

While project trees are planted for the purposes of the urban forest GHG project, tree sites are the primary unit of analysis. A tree site contains one tree at a time, however, the tree may be replaced over time and the site itself may be moved. This is because project trees are subject to mortality and other types of losses and therefore may need to be replaced and/or relocated during the offset project life (see Section 6 for details).

This protocol is not applicable for forest management and conservation activities that occur on large natural forested tracts within cities (≥ 100 acres contiguously forested and containing dead downed woody material).

An Offset Project Operator or Authorized Project Designee can assemble several smaller offset projects into a single offset project for the purposes of achieving economies of scale and more efficient reporting. However, reporting, monitoring, and verification practices must follow the requirements set forth in this protocol and the Regulation.

This protocol is applicable to three specific project types: urban forest GHG projects undertaken (1) in municipalities[3], (2) on educational campuses[4], and (3) by utilities. An offset project is defined by a specific number of project tree sites, determined a priori, that will be planted and maintained within one of the above types of entities over the offset project life. If the Offset Project Operator or Authorized Project Designee intends to plant more project tree sites than the number defined under the original offset project, this constitutes a second, distinct urban tree project. Offset Project Operators or Authorized Project Designees can undertake as many urban tree projects as desired in the future as long as they each, separately, meet the eligibility criteria and reporting requirements in this protocol and set forth in the Regulation.

2.2 Offset Project Operator or Authorized Project Designee

The Offset Project Operator or Authorized Project Designee is responsible for offset project listing, monitoring, reporting and verification. The Offset Project Operator or Authorized Project Designee must have legal authority to implement the offset project. For the purpose of this protocol, an Offset Project Operator or Authorized Project

[3] Including cities, counties, and other local agencies or special districts.

[4] As noted in Section 4, the physical area owned and/or controlled by the municipality, educational campus, or utility determines municipal, campus, or utility service area boundaries. In the case of educational campuses, the Offset Project Operator or Authorized Project Designee may define the entity as a single campus or a system of campuses, as long as the definition is clearly stated and the entity can demonstrate that it has ownership and/or control over the physical area.

Designee must represent a municipality, educational institution, or utility. The Offset Project Operator or Authorized Project Designee must submit the information in Appendix C along with the listing requirements in the Regulation. Responsibility for tree planting, care, and maintenance activities may reside with either the Offset Project Operator or Authorized Project Designee.

3 Eligibility Rules

General eligibility requirements for offset projects are set forth in the Regulation. The Offset Project Operator or Authorized Project Designee using this protocol must also satisfy the following rules to be eligible to receive ARB or registry offset credit.

3.1 Location

Only offset projects located in the United States and its territories are eligible under this protocol. In addition, 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) in 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.

Project tree sites must be located according to the requirements in Section 4 (average spacing of no less than 5 meters and placement along streets, in parks and parking lots, etc.) Thus, urban forest projects must take place in urban or other types of developed areas.

3.2 Offset Project Commencement

Offset Project Commencement for an urban forest project is defined as the date at which the Offset Project Operator or Authorized Project Designee implements a planned set of tree planting activities and becomes operational. For the purposes of this protocol, the commencement of operation means when trees are planted and regular maintenance begins. Offset projects may always be submitted for listing prior to their commencement date.

3.3 Project Crediting Period

The crediting period for this project type is 25 years. Requirements for renewal of offset project crediting periods are set forth in the Regulation.

3.4 Additionality

Offset projects must meet the additionality requirements in the Regulation, in addition to the requirements below.

3.4.1 Net Tree Gain – Quantification Method

The offset project must demonstrate a priori that it will exceed the business-as-usual threshold, and information confirming this, in accordance with the requirements below, must be provided in the documentation for applying for offset project listing as set forth in Appendix C.

The business-as-usual threshold comparison for municipalities, educational campuses, and utilities is based on information within the area the offset project will take place. If a partner organization/individual working with a municipality, educational campus, or utility plants trees outside the offset project boundary, these activities should not be included in the comparison.

Municipalities and Educational Campuses

The business-as-usual thresholds for municipalities and educational campuses are measured in terms of net tree gain (NTG), i.e., the annual number of trees planted by a municipality or educational campus minus the annual number of trees removed by a municipality or educational campus. Only project activities that exceed this threshold are eligible.

The threshold for municipalities and educational campuses is set at maintaining a stable urban forest population (i.e. a NTG of 0). In other words, municipalities and educational campuses must plant at least as many trees as they remove.

In addition to the requirements for offset project listing, the Offset Project Operator or Authorized Project Designee must demonstrate a priori that an offset project will exceed the threshold, by calculating the anticipated NTG of the municipality, or educational campus, based on recent activities and anticipated project activities. Specifically, the calculation must be based on:

1. The annual average number of urban trees planted and removed in the municipality or educational campus over no more than the most recent five year period preceding the offset project commencement date, or using data from a single year occurring at some point during the past most recent five year period.
2. The expected average annual number of GHG project tree sites to be planted by the offset project.
3. Where urban trees include trees under municipality or educational campus ownership or control and are open-grown in managed landscapes.

In addition to the general requirements for monitoring, reporting, and record retention set forth in the Regulation, for each year of the offset project the Offset Project Operator or Authorized Project Designee is required to report an annual average NTG (number of urban trees planted minus removed) for the municipality, or educational campus, including regular activities (planting of "non-project" trees) and project activities (planting of "project" trees). The annual average NTG must be based on a five-year rolling average (i.e. the most recent previous five years including the reporting year), except in

the first five years of the offset project when the average may be based on less than five years of data (i.e. one-year average in the first year of the offset project, two-year average in the second year). When the average annual NTG for the municipality or educational campus is positive (more trees are planted than removed), the number of trees planted in excess of the number removed determines how many eligible project trees can be designated that year. Specific eligible project trees are identified each year by the Offset Project Operator or Authorized Project Designee and tracked individually for the duration of the offset project. Carbon sequestration and GHG emissions from tree care, monitoring, and maintenance of the eligible project trees are the basis for calculating offset project GHG reductions.

If the municipality or educational campus reports a negative NTG in any given year, no new trees planted that year can be considered eligible project trees and no ARB or registry offset credits can be issued. When the municipality or educational campus returns to an average annual NTG of zero or greater, ARB or registry offset credits for GHG reductions from project trees during the intervening years (up to a maximum of five years) can be issued ex-post upon verification, as long as the criteria in this protocol for project trees were met during those years.

Utilities

Most utilities do not have tree planting programs that go beyond replacing trees removed during line clearance operations. While some have programs specifically aimed at storing carbon and conserving energy in residential households, on average utilities are planting fewer than 400 trees annually in these types of programs. All trees planted under these types of programs are considered additional and therefore are designated as eligible project trees. These trees may be used to generate GHG reductions, provided all criteria in this protocol and the regulation are met.

3.5 Regulatory Compliance

Offset Project Operators or Authorized Project Designees must fulfill all applicable local, regional and national requirements for environmental impact assessments that apply based on the offset project location. Offset projects must also meet all other local, regional, and national requirements that might apply. Offset projects are not eligible to receive ARB or registry offset credits for GHG emission reductions or GHG removal enhancements that occur as the result of activities that are not in compliance with regulatory requirements.

4 Offset Project Boundary – Quantification Methodology[5]

The Offset Project Boundary delineates the GHG sources, GHG sinks, and GHG reservoirs that are considered significantly affected by the project activity and must be included in the calculation of GHG reductions.

In this protocol, the Offset Project Boundary is defined as the carbon stored in standing trees and GHG emissions from motor vehicles and equipment used in tree care activities.

Required GHG source and GHG sink categories for reporting are as follows:

- Carbon stored in standing trees
- CO_2 emissions from motor vehicles related to tree planting, care, and monitoring
- CO_2 emissions from equipment related to tree planting and care

CO_2 is the primary GHG to report for urban forest projects.

The Offset Project Boundary includes the components of the project operations that are impacted by the project activity, including the physical area covered by the offset project as well as the specific equipment used by the offset project. This includes:

- The number of eligible project tree sites (determined in Section 3)
- Equipment used to plant and maintain the trees

Tree sites must be located within the boundary of a municipality, educational institution, or utility. Boundaries are determined by the physical area owned and/or controlled by a municipality or educational campus, or the service area covered by a utility.

For each offset project, eligible project trees must be planted:

- Along streets, in parks, city golf courses, cemeteries, near city buildings, greenbelts, city parking lots, and other public open space, or on private property in municipalities
- Along streets, near classrooms, dorms, office buildings, near recreational fields and other facilities, in parking lots, arboretums, and other open space on educational campuses
- In parks, streets, parking lots, private property, and open spaces by utilities

Tree plantings must have an average spacing of no less than 5 meters. Biomass equations for estimating carbon stock changes are for open-growing urban trees and assume relatively intensive management. The spatial location of all project tree sites must be known and recorded using GPS or GIS.

[5]The entirety of Chapter 4 is considered a quantification method.

4.1 Leakage

Leakage is an increase in GHG emissions or decrease in sequestration caused by the offset project but not accounted for within the offset project boundary. In the case of urban forest projects, the most likely form of leakage is the shifting of funds and maintenance from non-project tree resources (i.e. trees within the municipality, educational campus, or utility service area that are not part of the project) to project trees within a municipality, educational campus, or utility service area. For example, if funding is reduced for pruning existing trees to fund a GHG tree planting project, there may be an overall decline in the health of the urban forest within a municipality, educational campus, or utility service area and a long-term increase in mortality. A tree maintenance plan (TMP) is used to assess whether this type of activity-shifting leakage is occurring. Details on the TMP requirements are provided in Section 8.1. If annual expenditures of the municipality, educational campus, or utility (separate from offset project expenditures) in one or more program areas decrease by more than 10% from amounts in the initial TMP or from amounts in the previous year TMP, and these changes cannot be explained by the Offset Project Operator or Authorized Project Designee to the verifier, leakage will be assumed and if confirmed, no ARB or registry offset credits can be issued in that year.

5 GHG Calculation Methods – Quantification Methodology[6]

This section provides the detailed methods for calculating GHG emissions and GHG removals enhancements from the required GHG sources and GHG sinks:

- Carbon storage in standing trees: *Project Tree CO_2 Sequestration*
- GHG emissions from motor vehicles related to tree planting, care, and monitoring: *Vehicle CO_2 Emissions*
- GHG emissions from equipment related to tree planting and care: *Equipment CO_2 Emissions*

Project GHG reductions (removal enhancements) are based on the amount of carbon sequestered in eligible project trees minus GHG emissions from the planting, care and maintenance of those trees over the reporting period. Below is the general formula for determining project GHG reductions.

Project GHG Reductions =	*Project Tree CO_2 Sequestration – Vehicle CO_2 Emissions – Equipment CO_2 Emissions*

5.1 Quantifying Project Tree CO_2 Sequestration

For each crediting period, the Offset Project Operator or Authorized Project Designee estimates the amount of carbon contained in eligible project trees (carbon stocks) and then uses these data to calculate an incremental carbon stock change (carbon sequestration). Carbon stock changes are reported in final units of carbon dioxide equivalent (metric tons CO_2e). The change in carbon stocks (in kilograms) is the basis for estimating project tree carbon sequestration, and is calculated using the equation below. The factor 3.67 is the molecular weight ratio of CO_2 to carbon and is used to convert carbon stock change to CO_2. The factor 0.001 is used to convert the result from kilograms to metric tons.

$$\textit{Project Tree } CO_2 \textit{ Sequestration} = (Cstock_{year\ x} - Cstock_{year\ x\text{-}n}) \times (3.67) \times 0.001$$

5.1.1 Quantifying Tree Carbon Stocks

Quantifying the carbon stocks in eligible project trees is based on direct measurements of trees and approved urban tree carbon models ("allometric equations"). Consult Appendix A and Appendix B for detailed requirements.

Appendix A covers how to design tree measurement programs (inventories), including required tree measurement data and sampling techniques, design, and error. Appendix B describes how to estimate tree carbon from tree measurement data using allometric equations.

[6] The entirety of Chapter 5 is considered a quantification method.

Approved approaches for quantifying carbon stocks:

1. Measure all trees in project tree sites during a single year (census). Use the measurement data with approved allometric equations (Appendix B) to estimate tree volume, biomass, and carbon stocks. Data from direct tree measurements (i.e. tree dbh, diameter at breast height, and height if applicable) can be input directly into approved allometric equations.

2. Measure a sample of trees in the project tree population each year (Appendix A), use the measurement data with approved allometric equations to estimate carbon stocks in the samples (Appendix B), and extrapolate the carbon stock estimates to the entire tree population (Appendix A). As described above in Approach 1, direct measurement must be used to estimate tree carbon stock.

5.1.2 Requirements for Tree Monitoring and Acceptable Levels of Uncertainty

In addition to the general requirements for monitoring, reporting, and record retention set forth in the Regulation, a tree monitoring plan must be included as part of the offset project documents (see Section 7.2 for details). The tree monitoring plan must describe in detail the approach the offset project plans to use to quantify carbon stocks. The document will serve as evidence for the Offset Project Operator or Authorized Project Designee and will communicate the methodology to the verification body.

Approach 2 involves statistical extrapolation from sample data. The sampling method must be stratified by like-species and age classes (not to exceed groupings of five-year age classes). The combinations of species and age classes create independent sampling populations, or strata. Appendix A provides further details on stratified sampling design.

The resulting estimates must meet a minimum confidence level of 90% to report all of the estimated carbon stocks. If the project sampling design results in lower levels of confidence, the carbon stock estimates will be discounted according to the method below. See Appendix A for details on-sampling programs.

Descriptive statistics must be produced at the time of verification if a sampling methodology is incorporated. The estimate of carbon stock change in project trees is adjusted based on the level of confidence in the carbon stock estimate according to the table below. The table provides sampling error ranges (where sampling error is on either side of the mean estimate at the 90% confidence level), calculated with the following equation:

Sampling Error (90% confidence interval) =	*[(1 Standard Error *1.645)/(Sample mean)] x 100*

Table 5.1. Sampling Error and Carbon Stock Change Adjustment

Sampling Error*	Carbon Stock Change Adjustment (deduction by)
0 to 5%	0%
5.1 to 10%	10%
10.1 to 15%	20%
15.1 to 20%	30%
> 20%	100%

* Minimum confidence interval at 90% confidence limits.

5.2 Quantifying GHG Emissions from Motor Vehicles Related to Tree Planting and Care

Vehicle emissions are those associated with transport of personnel, supplies, and trees to and from eligible project tree sites.

Calculations of CO_2 emissions from vehicles are based on actual fuel use (gallons per year) and an emission factor (kg CO_2 per gallon) for fuel.

$C_{vehicle\ emis} = TC \times EF$

Where,

TC = Total annual fuel consumption (gallons)
EF = Emission factor by fuel type. Divide by 1,000 to convert kilograms into metric tons (t).

See the CO_2 emission factors for fuel combustion in the table below.

Table 5.2. Carbon Dioxide Emission Factors for Fuels

Fuel	CO_2 Emission Factor (kg CO_2/gallon)
Aviation Gasoline	8.31
Biodiesel (B100)	9.45
Crude Oil	10.28
Diesel 1 Diesel 2 Diesel 4	10.18 10.21 10.96
Ethane	6.01
Ethanol (E100)	5.75
Isobutane	6.29
Jet Fuel (Jet A or A-1)	9.75
Kerosene	10.15
Liquefied Petroleum Gas (LPG)	5.79
Methanol	4.15

Motor Gasoline	8.78
n-Butane	6.58
Propane	5.59
Residual Fuel Oil (#5,6)	10.21, 11.27
	(kg CO_2/therm)
Natural Gas	5.30

Source: Federal Register, Vol. 74, No. 209 (October 30, 2009)

The volume of fuel consumed during the crediting period can be derived from fuel records data (including bulk fuel purchase records, collected fuel receipts, official logs of vehicle fuel gauges or storage tanks). Where actual fuel use (TC) is not available, it can be estimated using vehicle information (make, model, model year, and fuel type) and annual mileage estimates by vehicle type. For each vehicle, convert annual mileage to fuel consumption using EPA's fuel economy formula below. In this equation, DP_c and DP_h are the proportion of miles traveled spent in city and highway driving conditions, respectively. A DP_c value of 0.55 and a DP_h value of 0.45 may be used as a default value, or a fleet specific number may be substituted if known.

Total Fuel Use	=	Total Mileage	/ (	Fuel Economy City	x DP_c	+	Fuel Economy Highway	x DP_h	)
(gallons)		(miles)		(mpg)			(mpg)		

Alternatively, the amount of fuel used for the eligible project trees can be estimated by prorating total fuel usage for all tree maintenance and monitoring activities of the municipality, educational campus, or utility by the number of eligible project tree sites relative to total trees managed by the municipality, educational campus, or utility.

5.3 Quantifying GHG Emissions from Equipment Related to Tree Planting and Care

Equipment emissions are associated with back hoes used in planting, and chain saws, aerial lifts, and chippers used during tree removal and pruning activities.

If the total amount of fuel consumed by equipment on GHG project-related activities is known, CO_2 emissions can be calculated using fuel-specific emission factors in Table 5.2:

$$C_{equip\ emis} = TC \times EF$$

In many cases, equipment use is tracked in hours. If the hours are known, the emissions can be calculated for each piece of equipment based on the following formula and then summed:

$$C_{equip\ emis} = HRS \times LF \times HP \times EF$$

Where,

HRS = Hours used
LF = Typical load factor
HP = Maximum horsepower
EF = Average CO_2 emissions per unit of use (kg/hr)

Typical load factors, horsepower, average emissions, and EFs for equipment are given in Table 5.3. Typical hours required for pruning and removal activities are given for maintenance equipment in Table 5.4.

Table 5.3. Typical Load Factors (LF) and Average CO_2 Emissions (EF) for Maintenance Equipment

Equipment	HP range[b]	LF[a]	EF (kg/hp/hr)[b]
Aerial lift (45 hp)	25<HP≤50	0.505	0.783
Backhoe	HP≤120	0.465	0.775
Chain saw (2 hp)	HP≤2	0.500	0.429
Chain saw (7 hp)	2<HP≤7	0.500	0.429
Chipper (50 hp)	HP≤50	0.370	0.783

[a] Climate Action Reserve 2010, Section 6.3 pg 16.
[b] California Air Resources Board 2008

Table 5.4. Total Hours of Equipment Run-Time for Tree Pruning and Removal

	Pruning				Removal				
dbh	2.3-hp saw	3.7-hp saw	Bucket truck[a]	Chipper[b]	2.3-hp saw	3.7-hp saw	7.5-hp saw	Bucket truck	Chipper
1-6	0.05	NA	NA	0.05	0.3	NA	NA	0.2	0.1
7-12	0.1	NA	0.2	0.1	0.3	0.2	NA	0.4	0.25
13-18	0.2	NA	0.5	0.2	0.5	0.5	0.1	0.75	0.4
19-24	0.5	NA	1.0	0.3	1.5	1.0	0.5	2.2	0.75
25-30	1.0	NA	2.0	0.35	1.8	1.5	0.8	3.0	1.0
31-36	1.5	0.2	3.0	0.4	2.2	1.8	1.0	5.5	2.0
36+	1.5	0.2	4.0	0.4	2.2	2.3	1.5	7.5	2.5

[a] Mean HP = 43
[b] Mean HP = 99

Note: Values by dbh classes (inches) and assume crews work efficiently and equipment is not run idle.

Source: see references in CAR 2010.

5.4 Quantifying GHG Emissions from Vehicles and Equipment for Municipalities with Insufficient Data

In some instances, municipalities may not have the data necessary to calculate GHG emissions for tree planting and maintenance activities as required in Sections 5.2 and 5.3 (if, for instance, tree maintenance activities are contracted out to private entities). If data required to calculate CO_2 emissions from tree planting and maintenance activities is not obtainable, municipal projects may use a default emission factor equal to 4.17 kg CO_2 per project tree per year to calculate the annual CO_2 emissions from all, or a portion of, the tree planting and maintenance activities associated with a municipal urban forest project.[7] However, all offset projects must use the methods described in Sections 5.2 and 5.3 to assess CO_2 emissions from vehicles and equipment if there is sufficient data to do so. The metric listed above is based on survey results from municipal tree planting programs, and is thus only applicable to municipal urban forest projects.

[7] The default emission factor was derived from survey responses detailing annual fuel usage for the tree planting and maintenance activities of 30 municipal urban forest programs nation-wide. The default value is equal to one standard deviation above the mean of the data set.

6 Permanence

The Regulation requires that credited GHG reductions and GHG removal enhancements be "permanent." GHG offset projects involving biological carbon sequestration must address the potential reversibility of sequestered carbon, which is the loss of stored carbon after ARB or registry offset credits have been issued. Consistent with guidance from the Intergovernmental Panel on Climate Change, permanence is defined as 100 years - the biological carbon should remain stored for 100 years (e.g. a reduction of carbon created in 2010 will remain stored until 2110 and if it is reversed, e.g. through mortality, it must be replaced).

Project Life is defined as the period of time between offset project commencement and a period of 100 years following the issuance of any ARB or registry offset credit for GHG reductions or GHG removal enhancements achieved by the offset project. Urban forest offset projects must continue to monitor, verify and report project data for a period of 100 years following any ARB or registry offset credit issuance. For example, if ARB or registry offset credits are issued to an urban forest project in year 25 following offset project commencement, monitoring and verification activities must be maintained until year 125. Offset Project Operators and Authorized Project Designees must take steps to maximize the likelihood that the carbon gains of urban forest projects are preserved for the project life. To this end, the following are requirements of this protocol:

1. All offset projects must monitor onsite carbon stocks, submit annual Offset Project Data Reports, and undergo third-party verification of those reports with site visits at least once every six years for the duration of the Project Life.
2. Continuous replacement of dead project trees at all tree sites during the Project Life (i.e. projects must have an average net tree gain of no less than zero). Prior to removal, dead trees must be measured for dbh (and height, if applicable) and their carbon content calculated and recorded using procedures in Appendix B. Dead trees must be replaced within one year from when they were removed. This timeframe allows for planting to occur at the appropriate time of year (e.g. loss and removal may occur in the fall and replanting occurs in the spring). Each tree site may have one or more replacement trees over time. Also, the location of some GHG project tree sites may change due to disturbances that unexpectedly eliminate tree sites. It is the Offset Project Operator's or Authorized Project Designee's responsibility to promptly locate and plant replacement sites so that there is no reduction in the total number of treed project sites.
3. If reversals are not compensated for with replacement trees, ARB requires that GHG offset credits be retired in proportion to any reversals (i.e. the carbon lost, in CO_2 equivalents, from removed trees), such that the total number of issued ARB offset credits does not exceed the total quantity of carbon stored (in CO_2 equivalents) by a project since its commencement date.

7 Offset Project Monitoring – Quantification Methodology[8]

General requirements for monitoring, reporting, and record retention are provided in the Regulation. Offset Project Operators and Authorized Project Designees are responsible for monitoring the performance of the offset project and maintaining records of monitoring data in accordance with the Regulation as well as the requirements stipulated in Section 8 and Appendix D. Monitoring is required for the Project Life (a period of 100 years following the issuance of ARB or registry offset credits for quantified GHG reductions or GHG removal enhancements).

Monitoring requirements are divided into these categories:

- Tree maintenance plan
- Project tree monitoring plan
- GHG emissions and sequestration activity data

The tree maintenance plan (TMP) is used to assess the potential of leakage and other aspects of offset project performance. The tree monitoring plan and GHG emissions and sequestration activity data are used to verify GHG emissions and sequestration estimates.

7.1 Tree Maintenance Plan

Reporting planting and maintenance activities and expenditures is critical to assessing leakage and GHG tree project compliance. At the level of the municipality, campus, or utility, by comparing reported annual tree care expenditures for different years a verifier can assess if a boost in project activity coincides with a drop in the level of care non-project trees are receiving. At the project level, information about tree maintenance and expenditures helps assess the strength of the project and its likelihood of success. In addition, all tree planting and removal practices by the municipality, campus, or utility must be reported each year to determine the number of eligible project trees.

To standardize annual reporting of tree planting and maintenance operations, activities are grouped into five program areas: tree planting, young tree care (< 5 years), mature tree care (> 5 years), tree removal, and administration/other (e.g. clerical, training, outreach). Annual expenditures and the level of service provided are indicators for each program area. Level of service is a quantifiable measure of tree care activities performed during a year. Higher levels of service indicate greater amounts of work performed. Reporting municipalities, educational campuses, or utilities must provide a TMP that describes municipal, educational campus, or utility-level expenditures for a 10- to 20-year period and project level activities for the reporting period.

Below are the specific TMP requirements. All information is for GHG project activities and expenditures (i.e. those related to project trees), except where noted. In some cases, information about the municipality, educational campus, or utility is also required to assess leakage potential (i.e. activities and expenditures related to non-project trees).

[8] The entirety of Section 7 is considered a quantification method.

Where both project and municipal, educational campus, or utility-level information is required, this is denoted in parentheses. Otherwise the information pertains to the project only.

Note that the Offset Project Operator or Authorized Project Designees must report on the most recent annual levels and expenditures and estimate the anticipated annual levels and expenditures for each of the criteria below in the project listing form and maintain records on actual levels and expenditures each year for the Project Life.

Tree planting:

- Number of trees planted in new tree sites each year, not including replacement trees (total for the municipality, educational campus, or utility, including project and non-project trees).
- Number of trees planted to replace removed trees each year ("replacement trees"), including replacement trees planted in relocated tree sites (separately for non-project and project trees).
- Species, size, and location[9] of project trees planted in new tree sites each year.
- Species, size, and location9 of project replacement trees planted in existing or relocated tree sites each year.
- Number and location[9] of relocated project tree sites each year.
- Reasons for relocations and, if applicable, modifications made to the project to reduce the chance of future relocations.
- Project tree resource: percentage of total project tree sites now planted.
- Annual tree planting expenditure (separately for the project and for the municipality, educational campus, or utility).

Young tree care:

- Number of young project trees inspected/pruned each year.
- Inspection/pruning cycle (total number of project trees / number treated per year).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

Mature tree care:

- Number of mature project trees inspected/pruned each year.
- Inspection/pruning cycle (total number of project trees / number treated per year).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

Tree removal:

- Number of trees removed from existing tree sites each year (separately for non-project and project trees).
- Species, size, and location[9] of project trees removed each year.
- Reasons for removals and, if applicable, modifications made to the project to reduce the chance of future removals.

[9] Tree site location must be designated on a map of the project physical boundaries.

- Removal cycle (total number of project trees to remove / number removed per year).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

Administration/other:

- Average $/tree site expenditure (total $ on admin and other / total tree numbers) (separately for the project and municipality, educational campus, or utility).
- Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

If the potential for leakage is determined, the Offset Project Operator or Authorized Project Designee must explain to the verifier the changes in expenditures. Additional information on municipal, educational campus, or utility-level tree planting activities may be requested by the verification body.

7.2 Project Tree Monitoring Plan

A Project Tree Monitoring Plan is important for several reasons. The plan provides sufficient and transparent information on tree measurement and monitoring. This information is used to ensure the quantification methods meet the standards of this protocol. In addition, the plan informs the offset project about the status of tree sites, helping to ensure that lost trees are replaced and risks of reversals are minimized. The items below must be included in a project tree monitoring plan. For further technical information on urban forest inventory and monitoring, consult Appendix A.

- Choice of method from the options in Section 5.1.
- Detailed description of procedures to census (or sample, if applicable), measure, and report information on the project trees, including the survey method, sample sizes, and method for choosing samples.
- Methods used to measure and record tree size.
- Methods used and information collected on tree survival and health.
- Statistical methods used to extrapolate sample data to the total project tree population, if applicable.
- Estimated sampling error, if applicable.

7.3 GHG Emissions and Sequestration Activity Data

The data below are required inputs for estimating project GHG reductions. Transparent reporting of this information assists with verification of the project.

- Data on the species, dimensions (including dbh), date of measurement, and location of measured trees.
- Specific equations used to calculate tree volume, biomass and carbon content.
- Make and model year, annual amount and type of fuel used by tree planting and care vehicles (or the vehicle miles traveled and average fuel economy).

- Equipment type, horsepower rating, annual amount and type of fuel consumed in tree maintenance equipment (or the number of hours equipment is used).

8 Reporting Parameters

General requirements for monitoring, reporting, and record retention are included in the Regulation. This section provides requirements on additional reporting and procedures specific to this protocol.

8.1 Annual Reporting Requirements

The Offset Project Operator or Authorized Project Designees must submit an Offset Project Data Report according to the requirements in the Regulation. The Offset Project Data Report must include the information listed in the Regulation and this protocol and cover a single reporting period. See the Regulation and Appendix D for specific requirements.

All reports must be submitted after a review by a Professional Urban Forester. If the offset project is located in a jurisdiction without a Professional Urban Forester law or regulation, then a Professional Urban Forester must either have a Certified Forester credential managed by the Society of American Foresters, or any one of the following: California Certified Urban Forester credential managed by the California Urban Forests Council, Certified Arborist credential managed by the International Society of Arboriculture, Registered Consulting Arborist credential managed by the American Society of Consulting Arborists, or any other valid professional Forester, Arborist, Landscape Contractor, Landscape Architect, or Planner license or credential, approved by a government agency in the jurisdiction where the project is located.

8.2 Document Retention

The Offset Project Operator or Authorized Project Designee is required to retain all documentation and information outlined in the Regulation and in this protocol. Record retention requirements can be found in the Regulation.

Specific types of information the Offset Project Operator or Authorized Project Designee must retain includes but is not limited to:

- All data inputs for the calculation of vehicle and equipment fuel consumption and CO_2 emissions, tree carbon stocks, and project GHG reductions
- CO_2e tonnage calculations
- Initial and subsequent verification records and results
- Tree monitoring plan, and all tree maintenance plans and records relevant to the urban forest project

8.3 Verification Cycle

Offset project verification schedules are set forth in the Regulation.

9 Regulatory Verification Requirements

Regulatory verification requirements are set forth in the Regulation. In addition, each urban forest offset project verification team must include the following:

1. At least one Professional Urban Forester that takes an active role in reviewing the urban forest offset project tree biomass and carbon inventory, tree maintenance plan, tree monitoring plan, and conducting the site visit.
2. An ARB-accredited Forest or Urban Forest Offset Project Specialist.

An explanation demonstrating that the verification team includes individuals with the required experience and expertise must be included in the Notice of Verification Services submittal. The required experience and expertise may be demonstrated by a single individual, or by a combination of individuals.

During initial verification, the verification body must determine if the methodology in the Project Tree Monitoring Plan is acceptable and if it has sufficient detail for analysis during verification of the project.

10 Glossary of Terms[10]

GHG reservoir	GHG reservoir is defined in the Regulation. For urban forest projects, GHG reservoirs include above-ground or below-ground biomass or roots, litter, soil, bole, branches and leaves, among others.
Carbon sequestration	The removal and storage of carbon from the atmosphere in greenhouse gas sinks or greenhouse gas reservoirs through physical or biological processes The process by which trees remove carbon dioxide from the atmosphere and transform it into biomass.
Carbon stock	The quantity of carbon contained in a GHG reservoir. For this protocol, urban trees are carbon stocks.
Dry weight (DW) biomass	The weight of aboveground tree biomass when dried to 0% moisture content. Also known as oven-dry and bone-dry biomass. Convert from green biomass to dry weight biomass by multiplying by 0.56 for hardwoods or 0.48 for softwoods.
Freshweight or green biomass	The weight of aboveground tree biomass when fresh (or green), which includes the moisture present at the time the tree was cut. The moisture content of green timber varies greatly among different species. This protocol assumes that the moisture content of freshweight biomass is 30%.
Inherent uncertainty	For this protocol, the scientific uncertainty associated with calculating carbon stocks and greenhouse gas emissions.
Leakage	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. For this protocol, shifting of activities or resources *from* other parts of the

[10] For terms not defined in this section, the definitions in the Regulation apply.

	municipality, educational campus, or utility *to* the project, causing unanticipated increases in GHG emissions outside the project boundary.
Net tree gain (NTG)	Number of trees planted minus the number removed annually. NTG can be measured at the entity or project level.
Professional Urban Forester	A professional engaged in the science and profession of urban forestry. A Professional Urban Forester is defined as having any one of the following: Certified Forester credential managed by the Society of American Foresters; California Certified Urban Forester credential managed by the California Urban Forests Council; Certified Arborist credential managed by the International Society of Arboriculture; Registered Consulting Arborist credential managed by the American Society of Consulting Arborists; any other valid Forester, Arborist, Landscape Contractor, Landscape Architect, or Planner professional license or credential approved by a government agency in the jurisdiction where the project is located.
Project activity	The atmospheric CO_2 removal, carbon storage, GHG emission reductions and GHG emissions due to an urban forest tree project.
Project Life	Refers to the duration of an urban forest project and its associated monitoring and verification activities, as defined in Section 6.
Reporting uncertainty	The level of uncertainty associated with an entity's chosen method of sampling and/or inventorying carbon stock and calculation methodologies. Contrast with inherent uncertainty.
Tree Biomass	The amount of organic material comprising the above-ground (bole, stems and leaves) and below-ground (roots) components of a tree.
Tree maintenance plan (TMP)	Describes annual tree maintenance levels of service and associated expenditures.
Tree residue	Above-ground biomass from urban trees (as distinguished from construction debris) that can be salvaged for reuse, such as mulch, wood products, or fuel.
Tree resource	All trees planted and maintained by an entity.

11 References

Health and Safety Code, section 38571.

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Appendix A Urban Forest Inventories and Sampling – Quantification Methodology[11]

The Compliance Offset Protocol Urban Forest Projects requires collecting information about trees over time. This can be accomplished through field surveys, where it may not be practical to perform a complete inventory of every tree in the overall population. However, it is still possible to obtain reliable information about the overall population by collecting data from a representative subset or sample. Sampling is the technique used to choose representative units for study from a larger population. This appendix provides basic information about field survey and remote-sensing approaches, inventories and sampling, and lists additional resources.

A.1 Options for Data Collection

A.1.1 Field Surveys

Field or ground surveys can provide high quality data on individual trees if inspectors are well-trained and motivated. For example, tree dbh can be directly measured for use in biomass equations. Urban tree inventory includes locating the tree using a Global Positioning System (GPS), collecting relevant data, delivery of a database, and reporting findings. During a field survey information on the condition and management needs of each tree can be collected. These data may trigger actions that will improve tree growth and survival.

A.2 Complete Inventory

A complete inventory will always provide the most accurate assessment of the tree population. Typically the only bias introduced is from measurement inaccuracies. Establishing measurement protocols, training data collectors, and performing regular quality control assessments should limit this error.

The primary questions to answer when conducting both complete inventories and sampling are 1) what data are necessary to collect, 2) how should these data be recorded – on paper or electronically, and 3) what margin of error is acceptable for samples? The first two questions are data collection issues and are addressed in this section. The third question is a data analysis issue and will be addressed in the sampling section of this appendix.

A.2.1 Inventory Systems

There are numerous urban tree inventory systems available to consumers ranging from freeware to software packages requiring fee-for-service support. See the Climate Action Reserve Urban Forest Project Protocol, version 1.1, 2010 for guidance on inventory systems.

A.2.2 What to Record

For assessing and monitoring carbon stocks, any database associated with an inventory system must be capable of producing the reports required for project reporting. Table A.1 shows an example list of key data fields, drawn from the i-Tree software suite developed by the USDA

[11] The entirety of Appendix A is considered a quantification method.

Forest Service as an inventory and reporting tool. More detailed components are listed in the users guide available at http://www.itreetools.org.

Table A.1. Example of Common Data Fields for Tree Inventorying

Data Field	Description	Purpose
Tree Id	unique tree identifier	tree location
Zone	alphanumeric code/name showing management area or zone where tree is located	area/zone comparisons or sampling areas
Street Segment	numeric code used with STRATUM sampling program	used in sampling to predict population by dbh classes
City Managed	numeric code showing city or private tree ownership	asset value, structure
Species Code	alphanumeric code denoting genus and species	species and tree count,
Land Use	numeric code for landuse types (e.g., single family residential, commercial, park)	may assist in stratified sampling
Loc Site	numeric code for tree site (e.g., front lawn, planting strip, median, cutout)	tree location info, stratified sampling, energy benefits
DBH	numeric code for diameter-at-breast-height	growth, structure, age, carbon storage, annualization, costs
Mtce Recommendation	numeric code for recommended mtce (e.g., young tree, mature tree)	tree health,mortality, pruning needs assessments
Priority Task	numeric code for highest priority task to perform on tree	tree health,mortality, pruning needs assessments
Sidewalk Damage	numeric code describing extent of damage	costs, size and species associated with damage
Wire Conflict	numeric code describing utility line conflicts	costs, size and species associated with conflicts
Condition Wood	numeric code describing wood (structural) health of tree	asset value, structure
Condition Leaves	numeric code describing foliar (functional) health of tree	asset value, structure
OtherOne, Two, Three	numeric data field with up to 10 variables to be described by user	3 fields in STRATUM to be defined by user
Setback	distance between tree and nearest air-conditioned/heated space	energy analysis use/energy conservation projects
Tree Orient	numeric data listing 1 of 8 azimuth orientations of tree in reference to building	energy analysis use/energy conservation projects

Source: i-Tree program.

Essentially, the data to be collected will depend upon the project needs. To estimate carbon stocks, information on tree species and 'diameter at breast height' (dbh) are the minimum requirements.

A.2.3 Measuring Method and Allowable Error for Primary Measurements

This section describes the minimum data collection fields and allowable measurement error necessary to report under this protocol.

Species

The most common method for identifying species in an inventory is the use of species code – usually a four-letter code taken from first two letters of genus and species names, or four letters plus one number when genus and species letters are duplicated in study. Use species coding lists in i-Tree Manual 2.2 as guide. (Example: *Acer saccharum* = ACSA and *Acer saccharinum* (in same study) would be ACSA1).

Diameter at Breast Height (dbh in cm)

Measure the diameter at breast height (1.37m) to nearest 0.1 cm using a dbh tape (available from most forestry suppliers). Where possible for multi-stemmed trees forking below 1.37 m measure above the butt flare and below the point where the stem begins forking. When this is

not possible, measure diameter at root collar (DRC) as described below. Saplings (dbh/DRC 2.54 - 12.5 cm) will be measured at 1.37 m unless falling under multi-stemmed/unusual stem categories requiring DRC measurements (per FHM Field Methods Guide [see reference in CAR 2010]).

Diameter at Root Collar (DRC in cm)

The method for measuring diameter at the root collar is adapted from the FHM Field Methods Guide. For species requiring diameter at the root collar, measure the diameter at the ground line or at the stem root collar, whichever is higher. For these trees, treat clumps of stems having a unified crown and common root stock as a single tree; examples include mesquite, juniper, and mountain mahogany. For multi-stemmed trees, compute and record a cumulative DRC (see below); record individual stem diameters and a stem status (live or dead) on a separate form or menu as required.

Measuring DRC: Before measuring DRC, remove the loose material on the ground (e.g. litter) but not mineral soil. Measure just above any swells present, and in a location so that the diameter measurements are reflective of the volume above the stems (especially when trees are extremely deformed at the base).

Stems must be at least 1.0 ft in length and 1.0 inch in diameter to qualify for measurement; stems that are missing due to cutting or damage must have previously been at least 1.0 ft in length (estimate by checking diameter of wound and compare with diameter and length of other stems – checking taper).

Whenever DRC is impossible or extremely difficult to measure with a diameter tape (e.g. due to thorns, extreme number of limbs), stems may be estimated and recorded to the nearest 1.0 inch class.

Additional instructions for DRC measurements are illustrated in Figure A.1. Do not measure cut stems as shown in Diagram 5 of Figure A.1; measure only complete stems.

Computing and Recording DRC: For all trees requiring DRC, with at least one stem 1.0 inch in diameter or larger at the root collar, DRC is computed as the square root of the sum of the squared stem diameters. For a single-stemmed DRC tree, the computed DRC is equal to the single diameter measured and rounded to the nearest 0.1 inch.

Use the following formula to compute DRC:

$$DRC = SQRT\,[SUM\ (stem\ diameter^2)]$$

For example, a multi-stemmed woodland tree with stems of 12.2, 13.2, 3.8, and 22.1 would be calculated as:

$$DRC = SQRT\,[12.2^2 + 13.2^2 + 3.8^2 + 22.1^2]$$
$$= SQRT\,[825.93]$$
$$= 28.74$$
$$= 28.7$$

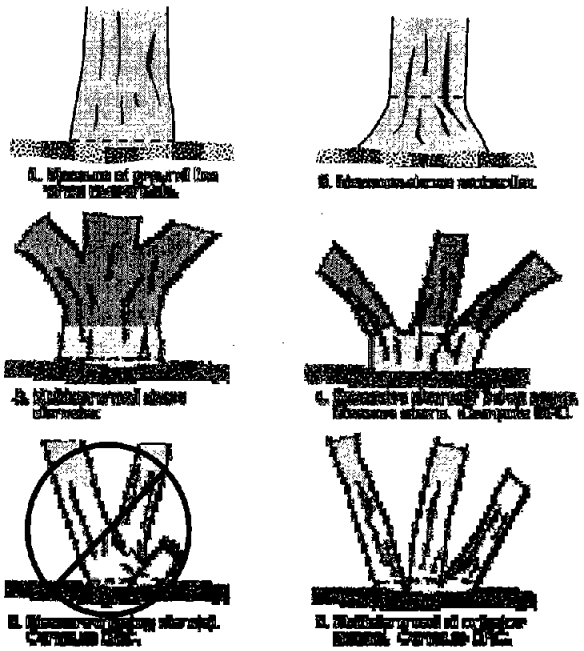
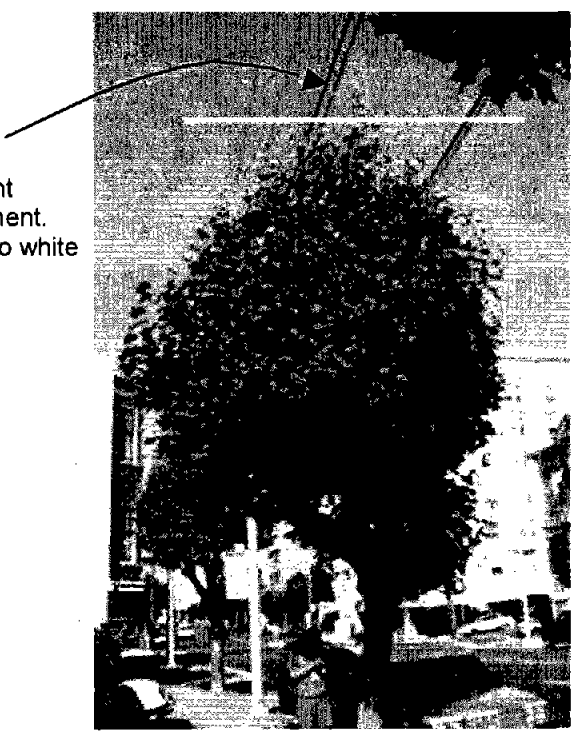


Figure A.1. Measuring DRC in Various Situations

Tree Height

From ground level to tree top to nearest 0.5 m (omit erratic leader as shown in Figure A.2) with range pole, altimeter or clinometer.



Tree height measurement. Measure to white line.

Figure A.2. Example of Tree with Erratic Leader

A.3 Sampling from Populations

As previously mentioned, sampling involves measuring only a portion of the trees on the offset project and using the data to estimate parameters of interest for the overall population.

A.3.1 Statistical Bias

The reason for using statistically sound sampling methods is to avoid bias in the estimates of the parameter(s) measured. Although the value of any single estimate (biased or not) is unlikely to equal the true population value, the mean of a large number of unbiased estimates will approximate the true value. In contrast, the mean of a large number of biased estimates will either be higher or lower than the true population value, depending on the direction of the bias. If the project developer is interested in knowing the actual value of a parameter from the population (e.g. actual tree dbh), they generally want to use an unbiased estimator of that parameter. In some situations, a small bias (e.g. a tendency to slightly over- or underestimate cover) can be tolerated if the bias is small relative to the standard deviation of the estimation errors (perhaps 10% to 15% or less).

Bias in estimates can come from various sources. For instance, if tree shadows are counted as canopy in aerial photo interpretation (misclassification bias), the canopy cover estimate will be biased upward. Many types of bias can be avoided through good sampling design and the careful implementation of appropriate evaluation techniques.

A.3.2 Random Sampling and Random Numbers

Most statistical methods used in environmental areas are based on the assumption of random sampling. This means that every unit in the population has an equal chance (or known probability) of being chosen for the sample. Furthermore, the selection of random units should be independent of other units that have been sampled. If a sample unit is rejected because it is too close to one already chosen, the sample will not be random and independent. A relatively simple and reliable method for randomization is to use random numbers. Most spreadsheet, database, and statistical programs have functions that generate random numbers, or random numbers can be found on-line or chosen from printed tables.

Several techniques can be used to draw a random sample from a population that consists of individual objects or records (e.g. street addresses or tree numbers). Many spreadsheet programs include tools that can produce a random sample of a specified size from a range of cells. Alternatively, a unique random number can be assigned to each unit or record, sorting the list based on the random number, and picking the required number of units from the top of the sorted database.

In some cases, it is necessary to take random samples across a geographic area, such as part or all of a city or forested area. In such a situation, random sample points can be assigned by randomly sampling from a coordinate grid that has been established for the area in question. This may either be an existing set of map-based coordinates, such as UTM or State Plane grids, or an arbitrary grid based on units measured on a map or aerial photograph (e.g. distances measured from the bottom and left edge of the map or photo). After the range of X and Y coordinates have been determined within the area to be sampled, X and Y coordinates can be selected randomly to generate random sample points. This is simple random sampling, one of

five common random sampling techniques. The other four include systematic sampling, stratified sampling, cluster sampling, and multi-stage sampling.

A.3.3 Systematic Sampling

Systematic sampling means that the sample units are selected at equally spaced intervals over a population. Examples include selecting every tenth tree from a list of trees or selecting sample plots at equally spaced distances over a project area. In carefully planned forest surveys, systematic sampling can yield more precise results than simple random sampling. Systematic sampling is unbiased if the first unit is randomly selected. One advantage to systematic sampling is that it is simpler to select one random number and then collect data on every 5th, 10th or 15th (project developer chooses the interval) tree on the list, than to select as many random numbers as the sample size (although these numbers can be generated by any spreadsheet program). It also provides a good spread across a tree population. A disadvantage is that a list is needed to start with to be able to know total sample size and to calculate a sampling interval. The only advantage of systematic sampling over simple random sampling is the simplicity of needing to choose only one random number.

A.3.4 Stratified Sampling

In many urban forest applications, it is desirable to have samples distributed throughout the population. For instance, the project developer may want to ensure that trees from each of several different land use zones are included in the sample because it has been determined that trees are growing differently in different land use areas due to differences in care and maintenance. In such situations, stratified random sampling will be the most efficient and meaningful method for selecting samples. In this method, the population to be sampled is first divided into meaningful subunits or strata. These may be large subdivisions, planning sectors, maintenance districts, or any other convenient management or planning unit.

If strata are assigned so that each is more or less homogeneous with respect to the characters being measured, fewer samples will be needed to adequately characterize each stratum. For instance, if tree cover is to be assessed in different portions of a city, visual estimates of the tree canopy cover could be used to help demarcate zones where canopy cover is relatively uniform. A sample of street trees might be stratified by tree species, size, and/or age, depending on the purpose of the evaluation. If these trees were classified in a municipal street tree database, stratification might be accomplished relatively simply from existing tree data. However, if such data are lacking, it may be necessary to conduct a preliminary sample to delineate the population before sampling occurs.

Once strata are assigned and delineated, samples are drawn at random from within each stratum. If the number of samples selected from each stratum is not proportional to the size of the stratum, the averages from each will have to be weighted to obtain an overall population average. Given prior knowledge about the population, stratified sampling is a commonly used probability method that is superior to random sampling because it reduces error.

A.3.5 Sampling Size

Optimal sample size will vary somewhat with the characteristics being rated or tallied.

In general:

- Up to a point, the reliability of estimates will increase as sample size increases

- The more variable the population is with respect to the characteristic(s) being rated, the larger the sample should be
- A large sample is required to accurately estimate the frequencies of relatively rare events or characteristics
- Larger sample sizes are needed to detect relatively small differences between means or proportions; smaller sample sizes may suffice if the differences are relatively large

The optimum sample size represents a compromise between cost and accuracy, since both generally increase with increasing sample size. An optimum sample size can be determined by identifying the point of diminishing returns beyond which further increases in accuracy are not worth the additional costs of data collection. Optimum sample size will vary with the type of data being collected, so it is not possible to set a single number for all applications.

However, certain statistical formulas can be used to estimate the minimum sample size needed for a specific purpose. A number of statistics web sites include on-line interactive calculators that allow required sample sizes to be estimated. Before these sample size calculators can be used, several things must be known about the data that will be collected and how it will be analyzed.

Type of Data

Main types include:

1. Continuous – variables can take any value, e.g. tree diameters
2. Discrete – variables can only have certain discrete values
    a. Types of discrete data include:
        i. Ranks – ordered ratings, e.g. low, moderate, high
        ii. Counts – e.g. number of trees by species or dbh class
        iii. Binary – variable has only two outcomes, e.g. present/absent. Binary data is typically expressed as proportions or percents, such as the percent canopy cover determined from dot grid counts (canopy is rated as present or absent for each dot)

Type of Analysis

Continuous data are typically analyzed using linear models, including linear regression and analysis of variance techniques. Discrete data may be analyzed in various ways, including contingency table analysis, logistic regression, and survival analysis. Different formulas are used to estimate sample sizes for various analysis methods.

Expected Values

To estimate sample sizes for analyses of continuous data, estimates of expected population means (the Greek letter mu may be used for this term) and standard deviations or variances (the Greek letter sigma symbolizes the population standard deviation; variance is the square of the standard deviation) will have to be specified. For proportions, estimates of the expected proportions are needed; margins of error (as percents) may also be needed.

Data Structure

If data are paired or arranged in blocks or other more complex designs, the structure of the statistical model should be specified.

Confidence Level

Also abbreviated as the Greek letter alpha, this is the probability of Type I error, the chance that a difference is significant when it really is not (i.e. the probability of rejecting the null hypothesis when it is true). This is typically set at a low level, often 5% (alpha=0.05), meaning that there would only be a 5% (1 in 20) chance of deciding that a spurious difference is real (i.e. a 95% chance of avoiding Type I error).

Power

This parameter is expressed as (1-beta) where beta is the probability of Type II error. Power is the probability of detecting a real difference (i.e. the probability of rejecting the null hypothesis when it is false). When detecting real differences, the power of a test should be high, generally at least 80% (0.8) or greater.

A.3.6 Sampling Design and Monitoring Frequency

The frequency of monitoring is related to the rate and magnitude of change in tree growth, removal rates, planting rates and so forth – the smaller the expected change, the greater the potential that frequent monitoring will not detect a significant change. Frequency of monitoring should be determined by the magnitude of expected change – less frequent monitoring is applicable if only small changes are expected (see reference in CAR 2010).

All sampling designs should incorporate some form of random sampling to quantify the carbon stocks within established project boundaries using statistically accepted methods for inferring the urban forest biomass based on sample plots. There are multiple ways one can design a sampling plan. Although a few examples are provided here, it is important to remember that the specific sampling method used should be determined after evaluating project size, monitoring frequency and acceptable level of sampling error. Four basic designs are addressed here.

1. ***Rolling Sample***
   A percentage of the complete inventory is sampled annually, with results used to infer biomass or volume for the complete inventory.

   > Example: during year 1 a non-profit tree group plants 3,000 new tree sites along a greenway, with a variety of species mixed throughout the area. Each year, 10% of the tree sites are sampled, until, at the end of 10 years, 100% of the inventory has been sampled. The annual 10% samples are fixed samples proportional to representation. Thus, the complete inventory is divided into 10 samples at the outset of the project. These 10% samples may be based on stratified random sampling with species type and frequency (number of trees planted per species) as the strata, or to reduce data collection costs, trees could be clustered into 10 cohorts based on geographic proximity. Other forms of random sampling, including cluster sampling for obtaining the 10% sample may also be suitable.

2. ***Periodic Sampling***
   All trees are re-inventoried but not annually. A sampling period is determined at the outset. For example, all trees are re-inventoried every 6 years.

3. ***Fixed Plot Sampling***
   All trees in a geographical area are never completely inventoried. A set of plots of fixed size and number are established and used to extrapolate volume or biomass on an area basis. Example: the city of San Francisco establishes a new 30-mile long multi-use

greenway along a former railroad corridor. They employ the UFORE plot sampling method (see references in CAR 2010) and establish thirty 10-m radius permanent plots based on land use stratification. The plots are sampled annually. Biomass or volume for the greenway is extrapolated based on sample plots to area relationship.

4. ***Variable Plot***
   Variable plot is similar to fixed plot sampling except the area sampled varies to coincide w/ logistical requirements, such as property boundaries where permission to access private property is required. Area of the plot is measured and used to infer to the total area based on plot area to total area ratio.

Note that items 1 and 2 can be applied to items 3 and 4; they are potentially at different levels or scales within a sampling design.

A.3.7 Minimum Required Sampling Criteria

All sampling methodologies and measurement standards must be statistically sound and reviewed by verification bodies. All sample plots should be permanently benchmarked for auditing and monitoring purposes. Plot centers, street segments, or individual trees (in the case of some forms of rolling samples) should be referenced on maps, preferably using GPS coordinates or using GIS. The methods utilized shall be documented and made available for verification and public review. The design of the sampling methodology and measurement standards must include the requirements stated in Table A.2.

Table A.2. Minimum Required Sampling Criteria

GHG Reservoir	Required?	Name of Requirement	Description of Requirement
Tree Biomass	Yes	Diameter (breast height) Measurements	Stated minimum diameter in methodology not to be greater than 7.6 cm (3 in.)
		Measurement Tools	Description of tools used for height, diameter, and plot measurement.
		Measurement Standards	The methodology shall include a set of standards for height and diameter measurements and describe compliance with allowable measurement error.
		Stratification Design	A description of the rules used to stratify the trees.
		Plot Layout	A description of the plot layout.
		Allometric Equations used for Estimating Biomass	The methodology shall include a description of the allometric equations used to estimate the whole tree biomass (bole, branches, and roots) from bole diameter measurements. This includes a description of how equations were assigned and implemented. Use only the equations provided in this protocol.

A.3.8 Sampling Error

All estimates of reported GHG reservoirs must have a high level of statistical confidence. Measurement standards are established by ARB for the estimate of metric tons of carbon in the required pools derived from sampling. Confidence in the estimate of metric tons of carbon from

sampling can be measured statistically in terms of the size of the standard error relative to the estimate of the mean. This establishes confidence limits and can be expressed as a percentage of the mean. Larger confidence intervals indicate that there is less confidence in the mean estimate than smaller confidence intervals. For all GHG reservoirs reported, the standard error must be within 20% of the estimate of the mean for the estimate to be accepted. However, estimates are adjusted based on the statistical level of confidence, such that only estimates with a standard error within 5% or less receive no deduction. Most spreadsheet software packages provide users the ability to run descriptive statistics on a set of data, and results include the mean, standard error, standard deviation and confidence level. Table A.3 provides an example of summary results for each plot in a measured stratum. Note that standard deviation quantifies the scatter, how much the measured values differ from one another, whereas, standard error quantifies how accurately the true mean of the population is known. Standard error gets smaller as the sample gets larger, but standard deviation does not change predictably since it only quantifies scatter.

Table A.3. Summary Results for Each Plot in a Stratum

Plot #	Carbon Tons per Hectare	Plot #	Carbon Tons per Hectare	Plot #	Carbon Tons per Hectare
1	337	8	367	15	342
2	296	9	260	16	366
3	308	10	260	17	355
4	271	11	322	18	423
5	289	12	323	19	437
6	228	13	439	20	156
7	144	14	309		
Average Carbon Tons per Hectare					312
Standard error (must be <20% of mean)					17.85

Note: Confidence level is less than 10% of the mean as required by ARB.

Appendix B Calculating Biomass and Carbon – Quantification Methodology[12]

This appendix describes how measured tree size data are used with biomass equations to calculate tree volume and carbon content. Equations are presented for 26 open-grown urban tree species. To be consistent with biomass equations used in the Compliance Offset Protocol U.S. Forest Projects, foliar biomass is not included in the formulations. Additional biomass equations have been adapted from the literature on natural and native forest biomass for use in urban settings. The urban species equations have also been used to develop two general equations for broadleaf trees and conifers. Complete listings of equations are available in Table B.1 and Table B.2 at the end of this appendix. Table B.1 lists equations based on measurements of dbh and height or dbh only, derived from data collected on open-grown trees. Additional information can be found in CAR 2010 section B.5 pg 67-68.

B.1 Estimating Biomass and Carbon Using Volumetric Equations

Estimating biomass and carbon using volumetric equations is a two-step process that entails 1) calculating green volume, and 2) converting green volume to dry weight biomass and then carbon content (C). Table B.1 and Table B.2 provide examples of volumetric equations and biomass conversion factors for common urban species. Table B.1 equations estimate volume (m^3/tree) from diameter at breast height (dbh in centimeters) and height (in meters) measurements.

1. Use equations for dbh and height (or equations for dbh only if necessary) to calculate volume.

   Example:
   Volume in cubic meters (V) for a 15.6 m tall hackberry (*Celtis occidentalis*) with a 40.4 cm dbh is calculated as:

$$V = 0.002245 \times (40.4)^{2.118} \times (15.6)^{-0447} \quad \text{[Eq. 1]}$$
$$= 1.66\ m^3$$

2. Determine freshweight (FW) biomass, dry weight (DW) biomass and carbon content by applying biomass conversion factors in Table B.1, incorporating belowground biomass, and calculating carbon.

   a. Convert from volume to FW biomass by multiplying V by the species-specific density factor.

      For hackberry, FW would be calculated as:

$$FW = 1.66 \times 801 \quad \text{[Eq. 2]}$$
$$= 1329.66\ kg$$

[12]The entirety of Appendix B is considered a quantification method.

b. The equations given here only calculate volume (and hence biomass) for the *aboveground* portion of the tree. Add the biomass stored belowground by multiplying the FW biomass by 1.28. For total FW biomass, including belowground roots calculate:

$$\text{Total FW} = 1329.66 \times 1.28 = 1704.62 \text{ kg} \quad \text{[Eq. 3]}$$

c. Convert FW biomass into DW biomass by multiplying by the constant 0.56 for hardwoods and 0.48 for conifers (see reference in CAR 2010). For our hackberry example:

$$\text{DW} = 1704.62 \times 0.56 = 954.59 \text{ kg} \quad \text{[Eq. 4]}$$

d. Convert DW biomass into kilograms of carbon (C) by multiplying by the constant 0.50:

$$\text{C} = 954.59 \times 0.5 = 477.30 \text{ kg} \quad \text{[Eq. 5]}$$

e. Tree carbon stock is to be reported in metric tons. Therefore, results calculated in kilograms must be multiplied by 0.001 to convert to metric tons.

B.1.1 Estimating Biomass and Carbon Using Forest-Derived Equations

Biomass calculated using equations derived from native or natural forest trees (Table B.2) must be adjusted by a factor of 0.80 when applied to open-grown, urban trees because of differences in biomass allocation between the tree populations.

Unlike the equations used above, the forest equations listed produce DW biomass rather than FW biomass. Therefore the step involving the species-specific density factor (step 2a above) does not need to be incorporated. The calculation for carbon content (kg) is:

$$\text{C} = \text{DW} \times 1.28 \times 0.5 \quad \text{[Eq. 7]}$$

B.1.2 Estimating Tree Biomass for Standing Dead or Dying Trees

Unlike trees in forest settings, dead or dying trees in urban areas are usually removed immediately due to safety concerns in public and private areas. Typically, the only difference between biomass in a live tree and that in a dead tree is the absence of foliage for the latter.

Because foliar biomass is not included in these formulations, dead and dying tree biomass should be calculated just as for live tree biomass.

B.1.3 Estimating Carbon in Lying (Dead/Downed) Tree Biomass

As discussed in Section B.1.2 above, it is assumed in nearly all urban applications that dead/dying trees are removed almost immediately and that lying tree biomass will rarely, if ever exist. It is most likely to exist in natural settings within cities like riparian or nature areas. In that case, sampling, measurement and carbon estimation procedures should follow the Compliance Offset Protocol U.S. Forest Projects rather than this protocol.

B.2 Error in Estimating Carbon and Biomass

The volume equations used in this protocol were developed from trees that may differ in size from the trees in a specific sample or inventory. The dbh ranges for trees sampled to develop the volume and biomass equations are listed where known at the end of the appendix (Table B.1 and Table B.2). Applying the equations to trees with dbh outside of this range may increase the error in estimates.

B.3 Reporting Uncertainty versus Inherent Uncertainty

Reporting uncertainty is the level of uncertainty associated with an entity's chosen carbon stock sampling and calculation methodologies. Inherent uncertainty refers to the scientific uncertainty associated with calculating carbon stocks and GHG emissions.

There is an inherent scientific uncertainty in quantifying carbon stocks of entities. However, determining scientific accuracy is not the focus of this protocol. Instead, the verification process is designed to identify and assess reporting uncertainty. Therefore, when assessing if the estimate of the carbon content in project trees meets ARB's minimum quality standard, only quantification differences that result from reporting uncertainty should be considered, not inherent uncertainty. Therefore, it is not necessary to attempt to quantify error for biomass equations accepted by ARB. Any statistical error associated with these equations falls under the category of inherent uncertainty.

Table B.1. Volume Equations for 26 Urban Tree Species

	Species	DBH Range (cm)	Volume (m^3)	Vol to FW Conversion kg/m3
	Acacia longifolia	15.0 - 57.2	=0.0283168466 (0.048490 * (dbh/2.54)$^{2.347250}$)	1121
	Acer platanoides	9.7 - 102.1	=0.0019421 * dbh$^{1.748}$	737
	Acer saccharinum	13.2 - 134.9	=0.000383 * dbh$^{2.388}$	721
	Celtis occidentalis	10.9 - 119.4	=0.0014159 * dbh$^{1.928}$	801
	Ceratonia siliqua	15.5 - 71.4	=0.0283168466(0.066258 * (dbh/2.54)$^{2.128861}$)	961
D	Cinnamomum camphora	12.7 - 66.8	=0.0283168466(0.031442 * (dbh/2.54)$^{2.[illegible]}$)	817
B	Cupressus macrocarpa	15.7 - 146.8	=0.0283168466(0.035598 * (dbh/2.54)$^{2.[illegible]}$)	577
N	Eucalyptus globulus	15.5 - 130.0	=0.0283168466(0.055113 * (dbh/2.54)$^{2.[illegible]}$)	1121
	Fraxinus pennsylvanica	14.7 - 122.7	=0.0005985 * dbh$^{2.[illegible]}$	785
O	Fraxinus velutina 'Modesto'	14.5 - 84.8	=0.0283168466(0.022227 * (dbh/2.54)$^{2.[illegible]}$)	769
N	Gleditsia triacanthos	9.1 - 98.3	=0.0005055 * dbh$^{2.[illegible]}$	977
L	Gymnocladus dioicus	10.2 - 36.6	=0.0004159 * dbh$^{2.[illegible]}$	929
Y	Jacaranda mimosifolia	17.3 - 59.7	=0.0283168466(0.036147 * (dbh/2.54)$^{2.[illegible]}$)	609
	Liquidambar styraciflua	14.0 - 54.4	=0.0283168466(0.030684 * (dbh/2.54)$^{2.[illegible]}$)	801
	Magnolia grandiflora	14.5 - 74.2	=0.0283168466(0.022744 * (dbh/2.54)$^{2.[illegible]}$)	945
	Pinus radiata	16.8 - 105.4	=0.0283168466(0.019874 * (dbh/2.54)$^{2.[illegible]}$)	705
	Pistacia chinensis	12.7 - 51.3	=0.0283168466(0.019003 * (dbh/2.54)$^{2.[illegible]}$)	657
	Platanus acerifolia	15.5 - 73.9	=0.0283168466(0.025170 * (dbh/2.54)$^{2.[illegible]}$)	833
	Populus sargentii	6.4 - 136.7	=0.0020891 * dbh$^{1.873}$	753
	Quercus ilex	12.7 - 52.1	=0.0283168466(0.025169 * (dbh/2.54)$^{2.[illegible]}$)	1166
	Quercus macrocarpa	10.9 - 100.1	=0.0002431 * dbh$^{2.[illegible]}$	993
	Tilia cordata	11.2 - 84.5	=0.0008359 * dbh$^{2.[illegible]}$	873
	Ulmus americana	17.5 - 114.3	=0.0018 * dbh$^{1.[illegible]}$	865
	Ulmus parvifolia chinensis	17.3 - 55.9	=0.0283168466(0.026530 * (dbh/2.54)$^{2.[illegible]}$)	865
	Ulmus pumila	15.5 - 131.8	=0.0048679 * dbh$^{1.[illegible]}$	865
	Zelkova serrata	14.5 - 86.4	=0.0283168466(0.021472 * (dbh/2.54)$^{2.[illegible]}$)	865
	General Broadleaf	6.4 - 136.7	=0.280285*(dbhcm)^2.310847	Eqtn produces FW
	General Conifer	6.4 - 136.7	=0.09954*(dbhcm)^2.590971	Eqtn produces FW
	Acacia longifolia	15.0 - 57.2	=0.0283168466(0.01406 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	1121
	Acer platanoides	9.7 - 102.1	=0.001011 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	737
	Acer saccharinum	13.2 - 134.9	=0.000298 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	721
D	Celtis occidentalis	10.9 - 119.4	=0.002245 * dbh$^{2.[illegible]}$ * ht$^{-0.[illegible]}$	801
B	Ceratonia siliqua	15.5 - 71.4	=0.0283168466(0.00857 * (dbh/2.54)$^{1.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	961
N	Cinnamomum camphora	12.7 - 66.8	=0.0283168466(0.00982 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	817
	Cupressus macrocarpa	15.7 - 146.8	=0.0283168466(0.00576 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	577
a	Eucalyptus globulus	15.5 - 130.0	=0.0283168466(0.00309 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	1121
n	Fraxinus pennsylvanica	14.7 - 122.7	=0.000414 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	785
d	Fraxinus velutina 'Modesto'	14.5 - 84.8	=0.0283168466(0.00129 * (dbh/2.54)$^{1.[illegible]}$ * (3.28*ht)$^{1.[illegible]}$)	769
	Gleditsia triacanthos	9.1 - 98.3	=0.000469 * dbh$^{2.[illegible]}$ * ht$^{0.[illegible]}$	977
H	Gymnocladus dioicus	10.2 - 36.6	=0.000463 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	929
E	Jacaranda mimosifolia	17.3 - 59.7	=0.0283168466(0.01131 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	609
I	Liquidambar styraciflua	14.0 - 54.4	=0.0283168466(0.01177 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	801
G	Magnolia grandiflora	14.5 - 74.2	=0.0283168466(0.00449 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	945
H	Pinus radiata	16.8 - 105.4	=0.0283168466(0.00533 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	705
T	Pistacia chinensis	12.7 - 51.3	=0.0283168466(0.00282 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	657
	Platanus acerifolia	15.5 - 73.9	=0.0283168466(0.01043 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	833
	Populus sargentii	6.4 - 136.7	=0.001908 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	753
	Quercus ilex	12.7 - 52.1	=0.0283168466(0.00431 * (dbh/2.54)$^{1.[illegible]}$ * (3.28*ht)$^{1.[illegible]}$)	1166
	Quercus macrocarpa	10.9 - 100.1	=0.000189 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	993
	Tilia cordata	11.2 - 84.5	=0.000945 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	873
	Ulmus americana	17.5 - 114.3	=0.0012 * dbh$^{1.[illegible]}$ * ht$^{0.[illegible]}$	865
	Ulmus parvifolia chinensis	17.3 - 55.9	=0.0283168466(0.01048 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	865
	Ulmus pumila	15.5 - 131.8	=0.0003336 * dbh$^{0.[illegible]}$ * ht$^{2.[illegible]}$	865
	Zelkova serrata	14.5 - 86.4	=0.0283168466(0.00686 * (dbh/2.54)$^{2.[illegible]}$ * (3.28*ht)$^{0.[illegible]}$)	865

Note: Equations require dbh (cm) only or dbh (cm) and height (m) measurements to calculate volume. Factors are listed for converting volume to freshweight (FW), and two FW general biomass equations derived from these species are also listed.

Source: Climate Action Reserve (2010) Urban Forest Project Protocol Version 1.1 March 10, 2010.

Table B.2. Dry Weight Biomass Equations

Spcode	Botanic	Common	Model	Source and DBH Range
ACRU	Acer rubrum	Red maple	$=(0.1970*(dbh^{2.1973}))*0.80$	Ter-Mikaelian, Nova Scotia 0-35 cm red maple
ACSA2	Acer saccharum	Sugar maple	$=(0.1791*(dbh^{2.3329}))*0.80$	Ter-Mikaelian, Maine 3-66 cm sugar maple
PRSE2	Prunus serotina	Black cherry	$=((0.0716*dbh^{2.6174}))*0.80$	Ter-Mikaelian, West VA 5-50 cm black cherry
QURU	Quercus rubra	Northern red oak	$=(0.1130*(dbh^{2.4572}))*0.80$	TerMikaelian, West VA 5-50 cm red oak
FRAM	Fraxinus americana	White ash	$=(0.1063*(dbh^{2.4708}))*0.80$	Ter-Mikaelian, West VA 5-50 cm white ash
TIAM	Tilia americana	American basswood	$=((0.0617*dbh^{2.6729}))*0.80$	Ter-Mikaelian, West VA 5-50 cm basswood
BENI	Betula nigra	River birch	$=(0.0692*(dbh^{2.6696}))*0.80$	Ter-Mikaelian, West VA 5-50 cm black birch
Palms	General palms	General palms	$=(6.0*ht(m)+0.6)+(2.5*ht(m)+0.9)$	Frangi and Lugo, 1985
Hardwoods	General hardwoods	General hardwoods	$=((EXP(-2.437+2.418*(LN(dbh)))+EXP(-3.188+2.226*(LN(dbh)))))*0.8$	Tritton and Hornbeck, Northeast, 10-50 cm

Note: Use constants to add roots, convert to carbon. Biomass is reduced to 80% of original predicted value to account for less biomass in urban trees.

Appendix C Offset Project Listing Information

Section 1: General Information

1. Date of form completion:
2. Form completed by (name):
3. Project listing as a:
   - Municipal Project
   - Educational Campus Project
   - Utility Project
4. Name and contact information of the Offset Project Operator:
5. Name and contact information of Authorized Project Designee (if applicable):
6. Offset project commencement date:
7. Date of initial reporting period:
8. Location of offset project (including approximate latitude/longitude):

Section 2: Offset Project Summary

1. Describe the goals of the offset project.
2. Name of the person or entity that is responsible for planning, implementation, and reporting of project activity. List and explain the involvement of Authorized Project Designees, if applicable.
3. Briefly describe implementation of the offset project. Include general information on the number of project tree sites and trees that will be planted (including replacements), types of species, where they will be planted, tree maintenance and monitoring plans (Note: Some of this information is also required in the Tree Maintenance Plan [separate document]):
4. Confirm that the trees will be planted in maintained landscapes and spaced at least 5 m (16 ft) apart so as to be open-growing (Y/N):

Section 3: Offset Project Boundaries

1. Physical Boundary: Describe and include a map of the physical boundary of the offset project, including planned tree sites, an outline of the geographical boundary of the municipality, educational campus, or utility service area, and tree care facilities (location where vehicles and equipment are housed):
2. GHG Offset Project Boundary: List the GHG sources and GHG sinks that will be included in the Offset Project Boundary.

Section 4: Offset Project Eligibility

1. State the expected average annual net number of project tree sites created over the Project Life (this is the project NTG):
2. State the average annual NTG prior to offset project commencement (for municipalities and educational campuses only):

3. State the total number of trees prior to the start of the offset project (for municipalities and educational campuses only):
4. Is any portion of the project activity required by any local, state, regional, or federal regulation? (Y/N)
5. Describe tree planting requirements outside of the project activity that are mandated by law and are planned to be undertaken by the entity:

Section 5: Tree Maintenance Plan

This initial Tree Maintenance Plan constitutes a description of planned maintenance activities. Per Section 8 of the protocol, approved offset projects must annually submit a Tree Maintenance Plan for each year of project duration, reporting activities ex post. This initial Tree Maintenance Plan must address the following requirements:

1. Document the most recent and anticipated future levels of service and expenditures for all criteria in the Tree Maintenance Plan (for details, see protocol Section 9: Project Monitoring).
2. Describe how project tree planting sites will be identified and prioritized.
3. Provide estimates for tree mortality rates for newly planted and established project trees, and explain how these estimates were derived.
4. Describe how project trees that need replacing will be identified, the timing of replacement, and the species and size of replacement trees.
5. Identify the personnel who will implement and manage the project, their roles and responsibilities, and funds required for salary, operations, training, and overhead over the duration of the project. Other activities that may be included here are public relations, accounting, fund raising, and outreach.

Section 6: Project Tree Monitoring Plan

Per Section 8.2 of the protocol, the Project Tree Monitoring Plan must address the following requirements:

Provide a detailed description of:

1. Method chosen from the options in Section 5.1.
2. Procedures that will be used to census, measure, and report information on the project trees, including survey method, sample sizes, and method for choosing samples.
3. Methods that will be used to measure and record tree dimensions.
4. Methods that will be used and information collected on tree survival and health.
5. Statistical methods that will be used to extrapolate sample data to the total project tree population, if applicable.
6. Estimating sampling error, if applicable.

Appendix D Offset Project Data Report

Each Offset Project Data Report must contain the following:

1. Offset Project Operator or Authorized Project Designee
2. Offset Project Name
3. Name of Individual Completing the Report
4. Date
5. Verification Period
6. Project personnel
7. Personnel names(s)
8. Organization and title(s)
9. Responsibilities

10. Equations and calculations

    a. Project tree volume, biomass, and carbon stocks (for measured trees and for the project tree population, if sampling and extrapolation are used) at project commencement (or renewal) and annually thereafter.

    b. For (a) above, standard error and sampling error at the 90% confidence interval must be met, if applicable.

    c. Amount and type of fuel consumed by project vehicles and equipment.

    d. Project tree carbon stock change and adjusted carbon stock change, if applicable.

    e. Tree planting
        i. Number of trees planted in new tree sites each year, not including replacement trees (total for the municipality, educational campus, or utility service area, including project and non-project trees).
        ii. Number of trees planted to replace removed trees each year ("replacement trees"), including replacement trees planted in relocated tree sites (separately for non-project and project trees).
        iii. Species, size, and location of project trees planted in new tree sites each year.
        iv. Species, size, and location of project replacement trees planted in existing or relocated tree sites each year.
        v. Number and location of relocated project tree sites each year.
        vi. Reasons for relocations and, if applicable, modifications made to the project to reduce the chance of future relocations.
        vii. Project tree resource: Percentage of total project trees planted.

viii. Annual tree planting expenditure (separately for the project and the municipality, educational campus, or utility).

f. Young tree care
   i. Number of young project trees inspected/pruned each year.
   ii. Inspection/pruning cycle (total number of project trees / number treated per year).
   iii. Annual expenditure (separately for the project and the municipality, educational campus, or utility).

g. Mature tree care
   i. Number of mature project trees inspected/pruned each year.
   ii. Inspection/pruning cycle (total number of project trees / number treated per year).
   iii. Annual expenditure (Reported annually, separately for the project and for the municipality, educational campus, or utility).

g. Tree removal
   i. Number of trees removed from existing tree sites each year (separately for non-project and project trees).
      xiii. Species, size, and location[13] of project trees removed each year.
   ii. Reasons for removals and, if applicable, modifications made to the project to reduce the chance of future removals.
   iii. Removal cycle (total number of project trees to remove / number removed per year).
   iv. Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

h. Administration/other
   i. Average $/tree site expenditure (total $ on administration and other / total tree numbers) (separately for the project and municipality, educational campus, or utility).
   ii. Annual expenditure (separately for the project and for the municipality, educational campus, or utility).

j. Net Tree Gain for each year and annual averages (Section 3.4.2) at the level of the municipality or educational campus.

k. Net Tree Gain for each year at the project level.

11. Project Tree Monitoring Plan
   a. Choice of method from the options in Section 5.1.

[13] Tree site location must be designated on a map of the project physical boundaries.

b. Detailed description of procedures to census (or sample, if applicable), measure, and report information on the project trees, including the survey method, sample sizes, and method for choosing samples.
c. Methods used to measure and record tree size.
d. Methods used and information collected on tree survival and health.
e. Statistical methods used to extrapolate sample data to the total project tree population, if applicable.
f. Estimated sampling error, if applicable.

12. Calculated project GHG reductions (removal enhancements, by year):
    a. Project tree CO_2 sequestration (adjusted for sampling error, if applicable)
    b. Project vehicle CO_2 emissions
    c. Project equipment CO_2 emissions
    d. Project GHG reductions (removal enhancements)

October 2011



California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol Livestock Projects

Capturing and Destroying Methane from Manure Management Systems

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

ARB	California Air Resources Board
BCS	Biogas control system
BDE	Biogas destruction efficiency
CAR	Climate Action Reserve
CH_4	Methane
CNG	Condensed natural gas
CO_2	Carbon dioxide
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse gas
GWP	Global Warming Potential
IPCC	Intergovernmental Panel on Climate Change
lb	Pound
LNG	Liquefied natural gas
MS	Management system
MT or t	Metric ton
N_2O	Nitrous oxide
NG	Natural gas
QA/QC	Quality Assurance/Quality Control
Regulation	Regulation, title 17, California Code of Regulations, sections 95800 et seq.
scf	Standard cubic foot
SSR	Source, sink, and reservoirs
STP	Standard temperature and pressure

TAM	Typical average mass
VS	Volatile solids

1 Introduction

The Compliance Offset Protocol Livestock Projects provides methods to quantify and report greenhouse gas (GHG) emission reductions associated with the installation of a biogas control system (BCS) for manure management on dairy cattle and swine farms. The protocol focuses on quantifying the change in methane emissions, but also accounts for effects on carbon dioxide emissions. The protocol is based on the Climate Action Reserve's Livestock Project Protocol Version 2.2[1] and includes some clarifications and updates from Version 3.0.[2].

Offset Project Operators or Authorized Project Designees that install manure biogas capture and destruction technologies use the methods contained in this protocol to quantify and report GHGs. The protocol provides eligibility rules, methods to quantify GHG reductions, offset project-monitoring instructions, and procedures for preparing Offset Project Data Reports. Additionally, all offset projects must submit to annual, independent verification by ARB-accredited verification bodies. Requirements for verification bodies to verify Offset Project Data Reports are provided in the Cap and Trade Regulation (Regulation).

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification of GHG emission reductions associated with a livestock digester project. The protocol is comprised of both quantification methodologies and regulatory program requirements to develop a livestock project and generate ARB or registry offset credits.

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[3], 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 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.

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[1] Climate Action Reserve (2009) Livestock Project Protocol Version 2.2. November 3, 2009. http://www.climateactionreserve.org/wp-content/uploads/2009/03/Livestock-Project-Protocol-Version2.2.pdf (accessed November 3, 2009)

[2] Climate Action Reserve (2010) Livestock Project Protocol Version 3.0. September 29, 2010.] http://www.climateactionreserve.org/wp-content/uploads/2009/03/U.S._Livestock_Project_Protocol_V3.02.pdf (accessed September 29, 2010)

[3] Health and Safety Code section 38571

2 The GHG Reduction Project

2.1 Background

Manure treated and stored under anaerobic conditions decomposes to produce methane, which, if uncontrolled, is emitted to the atmosphere. This predominantly occurs when livestock operations manage waste with anaerobic liquid-based systems (e.g. in lagoons, ponds, tanks, or pits). Within the livestock sector, the primary drivers of methane generation include the amount of manure produced and the fraction of volatile solids that decompose anaerobically. Temperature and the retention time of manure during treatment and storage also affect methane production.

2.2 Project Definition – Quantification Methodology

For purposes of this protocol, offset project is defined as the installation of a biogas control system that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations.[4] The biogas control system must destroy methane gas that would otherwise have been emitted to the atmosphere in the absence of the offset project from uncontrolled anaerobic treatment and/or storage of manure.[5]

Captured biogas can be destroyed on-site, or transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles. Regardless of how biogas is utilized, the ultimate fate of the methane must be destruction.

"Centralized digesters" that integrate waste from more than one livestock operation may also meet the definition of an offset project.[6]

2.3 Offset Project Operator or Authorized Project Designee

The Offset Project Operator or Authorized Project Designee is responsible for project listing, monitoring, reporting and verification. The Offset Project Operator or Authorized Project Designee must submit the information in the Regulation and in Appendices C and D of this protocol. The Offset Project Operator or Authorized Project Designee must have legal authority to implement the offset project.

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[4] Biogas control systems are commonly called digesters, which may be designed and operated in a variety of ways, from ambient temperature covered lagoons to heated lagoons to mesophilic plug flow or complete mix concrete tank digesters.

[5] The installation of a BCS at an existing livestock operation where the primary manure management system is aerobic (produces little to no methane) may result in an increase of the amount of methane emitted to the atmosphere. Thus, the BCS must digest manure that would primarily be treated in an anaerobic system in the absence of the project in order for the project to meet the definition of an offset project.

[6] The protocol does not preclude Offset Project Operators or Authorized Project Designees from co-digesting organic matter in the biogas control system. However, the additional organics could impact the nutrient properties of digester effluent, which Offset Project Operators or Authorized Project Designees should consider when assessing the offset project's associated water quality impacts.

3 Eligibility Rules

Offset projects that meet the project definition and requirements in section 2.2 must fully satisfy the eligibility requirements in the Regulation in addition to the eligibility rules listed below to be eligible to receive ARB or registry offset credits.

3.1 Location

Only projects located in the United States and its territories are eligible under this protocol. In addition, 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.

3.2 Offset Project Commencement

For this protocol, Offset Project Commencement is defined as the date at which the offset project's biogas control system (BCS) becomes operational. A BCS is considered *operational* on the date at which the system begins producing and destroying methane gas upon completion of an initial start-up period. Offset projects may always be submitted for listing prior to their commencement date.

3.3 Project Crediting Period

The crediting period for this protocol is ten years.

3.4 Additionality

Offset projects must meet the additionality requirements in the Regulation in addition to the requirements below.

3.4.1 Anaerobic Baseline - Quantification Methodology

The Offset Project Operator or Authorized Project Designee must demonstrate that the depth of the anaerobic lagoons or ponds prior to the offset project's implementation were sufficient to prevent algal oxygen production and create an oxygen-free bottom layer; which means at least 1 meter in depth.

Greenfield livestock projects (i.e., projects that are implemented at new livestock facilities that have no prior manure management system) are eligible only if the Offset Project Operator or Authorized Project Designee can demonstrate that uncontrolled anaerobic storage and/or treatment of manure is common practice in the industry and geographic region where the offset project is located.

3.5 Regulatory Compliance

As stated in the Regulation, an Offset Project Operator or Authorized Project Designee must fulfill all applicable local, regional and national requirements on environment impact assessments that apply based on the offset project location. Offset projects must also fulfill all local, regional, and national regulatory requirements that apply based on the offset project location. Offset projects are not eligible to receive ARB or registry offset credits for GHG reductions or GHG removal enhancements that are not in compliance with regulatory requirements.

4 Offset Project Boundary – Quantification Methodology

The Offset Project Boundary delineates the GHG sources, GHG sinks, and GHG reservoirs (SSRs) that shall be assessed to determine the net change in emissions associated with installing a BCS. For this protocol, the Offset Project Boundary captures sources from waste production to disposal, including off-site manure disposal. However, the calculation procedure only incorporates methane and carbon dioxide, so while nitrous oxide sources are technically within the Offset Project Boundary they are not assessed in the calculation procedure.

This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

Figure 4.1 provides a general illustration of the Offset Project Boundary, indicating which SSRs are included or excluded from the Offset Project Boundary. All SSRs within the dashed line are accounted for under this protocol.

Table 4.1 provides greater detail on each SSR and information for the SSRs and gases from the Offset Project Boundary.

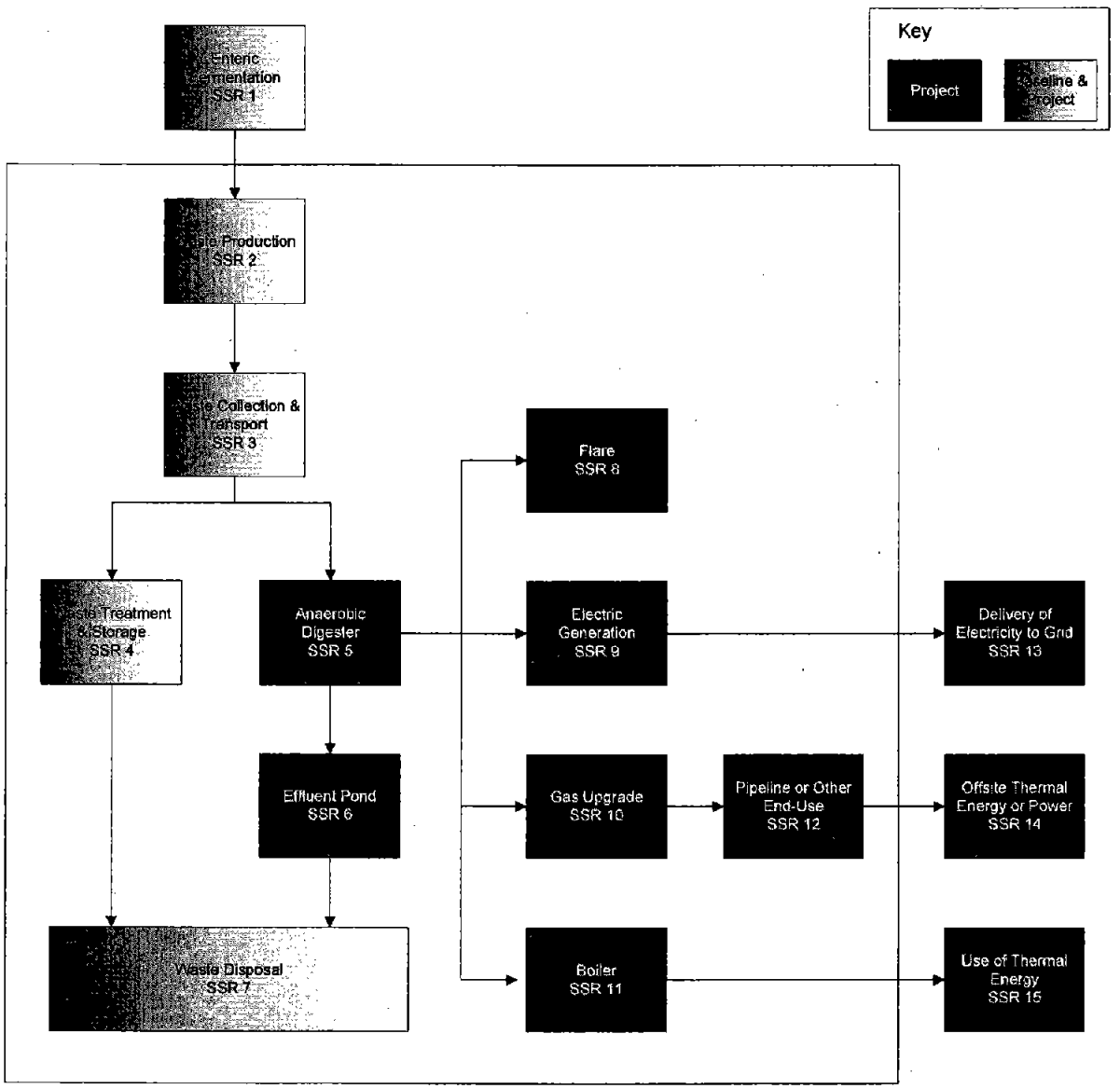


Figure 4.1. General Illustration of the Offset Project Boundary

Table 4.1 relates GHG source categories to sources and gases, and indicates inclusion in the calculation methodology. It is intended to be illustrative – GHG sources are indicative for the source category, GHGs in addition to the main GHG are also mentioned, where appropriate.

Table 4.1. Description of all GHG Sources, GHG Sinks, and GHG Reservoirs

SSR	GHG Source	Gas	Relevant to Project Baseline (B) or Offset Project (P)	Included/ Excluded
1	Emissions from enteric fermentation	CH_4	B, P	*Excluded*
2	Emissions from waste deposits in barn, milking parlor, or pasture/corral	N_2O	B, P	*Excluded*
	Emissions from mobile and stationary support equipment	CO_2	B, P	*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
3	Emissions from mechanical systems used to collect and transport waste (e.g. engines and pumps for flush systems; vacuums and tractors for scrape systems)	CO_2	B, P	*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
	Vehicle emissions (e.g. for centralized digesters)	CO_2		*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
4	Emissions from waste treatment and storage including: anaerobic lagoons, dry lot deposits, compost piles, solid storage piles, manure settling basins, aerobic treatment, storage ponds, etc.	CO_2	B, P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
	Emissions from support equipment	CO_2		*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
5	Emissions from the anaerobic digester due to biogas collection inefficiencies and venting events	CH_4	P	*Included*
6	Emissions from the effluent pond	CH_4	B, P	*Included*
		N_2O		*Excluded*
7	Emissions from land application	N_2O	B, P	*Excluded*
	Vehicle emissions for	CO_2	B, P	*Included*

SSR	GHG Source	Gas	Relevant to Project Baseline (B) or Offset Project (P)	Included/ Excluded
	land application and/or off-site transport	CH_4		*Excluded*
		N_2O		*Excluded*
8	Emissions from combustion during flaring, including emissions from incomplete combustion of biogas	CO_2	P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
9	Emissions from combustion during electric generation, including incomplete combustion of biogas	CO_2	P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
10	Emissions from equipment upgrading biogas for pipeline injection or use as CNG/LNG fuel	CO_2	P	*Included*
		CH_4		*Excluded*
		N_2O		*Excluded*
11	Emissions from combustion at boiler including emissions from incomplete combustion of biogas	CO_2	P	*Excluded*
		CH_4		*Included*
		N_2O		*Excluded*
12	Emissions from combustion of biogas by end user of pipeline or CNG/LNG, including incomplete combustion	CO_2	P	*Excluded*
		CH_4		*Excluded*
		N_2O		*Excluded*
13	Delivery and use of project electricity to grid	CO_2	P	*Excluded*
		CH_4		
		N_2O		
14	Off-site thermal energy or power	CO_2	P	*Excluded*
		CH_4		
		N_2O		
15	Use of project-generated thermal energy	CO_2	P	*Excluded*
		CH_4		
		N_2O		
16	Project construction and decommissioning emissions	CO_2	P	*Excluded*
		CH_4		
		N_2O		

5 Quantifying GHG Emission Reductions – Quantification Methodology[7]

GHG emission reductions from a livestock offset project are quantified by comparing actual project emissions to baseline emissions at the offset project site. Project baseline emissions are an estimate of the GHG emissions from GHG sources within the Offset Project Boundary that would have occurred in the absence of the livestock offset project. Project emissions are actual GHG emissions that occur at sources within the Offset Project Boundary. Project emissions must be subtracted from the project baseline emissions to quantify the offset project's total net GHG emission reductions (Equation 5.1), and the total number of GHG reductions submitted for issuance of ARB or registry offset credits must be rounded to the nearest whole ton.

The Offset Project Operators or Authorized Project Designee should take note that some equations to calculate project baseline and project emissions are run on a month-by-month basis and activity data monitoring takes place at varying levels of frequency. As applicable, monthly emissions data (for project baseline and offset project) are summed together to calculate annual GHG emission reductions.

The current methodology for quantifying the GHG emissions and GHG emission reductions associated with installing a BCS requires the use of both modeled reductions (following Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9), as well as the utilization of ex-post metered data from the BCS to be used as a check on the modeled GHG reductions.

There can be material differences between modeled methane emission reductions and the actual metered quantity of methane that is captured and destroyed by the BCS due to digester start-up periods, venting events, and other BCS operational issues. These operational issues have the potential to result in substantially less methane destruction than is modeled, leading to an overestimation of GHG reductions in the modeled case.

To address this issue and maintain consistency with international best practice, ARB requires the modeled methane emission reduction results to be compared to the ex-post metered quantity of methane that is captured and destroyed by the BCS. The lesser of the two values will represent the total methane emission reductions for the reporting period. Equation 5.1 below outlines the quantification methodology for calculating the GHG emission reductions from the installation of a BCS.[8]

[7]The entirety of Section 5 is considered a quantification method.

[8]The calculation procedure only addresses direct emissions sources and does not incorporate reductions in electricity consumption, which impacts indirect emissions associated with power plants owned and operated by entities other than the Offset Project Operator or Authorized Project Designee. Equation 5.1 accounts for any increase in CO2 if the project results in an increase in electricity consumption.

Equation 5.1. GHG Reductions from Installing a Biogas Control System

$$\text{Total GHG Reductions} = (\text{Modeled project baseline emissions}_{CH4} - \text{Project emissions}_{CH4}) + (\text{project baseline emissions}_{CO2} - \text{Project emissions}_{CO2})$$

The (*Modeled project baseline emissions* $_{CH4,}$ – *Project emissions* $_{CH4}$) term shall be calculated according to Equation 5.2 to Equation 5.4 and Equation 5.6 to Equation 5.9. The resulting aggregated quantity of methane reductions must then be compared to the ex-post quantity of methane that is metered and destroyed in the biogas collection system, as expressed in Equation 5.10. In the case that the total ex-post quantity of metered and destroyed methane is less than the modeled methane reductions, the metered quantity of destroyed methane will replace the modeled methane reductions.

Therefore, the above equation then becomes:

$$\text{Total GHG Reductions} = (\text{Total quantity of metered and destroyed methane}) + (\text{Project baseline emissions}_{CO2} - \text{Project emissions}_{CO2})$$

5.1 Quantifying Baseline Methane Emissions

Project baseline emissions represent the GHG emissions within the Offset Project Boundary that would have occurred if not for the installation of the BCS. For the purposes of this protocol, project baseline emissions must be calculated according to the manure management system in place prior to installing the BCS. This is referred to as a "continuation of current practices" project baseline scenario. Additionally, project baseline emissions must be calculated each year of the offset project.[9] The procedure assumes there is no BCS in the project baseline system. Regarding new livestock operations that install a BCS, a modeled project baseline scenario must be established using the prevailing system type in use for the geographic area, animal type, and farm size that corresponds to their operation.

The procedure to determine the modeled project baseline methane emissions follows Equation 5.2, which combines Equation 5.3 and Equation 5.4.

Equation 5.3 calculates methane emissions from anaerobic manure storage/treatment systems based on site-specific information on the mass of volatile solids degraded by the anaerobic storage/treatment system and available for methane conversion.[10] It incorporates the effects of temperature through the van't Hoff-Arrhenius '*f*' factor and accounts for the retention of volatile solids through the use of monthly assessments. Equation 5.4 is less intensive and applies to non-anaerobic storage/treatment systems. Both Equation 5.3 and Equation 5.4 reflect basic biological principles of methane production from available volatile solids, determine methane generation for each livestock category, and account for the extent to which the waste management system handles each category's manure.

[9]Conversely, under a "static baseline," the project baseline emissions would be assessed once before offset project implementation and that value would be used throughout the offset project lifetime.
[10]Anaerobic storage/treatment systems generally refer to anaerobic lagoons, or storage ponds, etc.

Equation 5.2. Modeled Project Baseline Methane Emissions

$$BE_{CH4} = \left(\sum_{S,L} BE_{CH4,AS,L} + BE_{CH4,non-AS,L} \right)$$

Where,			Units
BE_{CH4}	=	Total annual project baseline methane emissions, expressed in carbon dioxide equivalent	tCO_2e/yr
$BE_{CH4,AS,L}$	=	Total annual project baseline methane emissions from anaerobic storage/treatment systems by livestock category 'L', expressed in carbon dioxide equivalent	tCO_2e/yr
$BE_{CH4,non-AS,L}$	=	Total annual project baseline methane emissions from non-anaerobic storage/treatment systems, expressed in carbon dioxide equivalent	tCO_2e/yr

Equation 5.3. Modeled Project Baseline Methane Emissions from Anaerobic Storage/Treatment Systems

$$BE_{CH4,AS} = \sum_{L,AS} VS_{deg,AS,L} \times B_{0,L} \times 0.68 \times 0.001 \times 21$$

Where,			Units
$BE_{CH4,AS}$	=	Total annual project baseline methane emissions from anaerobic manure storage/treatment systems, expressed in carbon dioxide equivalent	tCO_2e/yr
$VS_{deg,AS,L}$	=	Annual volatile solids degraded in anaerobic manure storage/treatment system 'AS' from livestock category 'L'	kg dry matter
$B_{0,L}$	=	Maximum methane producing capacity of manure for livestock category 'L' – see Appendix A, Table A.3	m^3 CH_4/kg of VS
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

$$VS_{deg,AS,L} = \sum_{AS,L} VS_{avail,AS,L} \times f$$

Where,			Units
$VS_{deg,AS,L}$	=	Annual volatile solids degraded by anaerobic manure storage/ treatment system 'AS' by livestock category 'L'	kg dry matter
$VS_{avail,AS,L}$	=	Monthly volatile solids available for degradation from anaerobic manure storage/treatment system 'AS' by livestock category 'L'()	kg dry matter
f	=	The van't Hoff-Arrhenius factor = "the proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system"	

$$VS_{avail,AS,L} = \left(VS_L \times P_L \times MS_{AS,L} \times dpm \times 0.8\right) + \left(VS_{avail-1,AS} - VS_{deg-1,AS}\right)$$

Where,			Units
$VS_{avail,AS,L}$	=	Monthly volatile solids available for degradation in anaerobic storage/treatment system 'AS' by livestock category 'L'	kg dry matter
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
P_L	=	Annual average population of livestock category 'L' (based on monthly population data)	
$MS_{AS,L}$	=	Percent of manure sent to (managed in) anaerobic manure storage/treatment system 'AS' from livestock category 'L' [11]	%
dpm	=	Days per month	days/ month
0.8	=	System calibration factor	
$VS_{avail-1,AS}$	=	Previous month's volatile solids available for degradation in anaerobic system 'AS'	kg
$VS_{deg-1,AS}$	=	Previous month's volatile solids degraded by anaerobic system 'AS'	kg

[11] The MS value represents the percent of manure that would be sent to (managed by) the anaerobic manure storage/treatment systems in the project baseline case – as if the biogas control system was never installed.

$$f = \exp\left[\frac{E(T_2 - T_1)}{RT_1T_2}\right]$$

Where,			Units
f	=	The van't Hoff-Arrhenius factor	
E	=	Activation energy constant (15,175)	cal/mol
T_1	=	303.16	Kelvin
T_2	=	Monthly average ambient temperature (K = ℃ + 27 3). If T_2 < 5 ℃ then *f* = 0.104	Kelvin
R	=	Ideal gas constant (1.987)	cal/Kmol

Equation 5.4. Modeled Project Baseline Methane for Non-Anaerobic Storage/Treatment Systems

$$BE_{CH4,nAS} = \left(\sum_{L,S} P_L \times MS_{L,nAS} \times VS_L \times 365 \times MCF_{nAS} \times B_{0,L}\right) \times 0.68 \times 0.001 \times 21$$

Where,			Units
$BE_{CH4,nAS}$	=	Total annual project baseline methane emissions from non-anaerobic storage/treatment systems, expressed in carbon dioxide equivalent	tCO_2e/yr
P_L	=	Annual average population of livestock category 'L' (based on monthly population data)	
$MS_{L,nAS}$	=	Percent of manure from livestock category 'L' managed in non-anaerobic storage/treatment systems	%
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
365	=	Days in a year	days/yr
$MCF_{,nAS}$	=	Methane conversion factor for non-anaerobic storage/treatment system 'S' – See Appendix A	%
$B_{0,L}$	=	Maximum methane producing capacity for manure for livestock category 'L' – Appendix A, Table A.3	m^3 CH_4/kg of VS dry matter
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
0.001	=	Conversion factor from kg to metric tons	
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

Box 5.1. Daily Volatile Solids for All Livestock Categories

Consistent with international best-practice, it is recommended that appropriate VS_L values for Dairy livestock categories be obtained from the State-specific lookup table Table A.5. provided in Appendix A.

VS_L values for all other livestock can be found in Appendix A, Table A.3.

Important - Units provided for all VS values in Appendix A are in (kg/day/1000kg), in order to get VS_L in the appropriate units (kg/animal/day), the following equation must be used:

$$VS_L = VS_{table} \times \frac{Mass_L}{1000}$$

Where,

			Units
VS_L	=	Volatile solid excretion on a dry matter weight basis	kg/ animal/ day
VS_{Table}	=	Volatile solid excretion from lookup table (Table A.3 and Table A.5a. - A.5.d.)	kg/ day/ 1000kg
$Mass_L$	=	Average live weight for livestock category 'L', if site specific data is unavailable, use values from Appendix A, Table A.2	kg

5.1.1 Variables for Calculating Project Baseline Methane

The calculation procedure uses a combination of site-specific values and default factors.

Population – PL

The procedure requires the offset project to differentiate between livestock categories ('L') – e.g. lactating dairy cows, non-milking dairy cows, heifers, etc. This accounts for differences in methane generation across livestock categories (see Appendix A, Table A.2). The population of each livestock category is monitored on a monthly basis, and for Equation 5.4 averaged for an annual total population.

Volatile Solids – VS_L

This value represents the daily organic material in the manure for each livestock category and consists of both biodegradable and non-biodegradable fractions. The VS content of manure is a combination of excreted fecal material (the fraction of a livestock category's diet consumed and not digested) and urinary excretions, expressed in a dry matter weight basis (kg/animal). This protocol requires that the VS value for all livestock categories be determined as outlined in Box 5.1.

$Mass_L$

This value is the annual average live weight of the animals, per livestock category. This data is necessary because default VS values are supplied in units of kg/day/1000kg mass, therefore the average mass of the corresponding livestock category is required in order to convert the units of VS into kg/day/animal. Site specific livestock mass is preferred for all livestock categories. If site specific data is unavailable, Typical Average Mass (TAM) values can be used (Appendix A, Table A.2).

Maximum methane production – $B_{0,L}$

This value represents the maximum methane-producing capacity of the manure, differentiated by livestock category ('L') and diet. Default B_0 factors from Appendix A, Table A.3 must be used.

MS

The MS value apportions manure from each livestock category to an appropriate manure management system component ('S'). It reflects the reality that waste from the operation's livestock categories are not managed uniformly. The MS value accounts for the operation's multiple types of manure management systems. It is expressed as a percent (%), relative to the total amount of waste produced by the livestock category. As waste production is normalized for each livestock category, the percentage should be calculated as percent of population for each livestock category. For example, a dairy operation might send 85% of its milking cows' waste to an anaerobic lagoon and 15% could be deposited in a corral. In this situation an MS value of 85% would be assigned to Equation 5.3 and 15% to Equation 5.4.

Importantly, the MS value indicates where the waste would be managed in the project baseline scenario – i.e. where the manure would end-up if the digester was never installed.

Methane Conversion Factor – *MCF*

Each manure management system component has a volatile solids-to-methane conversion efficiency, which represents the degree to which maximum methane production (B_0) is achieved. Methane production is a function of the extent of anaerobic conditions present in the system, the temperature of the system, and the retention time of organic material in the system.

For anaerobic lagoons, storage ponds, liquid slurry tanks etc., this protocol requires site-specific calculation of the mass of volatile solids degraded by the anaerobic storage/treatment system. This is expressed as "degraded volatile solids" or "VS_{deg}" in Equation 5.3, which equals the system's monthly available VS-multiplied by "f," the van't Hoff-Arrhenius factor. The 'f' factor effectively converts total available VS in the anaerobic manure storage/treatment system to methane-convertible VS, based on the monthly temperature of the system.

The multiplication of "VS_{deg}" by "B_0" gives a site-specific quantification of the uncontrolled methane emissions that would have occurred in the absence of a digester – from the anaerobic storage and/or treatment system, taking into account each livestock category's contribution of manure to that system.

This method to calculate methane emissions reflects the site-specific monthly biological performance of the operation's anaerobic manure handling systems that existed pre-project, as predicted by the van't Hoff-Arrhenius equation using farm-level data on temperature, VS loading, and system VS retention time.

Default MCF values for non-anaerobic manure storage/treatment are available in Appendix A, which are used for Equation 5.4.

5.2 Quantifying Project Methane Emissions

Project emissions are actual GHG emissions that occur within the Offset Project Boundary after the installation of the BCS. Project emissions are calculated on an annual, *ex-post* basis. But like project baseline emissions, some parameters are monitored on a monthly basis. Methane emissions from manure storage and/or treatment systems other than the digester are modeled much the same as in the baseline scenario.

As shown in Equation 5.5, project methane emissions equal:

- The amount of methane created by the BCS that is not captured and destroyed by the control system, plus
- Methane from the digester effluent storage pond (if necessary), plus
- Methane from sources in the waste treatment and storage category other than the BCS and associated effluent pond. This includes all other manure treatment systems such as compost piles, solids storage, daily spread, etc.

Consistent with ACM0010 and this protocol's project baseline methane calculation approach, the formula to account for project methane emissions incorporates all

potential GHG sources within the waste treatment and storage category. Non-BCS-related sources follow the same calculation approach as provided in the project baseline methane equations. Several activity data for the variables in Equation 5.9 will be the same as those in Equation 5.2 – Equation 5.4.

Although not common under normal digester operation, it is possible that a venting event may occur due to failure of digester cover materials, the digester vessel, or the gas collection system, or due to a planned maintenance event. In the event that a system failure or planned operation results in the venting of biogas, the quantity of methane released to the atmosphere shall be estimated according to Equation 5.7.

Equation 5.5. Project Methane Emissions

$$PE_{CH4} = [(PE_{CH4,\ BCS} + PE_{CH4,\ EP} + PE_{CH4,\ non\text{-}BCS}) \times 21]$$

Where,			Units
PE_{CH4}	=	Total annual project methane emissions, expressed in carbon dioxide equivalent	tCO_2e/yr
$PE_{CH4,\ BCS}$	=	Annual methane emissions from the BCS – Equation 5.6	tCH_4/yr
$PE_{CH4,\ EP}$	=	Annual methane emissions from the BCS Effluent Pond – Equation 5.8	tCH_4/yr
$PE_{CH4,\ non\text{-}BCS}$	=	Annual methane emissions from sources in the waste treatment and storage category other than the BCS and associated Effluent Pond – Equation 5.9	tCH_4/yr
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

Equation 5.6. Project Methane Emissions from the Biogas Control System

$$PE_{CH4,BCS} = \left[\left(\mathrm{CH}_{4,\mathrm{meter}} \right) \left(\left(\frac{1}{BCE} \right) - BDE_{i,weighted} \right) \right] + CH_{4,vent,i}$$

Where,			Units
$PE_{CH4,BCS}$	=	Monthly methane emissions from the BCS, to be aggregated annually	tCH_4/yr
$CH_{4,meter}$	=	Monthly quantity of methane collected and metered	tCH_4/ month
BCE	=	Monthly methane collection efficiency of the BCS. Offset Project Operators or Authorized Project Designees use the appropriate default value provided in Table A.4	% (as a decimal)
$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month i.	% (as a decimal)
$CH_{4,vent,i}$	=	The monthly quantity of methane that is vented to the atmosphere due to BCS venting events, as quantified in Equation 5.7 below.	

$$CH_{4,meter} = F \times (520/T)^{\pi} \times (P/1)^{\pi} \times CH_{4,conc} \times 0.0423 \times 0.000454$$

Where,			Units
$CH_{4,meter}$	=	Monthly quantity of methane collected and metered[12]	tCH_4/ month
F	=	Measured volumetric flow of Biogas per month	scf/month

[12]This value reflects directly measured biogas mass flow and methane concentration in the biogas to the combustion device.

Equation 5.6. Continued

T	=	Temperature of the Biogas flow (°R = °F +459.67)	°R (Rankine)
P	=	Pressure of the Biogas flow	atm
$CH_{4,conc}$	=	Measured methane concentration of Biogas from the most recent methane concentration measurement	% (as a decimal)
0.0423	=	Density of methane gas (1atm, 60°F)	lbsCH_4/scf
0.000454	=	Conversion factor, lbs to metric tons	

** The terms (520/T) and (P/1) should be omitted if the continuous flow meter internally corrects for temperature and pressure to 60°F and 1atm.*

$$BDE_{i,weighted} = \frac{\sum_{DD}\left(BDE_{DD} \times F_{i,DD}\right)}{F_i}$$

Where,			Units
$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month i	fraction
BDE_{DD}	=	Default methane destruction efficiency of a particular destruction device 'DD'. See Appendix A for default destruction efficiencies by destruction device[13]	fraction
$F_{i,DD}$	=	Monthly flow of biogas to a particular destruction device 'DD'	scf/month
F_i	=	Total monthly measured volumetric flow of biogas to all destruction devices	scf/month

Equation 5.7. Project Methane Emissions from Venting Events

$$CH_{4,vent,i} = \left(MS_{BCS} + (F_{pw} \times t)\right) \times CH_{4,conc} \times 0.04230 \times 0.000454$$

Where,			Units
MS_{BCS}	=	Maximum biogas storage of the BCS system	SCF
F_{pw}	=	The average total flow of biogas from the digester for the entire week prior to the venting event	SCF/day
t	=	The number of days of the month that biogas is venting uncontrolled from the BCS system (can be a fraction)	days

[13] Offset Project Operators or Authorized Project Designees have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by an ARB approved source test plan, for each of the combustion devices used in the project.

Equation 5.8. Project Methane Emissions from the BCS Effluent Pond[14]

$$PE_{CH4,EP} = VS_{ep} \times B_{o,ep} \times 365 \times 0.68 \times MCF_{ep} \times 0.001$$

Where,			Units
$PE_{CH4, EP}$	=	Methane emissions from the Effluent Pond	tCH_4/yr
VS_{ep}	=	Volatile solid to effluent pond – 30% of the average daily VS entering the digester	kg/day
$B_{o,ep}$	=	Maximum methane producing capacity (of VS dry matter)[15]	m^3CH_4/kg
365	=	Days in a year	days/yr
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
MCF_{ep}	=	Methane conversion factor, Appendix A. Offset Project Operators or Authorized Project Designees shall use the *liquid slurry* MCF value for effluent ponds	Fraction
0.001	=	Conversion factor from kg to metric tons	

$$VS_{ep} = \left(\sum_{L} (VS_L \times P_L \times MS_{L,BCS}) \right) \times 0.3$$

Where,			Units
VS_L	=	VS produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
P_L	=	Annual average population of livestock category 'L' (based on monthly population data	
$MS_{L,BCS}$	=	Fraction of manure from livestock category 'L' that is managed in the BCS	fraction
0.3	=	Default value representing the amount of VS that exits the digester as a percentage of the VS entering the digester	fraction

[14] If no effluent pond exists and Offset Project Operators or Authorized Project Designees send digester effluent (VS) to compost piles or apply directly to land, for example, then the VS for these cases should also be tracked using Equation 5.8

[15] The B_o value for the project effluent pond is not differentiated by livestock category. Offset Project Operators or Authorized Project Designees could use the B_o value that corresponds with an average of the operation's livestock categories that contributes manure to the biogas control system. Supporting laboratory data and documentation need to be supplied to the verifier to justify the alternative value.

Equation 5.9. Project Methane Emissions from *Non*-BCS Related Sources[16]

$$PE_{CH4,nBCS} = \left(\sum_{L} (EF_{CH4,L}(nBCSs) \times P_L) \right) \times 0.001$$

Where,			Units
$PE_{CH4,nBCS}$	=	Methane from sources in the waste treatment and storage category other than the BCS and associated Effluent Pond	tCH_4/yr
$EF_{CH4,L}$	=	Emission factor for the livestock population from non-BCS-related sources (nBCSs, calculated below)	$kgCH_4$/ head/ yr
P_L	=	Population of livestock category 'L'	
0.001	=	Conversion factor from kg to metric tons	

$$EF_{CH4,L}(nBCSs) = (VS_L \times B_{o,L} \times 365 \times 0.68) \times \left(\sum_{S} (MCF_S \times MS_{L,S}) \right)$$

Where,			Units
$EF_{CH4,L}$	=	Methane emission factor for the livestock population from non-biogas control system related sources (nBCSs)	$kgCH_4$/ head/ yr
VS_L	=	Volatile solids produced by livestock category 'L' on a dry matter basis. *Important* – refer to Box 5.1 for using appropriate units for VS_L values from Appendix A	kg/ animal/ day
$B_{o,L}$	=	Maximum methane producing capacity for manure for livestock category 'L' (of VS dry matter), Appendix A, Table A.3	m^3 CH_4/kg
365	=	Days in a year	days/yr
0.68	=	Density of methane (1 atm, 60°F)	kg/m^3
MCF_S	=	Methane conversion factor for system component 'S', Appendix A	fraction
$MS_{L,S}$	=	Percent of manure from livestock category L that is managed in non-BCS system component 'S'	fraction

5.3 Metered Methane Destruction Comparison

As described above, all offset projects must compare the modeled methane emission reductions for the reporting period, as calculated in Equation 5.2 - Equation 5.4 and Equation 5.6 - Equation 5.9 above, with the actual metered amount of methane that is destroyed in the BCS over the same period. The lesser of the two values is to be used as the total methane emission reductions for the reporting period in question.

In order to calculate the metered methane reductions, the monthly quantity of biogas that is metered and destroyed by the BCS must be aggregated over the reporting period. In the event that an Offset Project Operator or Authorized Project Designee is reporting GHG reductions for a period of time that is less than a full year, the total modeled methane emission reductions would be aggregated over this time period and compared with the metered methane that is destroyed in the BCS over the same period of time. For example, if a project is reporting and verifying only 6 months of data, July – December for instance, the modeled emission reductions over this 6 month period would be compared to the total metered biogas destroyed over the same six month

[16]According to this protocol, non-BCS-related sources means manure management system components (system component 'S') other than the biogas control system and the BCS effluent pond (if used).

period, and the lesser of the two values would be used as the total methane emission reduction quantity for this 6 month period.

Equation 5.10 below details the metered methane destruction calculation.

Equation 5.10. Metered Methane Destruction

$$CH_{4,destroyed} = \sum_{months} (CH_{4,meter} \times BDE_{i,weighted}) \times 21$$

Where,			Units
$CH_{4,destroyed}$	=	Aggregated quantity of methane collected and destroyed during the reporting period	tCO_2e/yr
$CH_{4,meter}$	=	Monthly quantity of methane collected and metered. See Equation 5.6	tCH_4/ month
$BDE_{i,weighted}$	=	Monthly weighted average of all destruction devices used in month i[17] See Equation 5.6	% (as a decimal)
21	=	Global Warming Potential factor of methane to carbon dioxide equivalent	

Determining the methane emission reductions

- If $CH_{4,destroyed}$ is less than $(BE_{CH4} - PE_{CH4})$ as calculated in Equation 5.2 - Equation 5.4 and Equation 5.6 - Equation 5.9 for the reporting period, the methane emission reductions are equal to $CH_{4,destroyed}$
- Otherwise, the methane emission reductions are equal to $(BE_{CH4} - PE_{CH4})$

5.4 Quantifying Project Baseline and Project Carbon Dioxide Emissions

Carbon dioxide emissions associated with the project baseline or project activities include sources like electricity use by pumps and equipment, fossil fuel generators used to destroy biogas or power pumping systems or milking parlor equipment, flares, tractors that operate in barns or freestalls, on-site manure hauling trucks, or vehicles that transport manure off-site. Any net increase in emissions shall be accounted for. Use Equation 5.11 to calculate the net change in carbon dioxide emissions, or, if it can be demonstrated during verification that project carbon dioxide emissions are estimated to be equal to or less than 5% of the total project baseline emissions of methane, project baseline and project carbon dioxide emissions may be estimated. All estimates or calculations of anthropogenic carbon dioxide emissions within the Offset Project Boundary must be verified and included in GHG emission reduction calculations.

If calculations or estimates indicate that the offset project results in a net decrease in carbon dioxide emissions from grid-delivered electricity, mobile and stationary sources, then for quantification purposes the net change in these emissions must be specified as zero (i.e., $CO_{2,net} = 0$ in Equation 5.11).

[17] The Offset Project Operator or Authorized Project Designee has the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by an ARB approved source test plan, for each of the combustion devices used in the project.

Carbon dioxide emissions from the combustion of biogas are considered biogenic emissions and are excluded from the GHG Assessment Boundary.

Equation 5.11 below calculates the net change in anthropogenic carbon dioxide emissions resulting from the offset project activity.

Equation 5.11. Carbon Dioxide Emission Calculations

$CO_{2,net} = (BE_{CO2MSC} - PE_{CO2MSC})$

Where,

			Units
$CO_{2,net}$	=	Net change in anthropogenic carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources resulting from project activity	tCO_2/yr
BE_{CO2MSC}	=	Total annual baseline carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources (see equation below)	tCO_2/yr
PE_{CO2MSC}	=	Total annual project carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources (see equation below)	tCO_2/yr

All electricity consumption and stationary and mobile combustion are calculated using the equation:

$$CO_{2,MSC} = \left(\sum_c QE_c \times EF_{CO2,e} \right) + \left[\left(\sum_c QF_c \times EF_{CO2,f} \right) \times 0.001 \right]$$

Where,

			Units
$CO_{2,MSC}$	=	Anthropogenic carbon dioxide emissions from electricity consumption and mobile and stationary combustion sources	tCO_2
QE_c*	=	Quantity of electricity consumed for each emissions source 'c'	MWh/yr
$EF_{CO2,e}$	=	CO_2 emission factor *e* for electricity used; see Appendix A for emission factors by eGRID subregion	tCO_2/MWh
$EF_{CO2,f}$	=	Fuel-specific emission factor *f* from Appendix A	kg CO_2/ MMBTU or kg CO_2/ gallon
QF_c	=	Quantity of fuel consumed for each mobile and stationary emission source 'c'	MMBTU/yr or gallon/yr
0.001	=	Conversion factor from kg to metric tons	

* If total electricity being generated by project activities is > the additional electricity consumption, then QE_c shall not be accounted for in the project emissions and shall be omitted from the equation above.

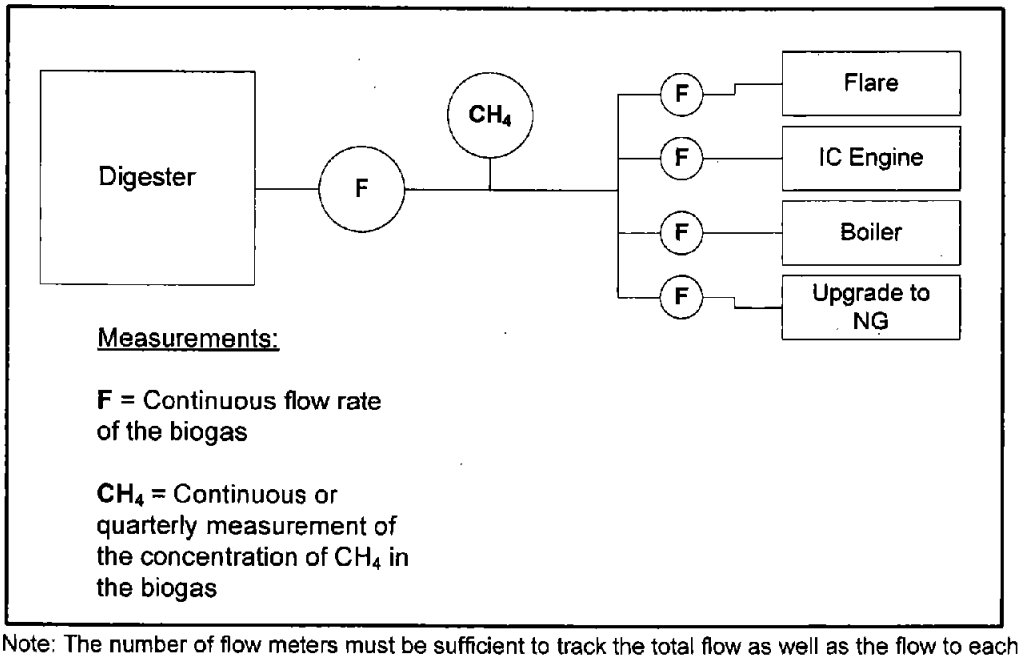
6 Offset Project Documentation and Monitoring Requirements

The Offset Project Operator or Authorized Project Designee is responsible for monitoring the performance of the offset project and operating each component of the biogas collection and destruction system in a manner consistent with the manufacturer's specifications. The methane capture and control system must be monitored with measurement equipment that directly meters:

1. The total flow of biogas, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure, prior to delivery to the destruction device(s)
2. The flow of biogas delivered to each destruction device[18], measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure
3. The fraction of methane in the biogas, measured with a continuous analyzer or, alternatively, with quarterly measurements

Flow data must be corrected for temperature and pressure at 60°F and 1 atm, either internally or by following Equation 5.6.

Figure 6.1 represents the suggested arrangement of the biogas flow meters and methane concentration metering equipment.



Note: The number of flow meters must be sufficient to track the total flow as well as the flow to each combustion device. The above example includes one more flow meter than would be necessary to achieve this objective.

[18] A single-meter may be used for multiple, identical destruction devices. In this instance, methane destruction in these units will be eligible only if all these units are monitored to be operational.

Operational activity of the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for or credited during periods in which the destruction device is not operational.

If for any reason the destruction device or the operational monitoring equipment (for example, the thermal coupler on the flare or an engine) is inoperable, all metered biogas going to the particular device shall be assumed to be released to atmosphere during the period of inoperability. During the period of inoperability, the destruction efficiency of the device must be assumed to be zero. In Equation 5.10, the monthly biogas destruction efficiency (BDE) value shall be adjusted accordingly. See Box 6.1 for an example BDE adjustment.

Box 6.1. Example BDE Adjustment

As an example, consider a situation where the primary destruction device is an open flare with a BDE of 96%, and it is found to be inoperable for a period of 5 days of a 30 day month. Assume that the total flow of biogas to the flare for the month is 3,000,000 scf, and that the total flow recorded for the 5 day period of inoperability is 500,000 SCF. In this case the monthly BDE would be adjusted as follows:

*BDE =[(0.96*2,500,000) +(0.0 * 500,000)] / 3,000,000 = 80%*

6.1 Biogas Measurement Instrument QA/QC – Quantification Methodology

All gas flow meters[19] and continuous methane analyzers must be:

- Cleaned and inspected on a quarterly basis, with the activities performed and "as found/as left condition" of the equipment documented
- Field checked by a trained professional for calibration accuracy with the percent drift documented, using either a portable instrument (such as a pitot tube)[20] or manufacturer specifications, at the end of but no more than two months prior to the end date of the reporting period[21]
- Calibrated by the manufacturer or a certified calibration service per manufacturer's specifications or every 5 years, whichever is more frequent

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.

[19]Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter.
[20]It is recommended that a professional third party calibration service be hired to perform flow meter field checks if using pitot tubes or other portable instruments, as these types of devices require professional training in order to achieve accurate readings.
[21]Instead of performing field checks, the Offset Project Operators or Authorized Project Designees may instead have equipment calibrated by the manufacturer or a certified calibration service per manufacturer's specifications, at the end of but no more than two months prior to the end date of the reporting period to meet this requirement.

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.

- For calibrations that indicate the flow meter was outside the +/- 5% accuracy threshold, the project developer shall estimate total emission reductions using i) the metered values without correction, and ii) the metered values adjusted based on the greatest calibration drift recorded at the time of calibration. The lower of the two emission reduction estimates shall be reported as the scaled emission reduction estimate.

For example, if a project conducts field checks quarterly during a year-long reporting period, only three months of data will be subject at any one time to the penalties above. However, if the Offset Project Operator or Authorized Project Designee feels confident that the meter does not require field checks or calibration on a greater than annual basis, then failed events will accordingly require the penalty to be applied to the entire year's data. Frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

In order to provide flexibility in verification, 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.

If a portable instrument is used (such as a handheld methane analyzer), the portable instrument shall be calibrated at least annually by the manufacturer or at an ISO 17025 accredited laboratory.

6.1.1 Missing Data – Quantification Methodology

In situations where the flow rate or methane concentration monitoring equipment is missing data, the Offset Project Operator or Authorized Project Designee shall apply the data substitution methodology provided in Appendix B. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermal coupler on the flare or an engine), no emission reductions can be credited for the period of inoperability.

6.2 Monitoring Parameters – Quantification Methodology

Provisions for monitoring other variables to calculate project baseline and project emissions are provided in Table 6.1. The parameters are organized by general project factors and then by the calculation methods.

Table 6.1. Project Monitoring Parameters

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
General Project Parameters					
Regulations	Offset Project Operator and Authorized Project Designee compliance with regulatory requirements relating to the manure digester offset project	Environmental regulations	n/a	Annually	information used to: 1) To demonstrate ability to meet the Legal Requirement Test – where regulation would require the installation of a BCS. 2) To demonstrate compliance with associated regulatory requirements and environmental assessments as required by the Regulation, e.g. criteria pollutant and effluent discharge limits. *Verifier:* Determine regulatory agencies responsible for regulating livestock operation; Review regulations, environmental assessments and site permits pertinent to livestock operation
L	Type of livestock categories on the farm	Livestock categories	o	Monthly	Select from list provided in Appendix A, Table A.2. *Verifier:* Review herd management software; Conduct site visit; Interview operator.
MS_L	Fraction of manure from each livestock category managed in the baseline waste handling system 'S'	Percent (%)	o	Annually	Reflects the percent of waste handled by the system components 'S' pre-project. Applicable to the entire operation. Within each livestock category, the sum of MS values (for all treatment/storage systems) equals 100%. Select from list provided in Appendix A, Table A.1. *Verifier:* Conduct site visit; Interview operator; Review baseline scenario documentation.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
P_L	Average number of animals for each livestock category	Population (# head)	o	Monthly	*Verifier*: Review herd management software; Review local air and water quality agency reporting submissions, if available (e.g. in CA, dairies with more than 500 cows report farm information to ARB).
$Mass_L$	Average live weight by livestock category	kg	o, r	Monthly	From operating records, or if on-site data is unavailable, from lookup table (Appendix A Table A.2). *Verifier*: Conduct site visit; Interview livestock operator; Review average daily gain records, operating records.
T	Average monthly temperature at location of the operation	°C	m/o	Monthly	Used for van't Hoff Calculation and for choosing appropriate MCF value. *Verifier*: Review temperature records obtained from weather service.
Baseline Methane Calculation Variables					
$B_{0,L}$	Maximum methane producing capacity for manure by livestock category	(m^3 CH_4/kgVS)	r	Annually	From Appendix A, Table A.3. *Verifier*: Verify correct value from table used.
MCF_S	Methane conversion factor for manure management system component 'S'	Percent (%)	r	Annually	From Appendix A. Differentiate by livestock category *Verifier*: Verify correct value from table used.
VS_L	Daily volatile solid production	(kg/animal/day)	r, c	Annually	Appendix A, Table A.3 and Table A.5a-d; see Box 5.1 to convert units from (kg/day/1000kg) to (kg/animal/day). *Verifier*: Ensure appropriate year's table is used; Review data units.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
VS_{avail}	Monthly volatile solids available for degradation in each anaerobic storage system, for each livestock category	kg	c, o	Monthly	Calculated value from operating records. *Verifier*: Ensure proper calculations; Review operating records.
VS_{deg}	Monthly volatile solids degraded in each anaerobic storage system, for each livestock category	kg	c, o	Monthly	Calculated value from operating records. *Verifier*: Ensure proper calculations; Review operating records.
f	van't Hoff-Arrhenius factor	n/a	c	Monthly	The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system. *Verifier*: Ensure proper calculations; Review calculation; Review temperature data.
Project Methane Calculation Variables – BCS + Effluent Pond					
$CH_{4,\ destroyed}$	Aggregated amount of methane collected and destroyed in the BCS	Metric tons of CH_4	c, m	Annually	Calculated as the collected methane times the destruction efficiency (see the '$CH_{4,meter}$' and 'BDE' parameters below) *Verifier*: Review meter reading data, confirm proper operation of the destruction device(s); Ensure data is accurately aggregated over the correct amount of time.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
$CH_{4,meter}$	Amount of methane collected and metered in BCS	Metric tons of CH_4 (tCH_4)	c, m	Monthly	Calculated from biogas flow and methane fraction meter readings (See 'F' and '$CH_{4,conc}$' parameters below). *Verifier*: Review meter reading data; Confirm proper operation and maintenance in accordance with the manufacturer's specifications; Confirm meter calibration data.
F	Monthly volume of biogas from digester to destruction devices	scf/month	m	Continuously, aggregated monthly	Measured continuously from flow meter and recorded every 15 minutes or totalized and recorded at least once daily. Data to be aggregated monthly. *Verifier*: Review meter reading data; Confirm proper aggregation of data; Confirm proper operation in accordance with the manufacturer's specifications; Confirm meter calibration data.
T	Temperature of the biogas	°R (Rankine)	m	Continuously, averaged monthly	Measured to normalize volume flow of biogas to STP. No separate monitoring of temperature is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet.
P	Pressure of the biogas	atm	m	Continuously, averaged monthly	Measured to normalize volume flow of biogas to STP. No separate monitoring of pressure is necessary when using flow meters that automatically measure temperature and pressure, expressing biogas volumes in normalized cubic feet.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
$CH_{4,conc}$	Methane concentration of biogas	Percent (%)	m	Quarterly	Use a direct sampling approach that yields a value with at least 95% confidence. Samples to be taken at least quarterly. Calibrate monitoring instrument in accordance with the manufacturer's specifications. *Verifier*: Review meter reading data; Confirm proper operation in accordance with the manufacturer's specifications.
BDE	Methane destruction efficiency of destruction device(s)	Percent (%)	r, c	Monthly	Reflects the actual efficiency of the system to destroy captured methane gas – accounts for different destruction devices. See Equation 5.6. *Verifier*: Confirm evidence of proper and continuous operation in accordance with the manufacturer's specifications.
BCE	Biogas capture efficiency of the anaerobic digester, accounts for gas leaks.	Percent (%)	r	Annually	Use default value from Table A.4 *Verifier*: Review operation and maintenance records to ensure proper functionality of BCS.
VS_{ep}	Average daily volatile solid of digester effluent to effluent pond	kg/day	c	Annually	If project uses effluent pond, equals 30% of the average daily VS entering the digester (From ACM0010 -V2 Annex I). *Verifier*: Review VS_{ep} calculations.
$MS_{L,BCS}$	Fraction of manure from each livestock category managed in the BCS	Percent (%)	o	Annually	Used to determine the total VS entering the digester. The percentage should be tracked in operational records. *Verifier*: Check operational records and conduct site visit.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
Bo_{ep}	Maximum methane producing capacity for manure to effluent pond	(m^3 CH_4/kgVS)	c	Annually	An average of the Bo_{ep} value of the operation's livestock categories that contributes manure to the BCS. *Verifier:* Check calculation.
MCF_{ep}	Methane conversion factor for BCS effluent pond	Percent (%)	r	Annually	Referenced from Appendix A. The Offset Project Operators or Authorized Project Designee should use the *liquid slurry* MCF value. *Verifier:* Verify value from table.
MS_{BCS}	The maximum biogas storage of the BCS system	scf	r	Annually	Obtained from digester system design plans. Necessary to quantify the release of methane to the atmosphere due to an uncontrolled venting event.
F_{pw}	The average flow of biogas from the digester for the entire week prior to the uncontrolled venting event	scf/day	m	Weekly	The average flow of biogas can be determined from the daily records from the previous week.
t	The number of days of the month that biogas is venting uncontrolled from the project's BCS.	Days	m, o	Monthly	The number of days of the month that biogas is venting uncontrolled from the project's BCS.

Parameter	Description	Data unit	calculated (c) measured (m) reference(r) operating records (o)	Measurement frequency	Comment
Project Methane Calculation Variables – Non-BCS Related Sources					
$MS_{L,S}$	Fraction of manure from each livestock category managed in non-anaerobic manure management system component 'S'	Percent (%)	o	Monthly	Based on configuration of manure management system, differentiated by livestock category. *Verifier*: Conduct site visit; Interview operator.
$EF_{CH4,L}$ *(nBCSs)*	Methane emission factor for the livestock population from non-BCS-related sources	($kgCH_4$/head/year)	c	Annually	Emission factor for all non-BCS storage systems, differentiated by livestock category. See Equation 5.9. *Verifiers*: Review calculation, operation records.
Baseline and Project CO_2 Calculation Variables					
$EF_{CO2,f}$	Fuel-specific emission factor for mobile and stationary combustion sources	kg CO_2/MMBTU or kg CO_2/gallon	r	Annually	Refer to Appendix A for emission factors. If biogas produced from digester is used as an energy source, the emission factor is zero. *Verifier*: Review emission factors.
QF_c	Quantity of fuel used for mobile/stationary combustion sources	MMBTU/year or gallon/year	o, c	Annually	Fuel used by project for manure collection, transport, treatment/storage, and disposal, and stationary combustion sources including supplemental fossil fuels used in combustion device. *Verifier*: Review operating records and quantity calculation.
$EF_{CO2,e}$	Emission factor for electricity used by project	tCO2/MWh	r	Annually	Refer to Appendix A for emission factors. If biogas produced from digester is used to generate electricity consumed, the emission factor is zero. *Verifier*: Review emission factors.
QE_c	Quantity of electricity consumed	MWh/year	o, c	Annually	Electricity used by project for manure collection, transport, treatment/storage, and disposal. *Verifier*: Review operating records and quantity calculation.

7 Reporting Parameters

General requirements for reprinting and record retention are included in the Regulation. This section includes additional requirements specific to this protocol. A priority of this protocol is to facilitate consistent and transparent information disclosure by Offset Project Operators or Authorized Project Designees.

7.1 Annual Reporting Requirements

The Offset Project Operators or Authorized Project Designees must submit an Offset Project Data Report according to the requirements in the Regulation. The Offset Project Data Report must include the information listed in the Regulation and this protocol and cover a single Reporting Period. See the Regulation and Appendix D for specific requirements.

7.2 Document Retention

The Offset Project Operators or Authorized Project Designees is required to keep all documentation and information outlined in the Regulation and this protocol. Record retention requirements are set forth in the Regulation.

System Information that should be retained by the Offset Project Operator or Authorized Project Designee should include, but is not limited to:

- All data inputs for the calculation of the project baseline emissions and project emission reductions
- CO_2e annual tonnage calculations
- Relevant sections of the BCS operating permits
- BCS information (installation dates, equipment list, etc.)
- Biogas flow meter information (model number, serial number, manufacturer's calibration procedures)
- Cleaning and inspection records for all biogas meters
- Field check results for all biogas meters
- Calibration results for all biogas meters
- Methane monitor information (model number, serial number, calibration procedures)
- Biogas flow data (for each flow meter)
- Biogas temperature and pressure readings (only if flow meter does not correct for temperature and pressure automatically)
- Methane concentration monitoring data
- Destruction device monitoring data (for each destruction device)
- Destruction device, methane monitor and biogas flow monitor information (model numbers, serial numbers, calibration procedures)
- All maintenance records relevant to the BCS, monitoring equipment, and destruction devices

If using a calibrated portable gas analyzer for CH_4 content measurement:

- Date, time, and location of methane measurement

- Methane content of biogas (% by volume) for each measurement
- Methane measurement instrument type and serial number
- Date, time, and results of instrument calibration
- Corrective measures taken if instrument does not meet performance specifications

See the Regulation for record-keeping requirements.

7.3 Verification Cycle

Offset project verification schedules are set forth in the Regulation.

8 Glossary of Terms[22]

Anaerobic	Pertaining to or caused by the absence of oxygen.
Biogas	Gas that is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including, but not limited to, 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.
Biogas control system (BCS)	A system designed to capture and destroy the biogas that is produced by the anaerobic treatment and/or storage of livestock manure and/or other organic material. Commonly referred to as a "digester."
Biogenic CO_2 emissions	CO_2 emissions resulting from the combustion and/or aerobic decomposition of organic matter. Biogenic emissions are considered to be a natural part of the carbon cycle, as opposed to anthropogenic emissions.

[22] For terms not defined in this section, the definitions in the Regulation apply.

Emission factor	A unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. metric tons of carbon dioxide emitted per barrel of fossil fuel burned).
Flare	A destruction device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.
Livestock project	Installation of a biogas control system that, in operation, causes a decrease in GHG emissions from the baseline scenario through destruction of the methane component of biogas.
Methane (CH_4)	A potent GHG with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.
MMBtu	One million British thermal units.
Mobile combustion	Emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g. cars, trucks, tractors, dozers, etc.).
Stationary combustion source	A stationary source of emissions from the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.
van't Hoff-Arrhenius factor	The proportion of volatile solids that are biologically available for conversion to methane based on the monthly temperature of the system.

9 References

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Appendix A Emission Factor Tables – Quantification Methodology

Table A.1. Manure Management System Components

System	Definition
Pasture/Range/ Paddock	The manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.
Daily spread	Manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.
Solid storage	The storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.
Dry lot	A paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.
Liquid/Slurry	Manure is stored as excreted or with some minimal addition of water in either tanks or earthen ponds outside the animal housing, usually for periods less than one year.
Uncovered anaerobic lagoon	A type of liquid storage system designed and operated to combine waste stabilization and storage. Lagoon supernatant is usually used to remove manure from the associated confinement facilities to the lagoon. Anaerobic lagoons are designed with varying lengths of storage (up to a year or greater), depending on the climate region, the volatile solids loading rate, and other operational factors. The water from the lagoon may be recycled as flush water or used to irrigate and fertilize fields.
Pit storage below animal confinements	Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility, usually for periods less than one year.
Anaerobic digester	Animal excreta with or without straw are collected and anaerobically digested in a large containment vessel or covered lagoon. Digesters are designed and operated for waste stabilization by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and flared or used as a fuel.
Burned for fuel	The dung and urine are excreted on fields. The sun dried dung cakes are burned for fuel.
Cattle and Swine deep bedding	As manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.
Composting – In-vessel*	Composting, typically in an enclosed channel, with forced aeration and continuous mixing.
Composting – Static pile*	Composting in piles with forced aeration but no mixing.
Composting – Intensive windrow*	Composting in windrows with regular (at least daily) turning for mixing and aeration.
Composting – Passive windrow*	Composting in windrows with infrequent turning for mixing and aeration.
Aerobic treatment	The biological oxidation of manure collected as a liquid with either forced or natural aeration. Natural aeration is limited to aerobic and facultative ponds and wetland systems and is due primarily to photosynthesis. Hence, these systems typically become anoxic during periods without sunlight.

*Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production.

Table A.2. Livestock Categories and Typical Average Mass (TAM)

Livestock Category (L)	Livestock Typical Average Mass (TAM) in kg
Dairy cows (on feed)	604
Non-milking dairy cows (on feed)	684
Heifers (on feed)	476
Bulls (grazing)	750
Calves (grazing)	118
Heifers (grazing)	420
Cows (grazing)	533
Nursery swine	12.5
Grow/finish swine	70
Breeding swine	198

Table A.3. Volatile Solids and Maximum Methane Potential by Livestock Category

Livestock category (L)	VS_L (kg/day/1,000 kg mass)	$B_{o,L}$ (m^3 CH_4/kg VS added)
Dairy cows	See Appendix A, Table A.5.	0.24
Non-milking dairy cows	5.56	0.24
Heifers	See Appendix A, Table A.5.	0.17
Bulls (grazing)	6.04	0.17
Calves (grazing)	6.41	0.17
Heifers (grazing)	See Appendix A, Table A.5.	0.17
Cows (grazing)	See Appendix A, Table A.5.	0.17
Nursery swine	8.89	0.48
Grow/finish swine	5.36	0.48
Breeding swine	2.71	0.35

Table A.4. Biogas Collection Efficiency (BCE) by Digester Type

Digester Type	Cover Type	Biogas Collection Efficiency (BCE) as a decimal
Covered Anaerobic Lagoon	Bank-to-Bank, impermeable	0.95 (95%)
Complete mix, plug flow, or fixed film digester	Enclosed vessel	0.98 (98%)

Table A.5. 2007 Volatile Solid (VS) Default Values for Dairy Cows, Heifers, Heifers-Grazing and Cows-Grazing by State (kg/day/1000 kg mass)

State	VS Dairy Cow	VS Heifer	VS Heifer–Grazing	VS Cows-Grazing
Alabama	8.02	7.42	7.82	7.02
Alaska	8.18	7.42	10.08	9.02
Arizona	10.55	7.42	10.41	9.02
Arkansas	7.11	8.22	7.87	7.00
California	8.98	7.42	7.92	6.85
Colorado	9.11	7.42	7.65	6.46
Connecticut	8.22	6.70	7.66	6.90
Delaware	7.60	6.70	7.89	6.90
Florida	8.40	7.42	7.77	7.02
Georgia	8.80	7.42	7.89	7.02
Hawaii	7.52	7.42	10.30	9.02
Idaho	10.34	7.42	10.80	9.02
Illinois	8.08	7.42	*8.11*	6.91
Indiana	*8.49*	7.42	*8.01*	6.91
Iowa	*8.43*	7.42	*8.20*	6.91
Kansas	*8.35*	7.42	*7.68*	6.46
Kentucky	7.70	7.42	7.97	7.02
Louisiana	6.88	8.22	7.75	7.00
Maine	7.88	6.70	7.66	6.90
Maryland	7.94	6.70	7.85	6.90
Massachusetts	7.69	6.70	7.78	6.90
Michigan	9.05	7.42	7.95	6.91
Minnesota	8.13	7.42	8.05	6.91
Mississippi	8.09	7.42	7.85	7.02
Missouri	7.21	7.42	7.88	6.91
Montana	8.05	7.42	7.21	6.46
Nebraska	*7.98*	7.42	*7.64*	6.46
Nevada	*9.75*	7.42	10.5	9.02
New Hampshire	8.58	*6.70*	7.78	6.90
New Jersey	7.64	6.70	7.92	6.90
New Mexico	10.03	7.42	10.64	9.02
New York	8.24	6.70	7.99	6.90
North Carolina	9.07	7.42	*7.85*	7.02
North Dakota	*7.29*	7.42	*7.40*	6.46
Ohio	*7.94*	7.42	*7.94*	6.91
Oklahoma	*8.04*	8.22	*8.09*	7.00
Oregon	9.49	7.42	10.61	9.02
Pennsylvania	8.27	6.70	8.03	6.90
Rhode Island	7.56	6.70	7.66	6.90
South Carolina	8.73	7.42	7.85	7.02
South Dakota	8.24	7.42	7.50	6.46
Tennessee	8.21	7.42	7.92	7.02
Texas	9.19	8.22	8.20	7.00
Utah	9.75	7.42	10.58	9.02
Vermont	*7.95*	6.70	7.92	6.90
Virginia	8.64	7.42	7.95	7.02
Washington	10.54	7.42	10.87	9.02
West Virginia	7.29	6.70	7.82	6.90
Wisconsin	8.25	7.42	7.88	6.91
Wyoming	8.13	7.42	7.34	6.46

Table A.6.a IPCC 2006 Methane Conversion Factors by Manure Management System Component/Methane Source 'S'

MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS																					
System[a]		MCFs by average annual temperature (°C)																			Source and comments
		Cool					Temperate											Warm			
		≤ 10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	≥ 28	
Pasture/Range/Paddock		1.0%					1.5%											2.0%			Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994).
Daily spread		0.1%					0.5%											1.0%			Hashimoto and Steed (1993).
Solid storage		2.0%					4.0%											5.0%			Judgment of IPCC Expert Group in combination with Amon et al. (2001), which shows emissions of approximately 2% in winter and 4% in summer. Warm climate is based on judgment of IPCC Expert Group and Amon et al. (1998).
Dry lot		1.0%					1.5%											2.0%			Judgment of IPCC Expert Group in combination with Hashimoto and Steed (1994).
Liquid / Slurry	With natural crust cover	10 %	11 %	13 %	14 %	15 %	17 %	18 %	20 %	22 %	24 %	26 %	29 %	31 %	34 %	37 %	41 %	44 %	48 %	50 %	Judgment of IPCC Expert Group in combination with Mangino et al. (2001) and Sommer (2000). The estimated reduction due to the crust cover (40%) is an annual average value based on a limited data set and can be highly variable dependent on temperature, rainfall, and composition. When slurry tanks are used as fed-batch storage/digesters, MCF should be calculated according to Formula 1.
	W/out natural crust cover	17 %	19 %	20 %	22 %	25 %	27 %	29 %	32 %	35 %	39 %	42 %	46 %	50 %	55 %	60 %	65 %	71 %	78 %	80 %	Judgment of IPCC Expert Group in combination with Mangino et al. (2001). When slurry tanks are used as fed-batch storage/digesters, MCF should be calculated according to Formula 1.

Table A.6.a Continued

MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS																					
System[a]		MCFs by average annual temperature (°C)																			Source and comments
		Cool					Temperate											Warm			
		≤ 10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	≥ 28	
Uncovered anaerobic lagoon		66%	68%	70%	71%	73%	74%	75%	76%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%	80%	Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Uncovered lagoon MCFs vary based on several factors, including temperature, retention time, and loss of volatile solids from the system (through removal of lagoon effluent and/or solids).
Pit storage below animal confinements	< 1 month	3%					3%											3%			Judgment of IPCC Expert Group in combination with Moller et al. (2004) and Zeeman (1994). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions. When pits used as fed-batch storage/digesters, MCF should be calculated according to Formula 1.
	> 1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%	Judgment of IPCC Expert Group in combination with Mangino et al. (2001). Note that the ambient temperature, not the stable temperature is to be used for determining the climatic conditions. When pits used as fed-batch storage/digesters, MCF should be calculated according to Formula 1.

Table A.6.a Continued

MCF VALUES BY TEMPERATURE FOR MANURE MANAGEMENT SYSTEMS																					
System[a]		MCFs by average annual temperature (°C)																			Source and comments
		Cool					Temperate											Warm			
		≤ 10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	≥ 28	
Anaerobic digester		0-100%					0-100%											0-100%			Should be subdivided in different categories, considering amount of recovery of the biogas, flaring of the biogas and storage after digestion. Calculation with Formula 1.
Burned for fuel		10%					10%											10%			Judgment of IPCC Expert Group in combination with Safley et al. (1992).
Cattle and Swine deep bedding	< 1 month	3%					3%											30%			Judgment of IPCC Expert Group in combination with Moller et al. (2004). Expect emissions to be similar, and possibly greater, than pit storage, depending on organic content and moisture content.
Cattle and Swine deep bedding (cont.)	> 1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	90%	Judgment of IPCC Expert Group in combination with Mangino et al. (2001).
Composting - In-vessel[b]		0.5%					0.5%											0.5%			Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are less than half of solid storage. Not temperature dependant.
Composting - Static pile[b]		0.5%					0.5%											0.5%			Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are less than half of solid storage. Not temperature dependant.

Table A.6.a Continued

Composting - Intensive windrow[b]	0.5%	1.0%	1.5%	Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are slightly less than solid storage. Less temperature dependant.
Composting – Passive windrow[b]	0.5%	1.0%	1.5%	Judgment of IPCC Expert Group and Amon et al. (1998). MCFs are slightly less than solid storage. Less temperature dependant.
Aerobic treatment	0%	0%	0%	MCFs are near zero. Aerobic treatment can result in the accumulation of sludge which may be treated in other systems. Sludge requires removal and has large VS values. It is important to identify the next management process for the sludge and estimate the emissions from that management process if significant.

a Definitions for manure management systems are provided in Table A.1.
b Composting is the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production.

Table A.6.b. Biogas Destruction Efficiency Default Values by Destruction Device

If available, the actual source test results for the measured methane destruction efficiency shall be used in place of the default methane destruction efficiency. Otherwise, the Offset Project Operators or Authorized Project Designees has the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the destruction devices used in the project case performed on an annual basis.

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

Table A.7. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / Short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / Standard cubic foot**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / Standard cub. ft.**
975 to 1,000 Btu / Std cubic foot	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / Std cubic foot	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / Std cubic foot	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / Std cubic foot	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / Std cubic foot	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / Std cubic foot	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / Barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt & Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2 & 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 & 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401 deg. F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401 deg. F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders, Stationary Combustion Guidance (2008), Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable). Heat content factors are based on higher heating values (HHV).

Table A.8. CO_2 Electricity Emission Factors

eGRID subregion acronym	eGRID subregion name	Annual output emission rates	
		(lb CO_2/MWh)	(metric ton CO_2/MWh)*
AKGD	ASCC Alaska Grid	1,232.36	0.559
AKMS	ASCC Miscellaneous	498.86	0.226
AZNM	WECC Southwest	1,311.05	0.595
CAMX	WECC California	724.12	0.328
ERCT	ERCOT All	1,324.35	0.601
FRCC	FRCC All	1,318.57	0.598
HIMS	HICC Miscellaneous	1,514.92	0.687
HIOA	HICC Oahu	1,811.98	0.822
MROE	MRO East	1,834.72	0.832
MROW	MRO West	1,821.84	0.826
NEWE	NPCC New England	927.68	0.421
NWPP	WECC Northwest	902.24	0.409
NYCW	NPCC NYC/Westchester	815.45	0.370
NYLI	NPCC Long Island	1,536.80	0.697
NYUP	NPCC Upstate NY	720.80	0.327
RFCE	RFC East	1,139.07	0.517
RFCM	RFC Michigan	1,563.28	0.709
RFCW	RFC West	1,537.82	0.698
RMPA	WECC Rockies	1,883.08	0.854
SPNO	SPP North	1,960.94	0.889
SPSO	SPP South	1,658.14	0.752
SRMV	SERC Mississippi Valley	1,019.74	0.463
SRMW	SERC Midwest	1,830.51	0.830
SRSO	SERC South	1,489.54	0.676
SRTV	SERC Tennessee Valley	1,510.44	0.685
SRVC	SERC Virginia/Carolina	1,134.88	0.515

Source: U.S. EPA eGRID2007, Version 1.1 Year 2005 GHG Annual Output Emission Rates (December 2008).
* Converted from lbs CO_2/MWh to metric tons CO_2/MWH using conversion factor 1 metric ton = 2,204.62 lbs.

Appendix B Data Substitution – Quantification Methodology

This appendix shows how to calculate GHG emission reductions when data integrity has been compromised either due to missing data points or a failed calibration. No data substitution is permissible for equipment such as thermocouples which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters.

B.1 Missing Data

ARB expects that offset projects will have continuous, uninterrupted data for the entire verification period. However, ARB recognizes that unexpected events or occurrences may result in brief data gaps.

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. 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.

Further, 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.

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 or upper confidence limit of the 24 hours prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted and no credits may be generated

Note: It is conservative to use the upper confidence limit when calculating emissions from the BCS (Equation 5.6); however it is conservative to use the lower confidence limit when calculating the total amount of methane that is destroyed in the BCS Equation 5.10.

Appendix C Offset Project Listing Information

All information, if applicable, must be completed, even if the answer is also provided elsewhere;

1. Offset project name
2. Offset Project Operator or Authorized Project Designee
3. Facility owner
4. Technical consultants
5. Other parties with a material interest
6. Date of form completion
7. Form completed by (name, organization)
8. Offset project description: 1-2 paragraphs (including type of digester & method of destruction)
9. Offset project site address (including all governing jurisdictions & lat/lon)
10. Name & address of animal facility (if different from project site)
11. Description of type of facility (e.g. dairy, swine, etc.)
12. Offset project commencement date
13. Reporting period
14. Have any GHG reductions associated with the offset project ever been registered with or claimed by another registry or program, or sold to a third party prior to our listing? If yes, identify the registry or program (vintage and reporting period)
15. Is this offset project being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate? If yes, explain.

Appendix D Offset Project Data Report Information

1. Offset project name
2. Offset Project Operator or Authorized Project Designee
3. Report date
4. Contact information for Offset Project Operator or Authorized Project Designee
    a. Address, email, phone number
5. Name of individual completing report
6. Reporting period
7. Does offset project meet all local, state, or federal regulatory requirements
8. Offset project commencement date
9. Facility name and location
10. Is all the information in the offset project listing still accurate? If not provided updates.
11. Project baseline emissions
12. Project emissions
13. Total GHG reductions

October 2011

California Environmental Protection Agency

AIR RESOURCES BOARD

Compliance Offset Protocol U.S. Forest Projects

Adopted: [INSERT Date of Board Adoption]

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Abbreviations and Acronyms

ARB	Air Resources Board
C	Carbon
CAR	Climate Action Reserve
CH_4	Methane
CO_2	Carbon dioxide
FIA	Forest Inventory and Analysis Program of the U.S. Forest Service
GHG	Greenhouse gas
lb	Pound
IFM	Improved Forest Management
N_2O	Nitrous oxide
Regulation	Cap-and-Trade Regulation, title 17, California Code of Regulations, sections 95800 et seq.
SSR	GHG Sources, GHG Sinks, and GHG Reservoirs
USFS	United States Forest Service

1 Introduction

The Compliance Offset Protocol U.S. Forest Projects (Forest Offset Protocol) provides requirements and methods for quantifying the net climate benefits of activities that sequester carbon on forestland. The protocol provides offset project eligibility rules; methods to calculate an offset project's net effects on greenhouse gas (GHG) emissions and removals of CO_2 from the atmosphere (removals); procedures for assessing the risk that carbon sequestered by a project may be reversed (i.e. released back to the atmosphere); and approaches for long term project monitoring and reporting. The goal of this protocol is to ensure that the net GHG reductions and GHG removal enhancements caused by an offset project are accounted for in a complete, consistent, transparent, accurate, and conservative manner and may therefore be reported as the basis for issuing ARB or registry offset credits. The protocol is built off of The Climate Action Reserve's Forest Project Protocol Version 3.2.[1]

Offset Project Operators or Authorized Project Designees must use this protocol to quantify and report GHG reductions and GHG removal enhancements. The protocol provides eligibility rules, methods to quantify GHG reductions, project-monitoring instructions, and procedures for reporting Offset Project Data Reports. Additionally, all offset projects must submit to independent verification by ARB-accredited verification bodies. Requirements for verification bodies to verify Offset Project Data Reports are provided in the Cap-and-Trade Regulation (Regulation).

AB 32 exempts quantification methodologies from the Administrative Procedure Act (APA)[2]; 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 to be 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 quantification methodologies 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.

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[1] Climate Action Reserve (CAR 2010) Forest Project Project Protocol Version 3.2. August 31, 2010. http://www.climateactionreserve.org/wpcontent/uploads/2009/03/Forest_Project_Protocol_Version_3.2.pdf/ (accessed September 9, 2010)

[2] Health and Safety Code section 38571.

1.1 About Forests, Carbon Dioxide, and Climate Change

Forests have the capacity to both emit and sequester carbon dioxide (CO_2), a leading greenhouse gas that contributes to climate change. Trees, through the process of photosynthesis, naturally absorb CO_2 from the atmosphere and store the gas as carbon in their biomass, i.e. trunk (bole), leaves, branches, and roots. Carbon is also stored in the soils that support the forest, as well as the understory plants and litter on the forest floor. Wood products that are harvested from forests can also provide long term storage of carbon.

When trees are disturbed, through events like fire, disease, pests or harvest, some of their stored carbon may oxidize or decay over time releasing CO_2 into the atmosphere. The quantity and rate of CO_2 that is emitted may vary, depending on the particular circumstances of the disturbance. Forests function as reservoirs in storing CO_2. Depending on how forests are managed or impacted by natural events, they can be a net source of emissions, resulting in a decrease to the reservoir, or a net sink, resulting in an increase of CO_2 to the reservoir. In other words, forests may have a net negative or net positive impact on the climate.

Through sustainable management and protection, forests can also play a positive and significant role to help address global climate change. The Forest Offset Protocol is designed to address the forest sector's unique capacity to sequester, store, and emit CO_2 and to facilitate the positive role that forests can play to address climate change.

2 Forest Project Definitions and Requirements

For the purposes of this protocol, a Forest Project is a planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.

A glossary of terms related to Forest Projects is provided in Section 11 of this protocol. Throughout the protocol, important defined terms are capitalized (e.g. "Reforestation Project"). For terms not defined in Section 11, the definitions in the Regulation apply.

2.1 Project Types

The following types of Forest Project activities are eligible:

2.1.1 Reforestation

A Reforestation Project involves restoring tree cover on land that is not at optimal stocking levels and has minimal short-term (30-years) commercial opportunities. A Reforestation Project is only eligible if it can fully satisfy the eligibility rules in the Regulation and:

1. The project involves tree planting or removal of impediments to natural reforestation, on land that:
    a. Has had less than 10 percent tree canopy cover for a minimum of 10 years; or
    b. Has been subject to a Significant Disturbance that has removed at least 20 percent of the land's above-ground live biomass in trees.
2. No rotational harvesting of reforested trees or any harvesting of pre-existing carbon in live trees occurs during the first 30 years after offset project commencement unless such harvesting is needed to prevent or reduce an imminent threat of disease. Such harvesting may only occur if the Offset Project Operator or Authorized Project Designee provides a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that the harvesting is necessary to prevent or mitigate disease.
3. The tree planting, or removal of impediments to natural reforestation, does not follow a commercial harvest of healthy live trees that has occurred in the Project Area within the past 10 years, or since the occurrence of a Significant Disturbance, whichever period is shorter.
4. The offset project does *not* employ broadcast fertilization.
5. The offset project does not take place on land that was part of a previously listed and verified Forest Project, unless the previous Forest Project was terminated due to an Unintentional Reversal (see Section 7) or is an early action offset project transitioning to this protocol according to the provisions of the Regulation and this protocol.
6. If the offset project was an offset project in a voluntary offset program, the offset project can demonstrate it has met all legal and contractual requirements to allow it to terminate its project relationship with the voluntary offset program and be listed using this compliance offset protocol.

Reforestation Projects on both private and public lands, excluding federal lands that are not included in the categories of land listed in section 3.6 of this protocol, are eligible.

2.1.2 Improved Forest Management

An Improved Forest Management Project involves management activities that maintain or increase carbon stocks on forested land relative to baseline levels of carbon stocks, as defined

in Section 6.2 of this protocol. An Improved Forest Management Project is only eligible if it can fully satisfy the eligibility rules in the Regulation and:

1. The offset project takes place on land that has greater than 10 percent tree canopy cover.
2. The offset project employs natural forest management practices, as defined in Section 3.8.2 of this protocol.
3. The offset project does *not* employ broadcast fertilization.
4. The offset project does not take place on land that was part of a previously listed and verified Forest Project, unless the previous Forest Project was terminated due to an Unintentional Reversal (see Section 7) or is an early action offset project transitioning to this protocol according to the provisions of the Regulation and this protocol.
5. If the offset project was an offset project in a voluntary offset program, the offset project can demonstrate it has met all legal and contractual requirements to allow it to terminate its project relationship with the voluntary offset program and be listed using this compliance offset protocol.

Eligible management activities may include, but are not limited to:

- Increasing the overall age of the forest by increasing rotation ages.
- Increasing the forest productivity by thinning, diseased, and suppressed trees.
- Managing competing brush and short-lived forest species.
- Increasing the stocking of trees on understocked areas.
- Maintaining stocks at a high level.

Improved Forest Management Projects on both private and public lands, excluding federal lands that are not included in the categories of land listed in section 3.6 of this protocol, are eligible.

2.1.3 Avoided Conversion

An Avoided Conversion Project involves preventing the conversion of forestland to a non-forest land use by dedicating the land to continuous forest cover through a Qualified Conservation Easement or transfer to public ownership, excluding transfer to federal ownership. An Avoided Conversion Project is only eligible if it can fully satisfy the eligibility rules in the Regulation and:

1. It can be demonstrated that there is a significant threat of conversion of project land to a non-forest land use by following the requirements for establishing the project's baseline in Section 6.3 of this protocol.
2. The offset project does *not* employ broadcast fertilization.
3. The offset project does not take place on land that was part of a previously listed and verified Forest Project, unless the previous Forest Project was terminated due to an Unintentional Reversal (see Section 7) or is an early action offset project transitioning to this protocol according to the provisions of the Regulation and this protocol.
4. If the offset project was an offset project in a voluntary offset program, the offset project can demonstrate it has met all legal and contractual requirements to allow it to terminate its project relationship with the voluntary offset program and be listed using this compliance offset protocol.

An Avoided Conversion Project may involve tree planting and harvesting as part of the project activity.

Avoided Conversion Projects are eligible only on lands that are privately owned prior to offset project commencement.

2.2 Forest Owners

A Forest Owner is the owner of any interest in the real (as opposed to personal) property involved in a Forest 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 Project. In some cases, one entity may own the land 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 Forest Owners, however, a single Forest Owner must be identified as the Offset Project Operator.

The Offset Project Operator is responsible for undertaking, listing, and verifying a Forest Project, however, all Forest Owner(s) are ultimately responsible for all Forest Project commitments. The Offset Project Operator may identify an Authorized Project Designee pursuant to §95974 of the Regulation, to assist or consult with implementation of the Forest Project. All information submitted to ARB or an Offset Project Registry shall reference the Offset Project Operator and all Forest Owner(s) who are ultimately responsible for the accuracy and completeness of the information submitted.

3 Eligibility Rules and Other Requirements

In addition to the definitions and requirements described in Section 2, Forest Projects must meet several other criteria and conditions to be eligible for listing, and must adhere to requirements in the Regulation and requirements related to duration and crediting periods.

3.1 Additionality

ARB and registry offsets credits must be generated by projects that yield surplus GHG emission reductions or removal enhancements that exceed any GHG reductions or removals otherwise required by law or regulation, or any GHG reduction or removal that would otherwise occur in a conservative Business-As-Usual Scenario. Forest Projects must satisfy the following to be considered additional:

1. Forest Projects must achieve GHG reductions or GHG removal enhancements above and beyond any GHG reductions or GHG removal enhancements that would result from compliance with any federal, state, or local law, regulation or ordinance. Forest Projects must also achieve GHG reductions and GHG removal enhancements above and beyond any GHG reductions or GHG removal enhancements that would result from compliance with any court order or other legally binding mandates, including management plans (such as Timber Harvest Plans) that are required for government agency approval of harvest activities. Legally binding mandates also include conservation easements or deed restrictions, except where such conservation easements have been enacted in support of the Forest Project, as described in Section 3.5. This requirement is assessed through the Legal Requirement Test in 3.1.1.
2. Forest Projects must achieve GHG reductions or GHG removal enhancements above and beyond any GHG reductions or GHG removal enhancements that would result from engaging in Business-As-Usual activities, as defined by the Regulation and the requirements described and assessed through the Performance Test in Section 3.1.2.

3.1.1 Legal Requirement Test

To meet additionality requirements, the following legal requirement test must be met, specific to each type of Forest Project.

3.1.1.1 Reforestation Projects

Reforestation Project activities cannot be legally required (as defined in 3.1 above) at the time of offset project commencement. Modeling of the Forest Project's baseline carbon stocks must reflect all legal constraints, as required in Section 6.1 of this protocol.

3.1.1.2 Improved Forest Management Projects

Improved Forest Management Project activities (defined as management activities intended to maintain or increase carbon stocks relative to baseline levels) cannot be legally required (as defined in 3.1 above) at the time of offset project commencement. Modeling of the Forest Project's baseline carbon stocks must reflect all legal constraints, as required in Section 6.2 of this protocol.

3.1.1.3 Avoided Conversion Projects

Avoided Conversion Project activities cannot be legally required (as defined in 3.1 above) at the time of offset project commencement. Modeling of the Forest Project's baseline carbon stocks must reflect all legal constraints, as required in Section 6.3 of this protocol.

Official documentation must be submitted demonstrating that the type of anticipated land use conversion is legally permissible. Such documentation must fall into at least one of the following categories:

1. Documentation indicating that the current land use policies, including zoning and general plan ordinances, and other local and state statutes and regulations, permit the anticipated type of conversion.
2. Documentation indicating that the Forest Owner(s) obtained all necessary approvals from the governing county to convert the Project Area to the proposed type of non-forest land use (including, for instance, certificates of compliance, subdivision approvals, timber conversion permits, other rezoning, major or minor use permits, etc.).
3. Documentation indicating that similarly situated forestlands within the project's Assessment Area were recently able to obtain all necessary approvals from the governing county, state, or other governing agency to convert to a non-forest land use (including, for instance, certificates of compliance, subdivision approvals, timber conversion permits, other rezoning, major or minor use permits, etc.).

3.1.2 Performance Test

The Performance Test is satisfied if the following requirements are met, depending on the type of Forest Project.

3.1.2.1 Reforestation Projects

A Reforestation Project that occurs on land that has had less than 10 percent tree canopy cover for at least 10 years automatically satisfies the Performance Test.

A Reforestation Project that occurs on land that has undergone a Significant Disturbance satisfies the Performance Test if:

1. The Forest Project corresponds to a scenario in Appendix E, Table E.1, indicating that it is "eligible" (as determined by the requirements and methods in Appendix E); or
2. The Forest Project occurs on a type of land for which the Forest Owner has not historically engaged in or allowed timber harvesting. (Examples of such land include municipal or state parks.)

3.1.2.2 Improved Forest Management Projects

An Improved Forest Management Project automatically satisfies the Performance Test. Project activities are considered additional to the extent they produce GHG reductions and/or GHG removal enhancements in excess of those that would have occurred under a conservative Business-As-Usual Scenario, as defined by the baseline estimation requirements in Section 6.2.1.

3.1.2.3 Avoided Conversion Projects

An Avoided Conversion Project satisfies the Performance Test if a real estate appraisal for the Project Area (as defined in Section 4) is submitted indicating the following:

1. *The Project Area is suitable for conversion.* The appraisal must clearly identify the highest value alternative land use for the Project Area and indicate how the physical characteristics of the Project Area are suitable for the alternative land use.
    a. At a minimum, where conversion to commercial, residential, or agricultural land uses is anticipated, the appraisal must indicate that the slope of Project Area land does not exceed 40 percent.

b. Where conversion to agricultural land use is anticipated, the appraisal must provide:
    i. Evidence of soil suitability for the type of expected agricultural land use.
    ii. Evidence of water availability for the type of expected agricultural land use.
c. Where conversion to mining land use is anticipated, the appraisal must provide evidence of the extent and amount of mineral resources existing in the Project Area, and the commercial viability of mineral extraction.
d. The appraisal must identify specific portions of the Project Area suitable for the identified alternative land use. For example, an appraisal that identified a golf course as an alternative land use must specify the approximate acres suitable for fairways, greens, clubhouses, and outbuildings.

2. *The alternative land use for the Project Area has a higher market value than forestland.* The appraisal for the property must demonstrate that the fair market value of the anticipated alternative land use for the Project Area is at least 40 percent greater than the value of the current forested land use.

Where conversion to residential, commercial, or recreational land uses is anticipated, the appraisal must also describe the following information:

1. The proximity of the Project Area to metropolitan areas.
2. The proximity of the Project Area to grocery and fuel services and accessibility of those services.
3. Population growth within 180 miles of the Project Area.

The appraisal must be conducted in accordance with the Uniform Standards of Professional Appraisal Practice[3] and the appraiser must meet the qualification standards outlined in Internal Revenue Code, Section 170 (f)(11)(E)(ii).[4]

3.2 Offset Project Commencement

The date of offset project commencement for a Forest Project is the date on which an activity is first implemented that will lead to increased GHG reductions or GHG removal enhancements relative to the Forest Project's baseline. The following actions identify offset project commencement for each project type:

- For a Reforestation Project, the action is the planting of trees, the removal of impediments to natural regeneration, or site preparation for the planting of trees, whichever comes first.
- For an Improved Forest Management Project, the action is initiating forest management activities that increase sequestration and/or decrease emissions relative to the baseline, or transferring the Project Area to public ownership.
- For an Avoided Conversion Project, the action is committing the Project Area to continued forest management and protection through recording a conservation

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[3] Uniform Standards of Professional Appraisal Practice. http://www.uspap.org/2010USPAP/toc.htm. (Accessed October 1, 2010).

[4] Section 170 (f)(11)(E)(ii) of the Internal Revenue Code defines a qualified appraiser as "an individual who -
(I) has earned an appraisal designation from a recognized professional appraiser organization or has otherwise met minimum education and experience requirements set forth in regulations prescribed by the Secretary,
(II) regularly performs appraisals for which the individual receives compensation, and
(III) meets such other requirements as may be prescribed by the Secretary in regulations or other guidance."

easement with a provision to maintain the Project Area in forest cover or transferring the Project Area to public ownership.

An Improved Forest Management project's offset project commencement date must be linked to a discrete, verifiable action that delineates a change in practice relative to the Forest Project's baseline. Any one of the following actions denotes an Improved Forest Management project's offset project commencement date:

- Recordation of a conservation easement on the Project Area. The date the easement was recorded is the Forest Project's offset project commencement date.
- Transferring of property ownership (to a public or private entity). The offset project commencement date is the date of property transfer.
- Submitting the offset project listing information specified in Section 9.1.1. Offset project commencement is the date of submittal of listing information, provided that the offset project completes verification within 30 months of being submitted. If the offset project does not meet this deadline, the listing information must be resubmitted under the latest version of the protocol.

Adequate documentation denoting the offset project commencement date must include where applicable, deeds of trust, title reports, conservation easement documentation, dated forest management plans, and/or other relevant contracts or agreements.

3.3 Project Crediting Period

The crediting period for offset projects using this protocol is 25 years. This means that after a successful initial verification, a Forest Project will be eligible to receive Offset Credits for GHG reductions and/or removals quantified using this protocol, and verified by ARB-approved verification bodies, for a period of 25 years following the offset project's commencement date. A project may be renewed for subsequent crediting periods, subject to approval at that time and use of the quantification methods in the most recent approved version of the Forest Offset Protocol at the time of renewal.

The baseline for any Forest Project under this version of the Forest Offset Protocol is valid for the duration of the Project Life following a successful initial verification where the offset project receives a Positive Verification Statement.

3.4 Project Life and Minimum Time Commitment

Project Life is defined as the period of time between offset project commencement and a period of 100 years following the issuance of any ARB or registry offset credit for GHG reductions or GHG removal enhancements achieved by the offset project. Forest Projects must continue to monitor, verify and report offset project data for a period of 100 years following any ARB or registry offset credit issuance. For example, if ARB or registry offset credits are issued to a Forest Project in year 25 following offset project commencement, monitoring and verification activities must be maintained until year 125.

There are three possible exceptions to this minimum time commitment:

1. A Forest Project automatically terminates if a Significant Disturbance occurs leading to an Unintentional Reversal that reduces the Forest Project's Standing Live Carbon Stocks below the Forest Project's baseline Standing Live Carbon Stocks. If this occurs, the requirements of section 95983(d) of the Regulation shall apply.

2. A Forest Project automatically terminates if Project Lands or timber rights are sold to an entity that does not elect to take over the Forest Project responsibilities and commitments. Such a termination will require a quantity of ARB Offset Credits to be retired, as specified under 'Retiring Compliance Instruments Following Project Termination,' below.
3. A Forest Project may be voluntarily terminated prior to the end of its minimum time commitment if the required quantities of Compliance Instruments are retired, as specified under 'Retiring Compliance Instruments Following Project Termination,' below.

Retiring Compliance Instruments Following Project Termination

If a Forest Project is terminated for any reason except an unintentional reversal, the Forest Owner must replace any ARB Offset Credits that have previously been issued based on the requirements in the Regulation and the following provisions:

a. For a Reforestation or Avoided Conversion Project, a quantity of Compliance Instruments equal to the total number of ARB Offset Credits issued, and where applicable, all Early Action Offset Credits issued pursuant to section 95990(i) of the Regulation, to the project over the preceding 100 years must be retired.
b. For an Improved Forest Management Project, a quantity of Compliance Instruments equal to the total number of ARB Offset Credits issued, and where applicable, all Early Action Offset Credits issued pursuant to section 95990(i) of the Regulation, to the project over the preceding 100 years, multiplied by the appropriate compensation rate indicated in Table 3.1 must be retired.

Table 3.1. Compensation Rate for Terminated Improved Forest Management Projects

Number of years that have elapsed between offset project commencement and the date of termination	Compensation Rate
0-5	1.40
6-10	1.20
11-20	1.15
21-25	1.10
31-50	1.05
>50	1.00

3.5 Use of Qualified Conservation Easements

For Avoided Conversion Projects on private land, the Forest Owner must record a Qualified Conservation Easement against the offset project's property in order for the Forest Project to be eligible. Any Forest Project that records a Qualified Conservation Easement may reduce its risk rating and required contribution to the Forest Buffer Account in Appendix D. To be "qualified" for purposes of ARB's compliance offset program, the conservation easement must:

a. Be granted by the owner of the fee to a qualified holder of a conservation easement in accordance with the conservation easement enabling statute of the state in which the project is located;
b. Be perpetual in duration;

c. Expressly acknowledge that ARB is a third party beneficiary of the conservation easement with the right to enforce all obligations under the easement and all other rights and remedies conveyed to the holder of the easement. These rights include standing as an interested party in any proceeding affecting the easement.

Qualified Conservation Easements must be recorded no earlier than one year before the offset project's commencement date. If a Qualified Conservation Easement was recorded more than one year prior to the offset project commencement date, the limits imposed by the easement on forest management activities must be considered a legal mandate for the purpose of satisfying the legal requirement test for additionality (Section 3.1.1) and in determining the Forest Project's baseline (Section 0).

As indicated in Section 3.2, an offset project commencement date must be linked to a discrete, verifiable action. The recordation of a conservation easement may be used to denote the commencement date of pre-existing projects between December 31, 2006 and December 31, 2010. Any previously recorded conservation easement may only be considered a Qualified Conservation Easement if it was recorded within one year prior to the identified project commencement date. Any previously recorded conservation easement must still meet, or be modified to meet, all of the requirements of this section (i.e. expressly acknowledging ARB as a third-party beneficiary) in order to be considered "qualified."

The conservation easement may be amended to exclude ARB as a third party beneficiary upon termination of the Forest Project or once all legal requirements for monitoring and verification of carbon stocks under this Compliance Offset Protocol have been met.

3.6 Project Location

All Forest Projects must be located in the United States of America. Reforestation Projects and Improved Forest Management Projects may be located on private land, or on state or municipal public land. Avoided Conversion Projects must be implemented on private land, unless the land is transferred to public ownership as part of the project.

All Forest Projects on public lands must be approved by the government agency or agencies responsible for management activities on the land. This approval must include an explicit approval of the Forest Project's baseline, as determined in Section 0, and must involve any public vetting processes necessary to evaluate management and policy decisions concerning the project activity. Offset projects on federal lands that are not included in the categories of land in the following paragraph are not eligible at this time.

Forest 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) in 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.

The Forest Offset Protocol contains data tables, equations, and benchmark data applicable to projects located in the United States. The methods required by this protocol for estimating baseline carbon stocks for Forest Projects cannot currently be applied outside the United

States, as they rely on U.S.-specific data sets and models. Forest Projects in Alaska and Hawaii are not eligible at this time due to lack of region-specific data.

3.7 Regulatory Compliance

As stated in the Regulation, Project Lands must fulfill all applicable local, regional and national requirements on environment impact assessments that apply based on the offset project location. Offset projects must also meet any other local, regional, and national requirements that might apply.

Each time the Forest Project is verified, the Offset Project Operator or Authorized Project Designee must attest that the Forest Owner and Project Lands are in compliance with all applicable laws and regulations. The Offset Project Operator or Authorized Project Designee are required to disclose in writing to the verifier any and all instances of non-compliance associated with the Project Lands with any legal requirement. If a verifier finds that an offset project is in a state of non-compliance with any environmental law or regulation, then ARB or registry offset credits will not be issued for GHG reductions or GHG removal enhancements that occurred during any reporting period of non-compliance.

3.8 Sustainable Harvesting and Natural Forest Management Practices

Forest Projects can create long-term climate benefits as well as provide other environmental benefits, including the sustaining of natural ecosystem processes. This protocol requires eligible offset projects to employ both sustainable long-term harvesting practices and Natural Forest Management practices over time, as described below. Any non-conformance with the sustainable harvesting and Natural Forest Management requirements in this section will result in an adverse offset verification statement during the reporting periods that the Forest Project was out of conformance.

3.8.1 Sustainable Harvesting Practices

At the time commercial harvesting is either planned or initiated within the Project Area, the Offset Project Operator or Authorized Project Designee must demonstrate that the Forest Owner(s) employs and demonstrates sustainable long-term harvesting practices on all of its forest landholdings, including the Project Area, using one of the following options:

1. The Forest Owner must be certified under the Forest Stewardship Council, Sustainable Forestry Initiative, or Tree Farm System certification programs. Regardless of the program, the terms of certification must require adherence to and verification of harvest levels which can be permanently sustained over time.
2. The Forest Owner must adhere to a renewable long-term management plan that demonstrates harvest levels which can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency.
3. The Forest Owner must employ uneven-aged silvicultural practices (if harvesting occurs) and must maintain canopy cover averaging at least 40 percent across the entire forestland owned by the Forest Owner in the same Assessment Areas covered by the Project Area, as measured on any 20 acres within the Forest Owner's landholdings found in any of these Assessment Areas, including land within and outside of the Project Area (areas impacted by Significant Disturbance may be excluded from this test).

Forest Owners who acquire new forest landholdings within their entity have up to 5 years to incorporate such acquisitions under their certification or management plan, whether or not such land is contiguous with the Project Area.

3.8.2 Natural Forest Management

All Forest Projects must promote and maintain a diversity of native species and utilize management practices that promote and maintain native forests comprised of multiple ages and mixed native species within the Project Area and at multiple landscape scales ("Natural Forest Management").

All Forest Projects are required to establish and/or maintain forest types that are native to the Project Area. For the purposes of this protocol, native forests are defined as those forests occurring naturally in an area, as neither a direct nor indirect consequence of human activity post-dating European settlement.

The Forest Offset Protocol Resources section of ARB's webpage provides required references by Assessment Area for the definition of native forests (see Appendix F). If a state/regional reference is unavailable or inadequate, documentation from a state botanist or other qualified independent resource, recognized as expert by academic, private and government organizations, must be submitted indicating that the project promotes and maintains native forests per the definition above. Where supported by scientific peer-reviewed research, the planting of native species outside of their current distribution is allowed as an adaptation strategy due to climate change. Such planting must be done in accordance with a state or federally approved adaptation plan, or a local plan that has gone through a transparent public review process. A written statement must be submitted from the government agency in charge of forestry regulation in the state where the project is located stipulating that the planting of native trees outside their current range is appropriate as an adaptation to climate change.

The following requirements shall apply to all Forest Projects regardless of the silvicultural or regeneration methods that are used to manage or maintain the forest:

1. Forest Projects must maintain or increase standing live carbon stocks over the project life, as described in Section 3.8.3.
2. Forest Projects must show verified progress (verified at scheduled site-visits) towards native tree species composition and distribution consistent with the forest type and forest soils native to the Assessment Area.
3. Forest Projects must manage the distribution of habitat/age classes and structural elements to support functional habitat for locally native plant and wildlife species naturally occurring in the Project Area, as specified in Table 3.2 and Section 3.8.4 below.

Forest Projects that initially engage in Natural Forest Management must continue to do so for as long as monitoring and verification of the Forest Project are required by this protocol (i.e. for the duration of the Project Life). Forest Projects that do not initially meet Natural Forest Management criteria but can demonstrate progress towards meeting these criteria at the times identified in Table 3.2 are still eligible.

The evaluation criteria provided in Table 3.2 shall be used to determine if the Forest Project meets the criteria for engaging in Natural Forest Management. The following evaluation must be completed and verified at a Forest Project's first verification and at all subsequent verifications. Forest Project carbon stock inventories (requirements for which are contained in Appendix A) should be used as the basis of these assessments where applicable.

Table 3.2. Evaluation criteria to test if a Forest Project meets the requirement for the establishment and maintenance of native species and natural forest management

Criteria	When Assessed	Results of not passing criteria	Application Rules
Native Species			
Project consists of at least 95% native species based on the sum of carbon in the standing live carbon pool. The assessment shall be conducted using estimates of stems per acre for Reforestation Projects and basal area per acre for Improved Forest Management and Avoided Conversion Projects.	Assessed at initial verification from inventory data.	Forest Project is not eligible unless demonstrated that management will achieve this goal over the project life.	Applies to all project types throughout the project life
	Assessment during verification site visits must demonstrate continuous progress toward goal. This criterion must be met within 25 years.	Project is not in conformance with protocol requirements.	
Composition of Native Species			
Improved Forest Management and Avoided Conversion Projects Where the Project Area naturally consists of a mixed species distribution, no single species' prevalence, measured as the percent of the basal area of all live trees in the Project Area, exceeds the percentage value of standing live carbon shown under the heading 'Species Diversity Index' in the Forest Offset Protocol Resources section of ARB's website. Where the Project Area does not naturally consist of a mixed species distribution, a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that the project area does not naturally consist of a mixed species distribution must be submitted. **Reforestation** To the extent seed is available, and/or physical site characteristics permit, Reforestation Projects that involve planting of seedlings must plant a mixture of species such that no single species' prevalence, measured as the percent of all live tree stems in the Project Area, exceeds the percentage value shown under the heading 'Species Diversity Index' in the Assessment Area table in the Forest Offset Protocol Resources section of ARB's website. Where seed is unavailable, the Reforestation Project is based on natural regeneration, or physical site characteristics are limiting, a written statement from the government agency in charge of forestry regulation in the state where the project is located stipulating that seed is unavailable, the Reforestation Project is based on natural regeneration, or physical site characteristics are limiting must be submitted.	Species composition is assessed at project initiation from inventory data.	Project is not eligible, unless it is demonstrated that management activities will enable this goal to be achieved over the project life.	Applies to all project types throughout the project life Some project sites may not be capable of meeting the requirement. In these cases, a written statement from the government agency in charge of forestry regulation in the state where the project is located must be submitted as described under "Criteria"
	Species composition is assessed at initial verification from inventory data. Project must show continuous progress toward criteria. These criteria must be met within 25 years.	Project is not in conformance with protocol requirements.	
Distribution of Age Classes/Sustainable Management			
All forest landholdings owned or controlled by the Forest Owner are currently under one of the following: 1. Third party certification under the Forest Stewardship Council, Sustainable Forestry Initiative, or Tree Farm System, whose certification standards require adherence to and verification of harvest levels which can be permanently sustained over time, or	Condition shall be met at all times during project and is assessed during each verification.	Project is not in conformance with protocol requirements.	Applies to all project types at first regeneration harvest

2. Operating under a renewable long-term management plan that demonstrates harvest levels which can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency, or 3. The Forest Owner must employ uneven-aged silvicultural practices and canopy retention averaging at least 40 percent across the forest, as measured on any 20 acres within the entire forestland owned by the Forest Owner, including land within and outside of the Project Area. (Areas impacted by Significant Disturbance may be excluded from this test.)			
On a watershed scale up to 10,000 acres (or the project area, whichever is smaller), all projects must maintain, or make progress toward maintaining, no more than 40 percent of their forested acres in ages less than 20 years. (Areas impacted by Significant Disturbance may be excluded from this test.)	Age classes (if even age management is used) are assessed at project initiation and each verification site visit.	NA	
	Project must show continuous progress toward criteria. This criterion must be met within 25 years.	Project is not in conformance with protocol requirements.	
Structural Elements (Standing and Lying Dead Wood)			
Lying dead wood must be retained in sufficient quantities, as described below. **For portions of the Project Area that have not recently undergone salvage harvesting:** If a verifier determines that the quantity of lying dead wood is commensurate with recruitment from standing dead trees (i.e. there is no evidence that lying dead wood has been actively removed), the project must maintain (or demonstrate ongoing progress toward) an average of at least: ▪ one (1) metric ton of carbon (C) per acre; or ▪ 1% of standing live carbon stocks, in *standing* dead wood, whichever is higher, If a verifier determines that the quantity of lying dead wood is **not** commensurate with recruitment from standing dead trees (i.e. it appears lying dead wood has been actively removed), the project must maintain (or demonstrate ongoing progress toward) an average of at least: ▪ two (2) metric tons of carbon (C) per acre; or ▪ 1% of standing live carbon stocks, in *standing* dead wood, whichever is higher, Standing dead wood may be evenly or unevenly distributed throughout the portion of the Project Area unaffected by salvage harvesting, as long as the appropriate minimum average tonnage per acre requirement is met. **For portions of the Project Area that have undergone salvage harvesting within the previous year:** If a verifier determines that the quantity of lying dead wood following salvage harvest is commensurate with recruitment from standing dead trees, the project must maintain (or demonstrate ongoing progress toward) an average of at least	Assessed during project at each verification audit.	Project is not in conformance with protocol requirements.	Applies to all project types throughout the project life

two (2) metric tons of carbon (C) per acre in *standing* dead wood, If a verifier determines that the quantity of lying dead wood following harvest is **not** commensurate with recruitment from standing dead trees, the project must maintain (or demonstrate ongoing progress toward) an average of at least four (4) metric tons of carbon (C) per acre in *standing* dead wood, Standing dead wood may be evenly or unevenly distributed throughout the portion of the Project Area subject to salvage harvesting, as long as the appropriate minimum average tonnage per acre requirement is met. This requirement must be met for a period of 30 years following the salvage harvest. After 30 years, the portion of the Project Area subject to salvage harvesting must meet the requirements for portions that have not recently undergone salvage harvesting (described above).			

3.8.3 Promotion of the Onsite Standing Live Carbon Stocks

In an effort to promote and maintain the environmental benefits of Forest Projects, the standing live carbon stocks within the Project Area must be maintained and/or increased during the Project Life. Therefore, except as specified below, ARB or registry offset credits will not be issued for quantified GHG reductions and GHG removal enhancements achieved by a Forest Project if a Forest Project's Offset Project Data Reports – over any 10-year consecutive period – indicate a decrease in the standing live carbon stocks.

Exceptions are allowed where reductions in standing live carbon stocks are important for maintaining and enhancing forest health, environmental co-benefits, or the long-term security of all carbon stocks; where reductions are due to non-harvest disturbances; or where reductions are required by law. Note that these exceptions in no way change or affect the requirements related to compensating for reversals, as detailed in Section 7.3.

Forest Projects whose standing live carbon stocks have decreased over a 10-year period are not in conformance with protocol requirements, except if the decrease in standing live carbon stocks is due to one of the following causes:

1. The decrease is demonstrably necessary to substantially improve the Project Area's resistance to wildfire, insect, or disease risks. The actions that will be taken to reduce the risks must be documented. The techniques used to improve resistance must be supported by relevant published peer reviewed research.
2. The decrease is associated with a planned balancing of age classes (regeneration, sub-merchantable, and merchantable) and is detailed in a long-term management plan that demonstrates harvest levels can be permanently sustained over time and that is sanctioned and monitored by a state or federal agency. In this case, documentation must be submitted at the time of the Forest Project's Listing, indicating that a balancing of age classes, resulting in a decrease in the standing live carbon stocks, is planned at the initiation of the Forest Project (Figure 3.1). At no time over the Project Life shall the Forest Project's inventory of standing live carbon stocks fall below the Forest Project's baseline standing live carbon stocks, or 20 percent less than the Forest Project's standing live carbon stocks at the project's initiation, whichever is higher. Over any

consecutive 10-year period, average standing live carbon stocks must be maintained at or above the standing live carbon stocks at the initiation of the project.

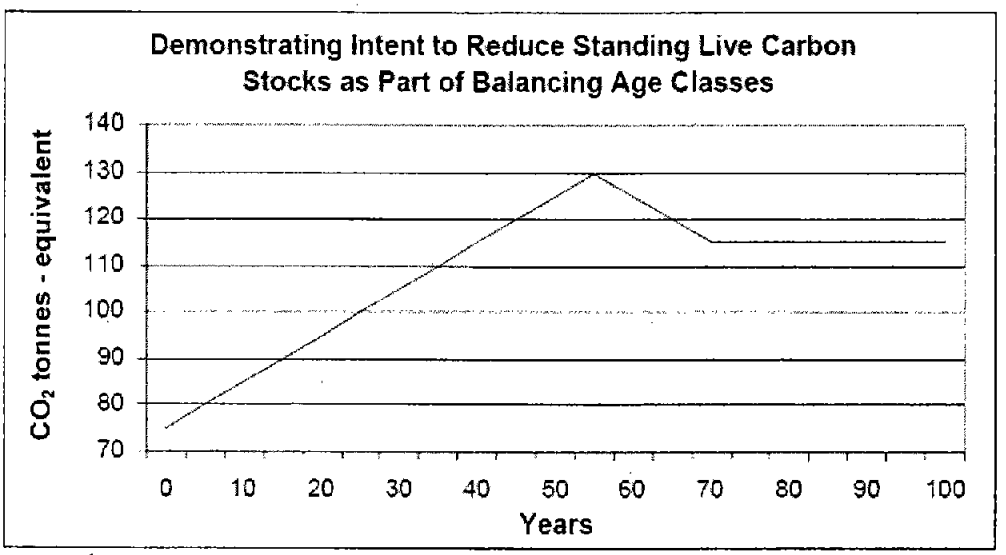


Figure 3.1. Example of Reducing Standing Live Carbon Stocks as Part of Balancing Age Classes

3. The decrease is part of normal silviculture cycles for forest ownerships less than 1,000 acres. Inventory fluctuations are a normal part of silvicultural activities. Periodic harvest may remove more biomass than the biomass growth over the past several years. At no time during the Project Life shall the Forest Project's inventory of standing live carbon stocks fall below the Forest Project's baseline standing live carbon stocks, or 20 percent less than the Forest Project's standing live carbon stocks at the project's initiation, whichever is higher. Over any consecutive 10-year period, average standing live carbon stocks must be maintained at or above the standing live carbon stocks at the initiation of the project. Documentation submitted at the time the Forest Project is Listed must indicate that fluctuations in the Forest Project's standing live carbon stocks are an anticipated silvicultural activity and that the overall trend will be for standing live carbon stocks to increase or stay the same over the life of the offset project (Figure 3.2).

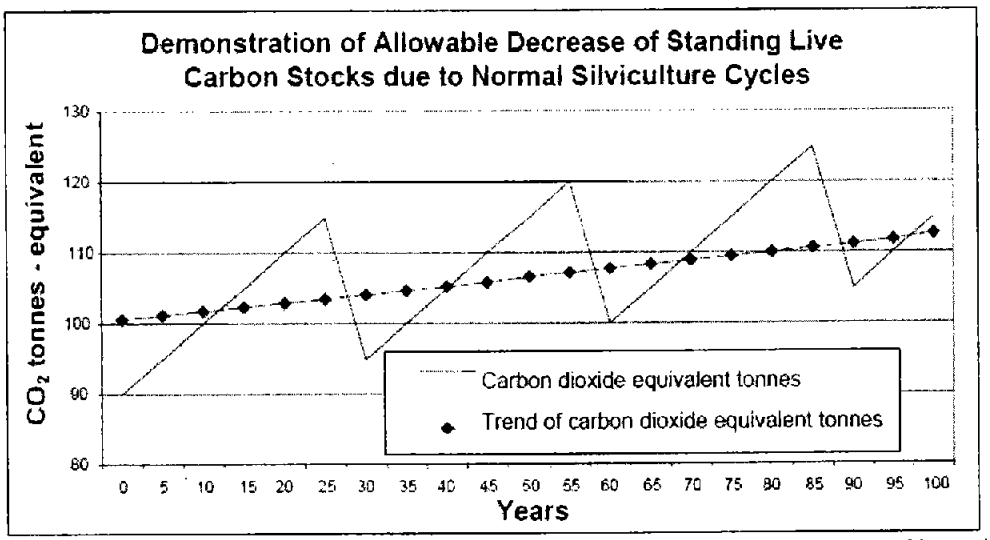


Figure 3.2. Example of Allowable Decrease of Standing Live Carbon Stocks due to Normal Silviculture Cycles

4. The decrease is due to an unintentional reversal such as wildfire, disease, flooding, wind-throw, insect infestation, or landslides.
5. The decrease in standing live carbon stocks occurs after the final crediting period (during the required 100 year monitoring period) as long as the residual live carbon stocks are maintained at a level that assures all credited standing live carbon stocks are permanently maintained.

3.8.4 Balancing Age and Habitat Classes

A variety of silvicultural practices may be employed in the Project Area during the course of a Forest Project though the protocol does not endorse any particular practice. To ensure environmental integrity, Forest Projects must meet a minimum set of standards in the use of any such practices.

For offset projects that employ even-aged management practices, harvesting must be limited to stands no greater than 40 acres. Stands adjacent to recently harvested stands must not be harvested using an even-aged harvest until the average age of the adjacent stand is at least 5-years old, or the average height in the adjacent stand is at least 5 feet. On a watershed scale up to 10,000 acres, all projects must maintain, or make progress toward maintaining, no more than 40 percent of their forested acres in ages less than 20 years. Areas impacted by a Significant Disturbance are exempt from this test until 20 years after reforestation of such areas.

The protocol does not override a landowner's obligation to abide by applicable laws and regulations, including any governing forest practice rules that may be more stringent. Regardless of the silvicultural practice employed, landowners must fulfill their commitment under the protocol to permanently maintain or increase onsite standing live carbon stocks (i.e. the carbon in live trees within the Project Area) as specified in Section 3.8.3.

4 Identifying the Project Area

The geographic boundaries defining the Project Area must be described in detail at the time a Forest Project is Listed. The boundaries must be defined using a map, or maps, that display public and private roads, major watercourses (4th order or greater), topography, towns, and either public land survey townships, ranges, and sections or latitude and longitude. The maps must be of adequate resolution to clearly identify the required features. The Project Area can be contiguous or separated into tracts. The Project Area may also extend across multiple Assessment Areas within an Ecosection or Supersection (see Appendix F) and across no more than two adjacent Ecosections or Supersections.

For Improved Forest Management Projects, the geographic boundaries may be defined such that non-forested areas, or areas not under forest management, are excluded from the Project Area.

For Reforestation Projects, the Project Area must be on land that has had less than 10 percent tree canopy cover for a minimum of ten years, or that have been subject to a Significant Disturbance that resulted in at least 20 percent of the carbon stocks being emitted. A Reforestation Project may defer finalizing the boundaries of the Project Area until the second full verification provided: (1) all lands included in the Project Area were initially included in the Project Area during listing, and (2) the Reforestation Project has elected to defer its initial inventory until the second full verification. This allows Reforestation Projects to initially identify a larger Project Area during project listing that may be revised prior to the completion of the forest inventory and the issuance of any ARB or registry offset credits.

For Avoided Conversion Projects, the Project Area is defined through the required appraisal process. The Project Area must be determined following the boundary definitions in Table 4.1 based on the type of anticipated conversion. All lands in the Project Area must be covered by the Qualified Conservation Easement or transferred to public ownership as part of the program.

Table 4.1. Project Area Definition for Avoided Conversion Projects

Conversion Type	Project Area Definition
Residential	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in residential development.
Agricultural Conversion or Mining	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in agricultural production or mining.
Golf Course	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' as a golf course. This is to include forested areas within 200' of fairways, greens, and buildings.
Commercial Buildings	The boundary of the parcel or parcels that have been appraised as having a 'higher and better use' in commercial buildings. This is to include forested areas with 200' of suitable building sites.

5 Offset Project Boundary

The Offset Project Boundary defines all the GHG emission sources, GHG sinks, and GHG reservoirs (SSR's) that must be accounted for in quantifying a Forest Project's GHG reductions and GHG removal enhancements (Section 0). The Offset Project Boundary encompasses all the GHG emission SSR's that may be significantly affected by Forest Project activities, such as forest carbon stocks and harvested wood products. For accounting purposes, the GHG sources, GHG sinks, and GHG reservoirs included in the Offset Project Boundary are organized according to whether they are predominantly associated with a Forest Project's "Primary Effect" (i.e. the Forest Project's intended changes in carbon stocks, GHG emissions, or GHG removal enhancements) or its "Secondary Effects" (i.e. unintended changes in carbon stocks, GHG emissions, or GHG removal enhancements caused by the Forest Project). Secondary effects may include increases in mobile combustion CO_2 emissions associated with site preparation, as well as increased CO_2 emissions caused by the shifting of harvesting activities from the Project Area to other forestlands (referred to as "Leakage"). Offset projects are required to account for Secondary Effects following the methods described in Section 0.

The following tables provide a comprehensive list of the SSRs that may be affected by a Forest Project, and indicate which SSRs must be included in the Offset Project Boundary for each type of Forest Project. If a SSR is designated as a "reservoir/pool," this means that GHG reductions and GHG removal enhancements are accounted for by quantifying changes in carbon stock levels. For SSRs designated as GHG sources or GHG sinks, GHG reductions and GHG removal enhancements are accounted for by quantifying changes in GHG emission or GHG removal enhancement rates, as described in the tables.

5.1 Reforestation Projects

Table 5.1. Offset Project Boundary – Reforestation Projects

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
Primary Effect Sources, Sinks, and Reservoirs					
RF-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by field measurements and updating forest carbon inventory
RF-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
RF-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
RF-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
RF-5	Litter and duff carbon (carbon in	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
	dead plant material)				**Project:** N/A
RF-6	Soil carbon	Reservoir / Pool	CO_2	*Included/excluded: Soil carbon must be included in the Offset Project Boundary if any of the following occur: • Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds (or is expected to exceed from the baseline characterization and modeling) 25 percent of the Project Area over the Project Life, or • Mechanical site preparation activities are not conducted on contours.	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
RF-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Included	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
RF-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded when project harvesting exceeds baseline Included when project harvesting is below baseline	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
Secondary Effect Sources, Sinks, and Reservoirs					
RF-9	Biological emissions from site preparation activities	Source	CO_2	*Included: Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSRs #RF-2 and #RF-6)
RF-10	Mobile combustion emissions from site preparation activities	Source	CO_2	Included	**Baseline:** N/A **Project:** Estimated using default emission factors
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-11	Mobile combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-12	Stationary combustion emissions from	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
	ongoing project operation & maintenance		CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	Included	**Baseline:** N/A **Project:** Estimated using default land-use conversion factors for non-project land
RF-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
RF-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
RF-17	Biological emissions from decomposition of forest products	Source	CO_2	Included	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #RF-7) and landfills (SSR #RF-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #RF-7) and landfills (SSR #RF-8)
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A

5.2 Improved Forest Management Projects

Table 5.2. Offset Project Boundary – Improved Forest Management Projects

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
Primary Effect Sources, Sinks, and Reservoirs					
IFM-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by field measurements and updating forest carbon inventory
IFM-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
IFM-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
IFM-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
IFM-5	Litter and duff carbon (carbon in dead plant material)	Reservoir / Pool	CO_2	Excluded	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
IFM-6	Soil carbon	Reservoir / Pool	CO_2	*Included/ Excluded Soil carbon must be included in the Offset Project Boundary, if any of the following activities occur: ▪ Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds (or is expected to exceed from the baseline characterization and modeling) 25 percent of the Project Area over the Project Life, or ▪ Mechanical site preparation activities are not conducted on contours.	**Baseline:** Modeled based on initial field inventory measurements **Project:** Measured by updating forest carbon inventory
IFM-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Included	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
IFM-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded when project harvesting exceeds baseline Included when project harvesting is below baseline	**Baseline:** Eslimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
Secondary Effect Sources, Sinks, and Reservoirs					
IFM-9	Biological	Source	CO_2	*Included	**Baseline:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
	emissions from site preparation activities			Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs	**Project:** Quantified based on measured carbon stock changes in included reservoirs (SSR #IFM-6, where applicable)
IFM-10	Mobile combustion emissions from site preparation activities	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-11	Mobile combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-12	Stationary combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
IFM-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	Included / Excluded	**Baseline:** N/A **Project:** Estimated using a default 20% "leakage" factor applied to the difference in harvest volume relative to baseline
IFM-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
IFM-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
IFM-17	Biological emissions from decomposition of forest products	Source	CO_2	*Included	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #IFM-7) and landfills (SSR #IFM-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #IFM-7) and landfills (SSR #IFM-8)
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A

5.3 Avoided Conversion Projects

Table 5.3. Offset Project Boundary – Avoided Conversion Projects

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
Primary Effect Sources, Sinks, and Reservoirs					
AC-1	Standing live carbon (carbon in all portions of living trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements and expected land-use conversion rates **Project:** Measured by field measurements and updating forest carbon inventory
AC-2	Shrubs and herbaceous understory carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-3	Standing dead carbon (carbon in all portions of dead, standing trees)	Reservoir / Pool	CO_2	Included	**Baseline:** Modeled based on initial field inventory measurements and expected land-use conversion rates **Project:** Measured by updating forest carbon inventory
AC-4	Lying dead wood carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-5	Litter and duff carbon (carbon	Reservoir / Pool	CO_2	Excluded	**Baseline:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
	in dead plant material)				**Project:** N/A
AC-6	Soil carbon	Reservoir / Pool	CO_2	*Included/ Excluded Soil carbon must be included in the Offset Project Boundary, if any of the following activities occur: ▪ Site preparation activities involve deep ripping, furrowing, or plowing where soil disturbance exceeds (or is expected to exceed from the baseline characterization and modeling) 25 percent of the Project Area over the Project Life, or Mechanical site preparation activities are not conducted on contours.	**Baseline:** Modeled based on initial field inventory measurements and expected land-use conversion rates **Project:** Measured by updating forest carbon inventory
AC-7	Carbon in in-use forest products	Reservoir / Pool	CO_2	Included	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
AC-8	Forest product carbon in landfills	Reservoir / Pool	CO_2	Excluded when project harvesting exceeds baseline Included when project harvesting is below baseline	**Baseline:** Estimated from modeled harvesting volumes **Project:** Estimated from measured harvesting volumes
Secondary Effect Sources, Sinks, and Reservoirs					
AC-9	Biological emissions from site preparation activities	Source	CO_2	*Included Biological emissions from site preparation are not quantified separately, but rather are captured by measuring changes in included carbon reservoirs	**Baseline:** N/A **Project:** Quantified based on measured carbon stock changes in included reservoirs (SSR #AC-6, where applicable)
AC-10	Mobile combustion emissions from site preparation activities	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-11	Mobile combustion emissions from ongoing project operation & maintenance	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-12	Stationary combustion emissions from	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A

SSR	Description	Type	Gas	Included or Excluded?	Quantification Method
	ongoing project operation & maintenance				
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-13	Biological emissions from clearing of forestland outside the Project Area	Source	CO_2	Included	**Baseline:** N/A **Project:** Estimated using default forestland conversion factors
AC-14	Biological emissions/ removals from changes in harvesting on forestland outside the Project Area	Source / Sink	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
AC-15	Combustion emissions from production, transportation, and disposal of forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-16	Combustion emissions from production, transportation, and disposal of alternative materials to forest products	Source	CO_2	Excluded	**Baseline:** N/A **Project:** N/A
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A
AC-17	Biological emissions from decomposition of forest products	Source	CO_2	Included	**Baseline:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #AC-7) and landfills (SSR #AC-8) **Project:** Quantified as a component of calculating carbon stored for 100 years in wood products (SSR #AC-7) and landfills (SSR #AC-8)
			CH_4	Excluded	**Baseline:** N/A **Project:** N/A
			N_2O	Excluded	**Baseline:** N/A **Project:** N/A Decomposition of forest is not expected to be a significant source of N_2O emissions.

6 Quantifying Net GHG Reductions and GHG Removal Enhancements

This section provides requirements and methods for quantifying a Forest Project's net GHG reductions and GHG removal enhancements.

Quantification Methodology:
For each type of Forest Project, quantification proceeds in seven steps:

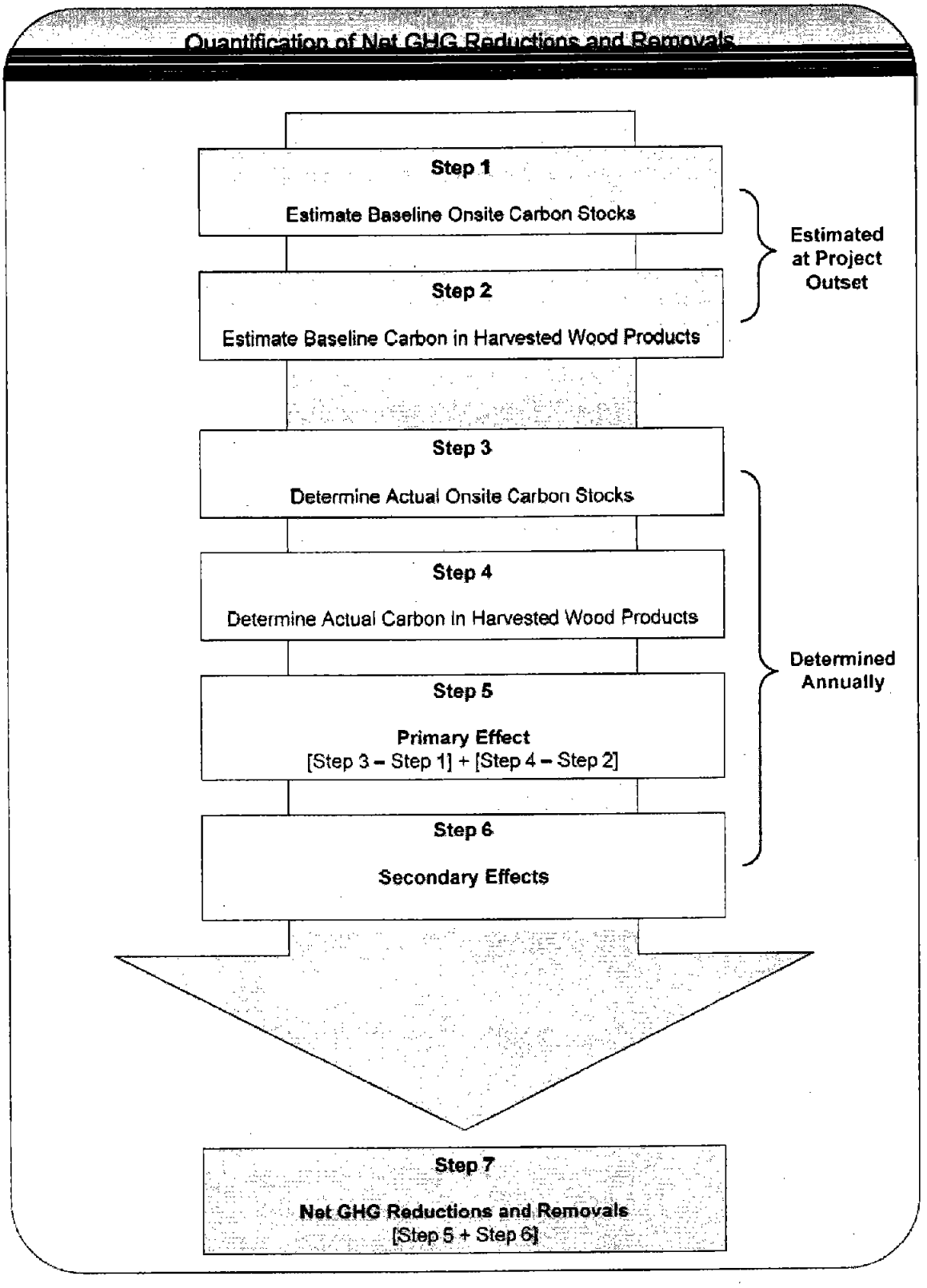
1. **Estimating baseline onsite carbon stocks.** The baseline is an estimate of what would have occurred in the absence of a Forest Project. To establish baseline onsite carbon stocks, the carbon stock changes in each of the Forest Project's required onsite carbon pools (identified in Sections 5.1 to 5.3) must be modeled over 100 years. Modeling must be based on inventoried carbon stocks at the time of the Forest Project's offset project commencement (or when first inventoried as is allowed for Reforestation Projects), following the applicable requirements in this section. Onsite carbon stocks are inventoried following the requirements in Appendix A; modeling of onsite carbon stocks over time must be conducted following the requirements in this section and the requirements and methods in Appendix B. Baseline onsite carbon stocks are estimated over 100 years at the time of the Forest Project's commencement.
2. **Estimating baseline carbon in harvested wood products.** In conjunction with modeling baseline onsite carbon stocks, a forecast of any harvesting that would have occurred in the baseline must be developed and converted to an average annual harvesting volume. From this, the amount of carbon that would have been transferred each year (on average) to long-term storage in wood products can be determined. Baseline harvesting is forecasted following the requirements in this section and carbon stored in wood products must be calculated following the requirements and methods in Appendix C.
3. **Determining actual onsite carbon stocks.** Each year, the Forest Project's actual onsite carbon stocks must be determined. This must be done by updating the Forest Project's forest carbon inventory for the current year, following the requirements and methods in this section and in Appendices A and B. The estimate of actual onsite carbon stocks must be adjusted by an appropriate confidence deduction, as described in Appendix A, Section A.4.
4. **Determining actual carbon in harvested wood products.** Each year, any harvesting in the Project Area must be reported and from this, the amount of carbon transferred to long-term storage in wood products must be calculated following the requirements and methods in Appendix C.
5. **Calculating the offset project's Primary Effect.** Each year, the actual change in GHG emissions or GHG removal enhancements associated with the Forest Project's intended ("Primary") effect must be quantified, as defined in Section 5. For any given year, the Primary Effect is calculated by:
    a. Taking the difference between actual onsite carbon stocks for the current year and actual onsite carbon stocks for the prior year
    b. Subtracting from (a) the difference between baseline onsite carbon stocks for the current year and baseline onsite carbon stocks for the prior year
    c. Adding to (b) the calculated difference between actual and baseline carbon in harvested wood products for the current year (see Equation 6.1.)
6. **Quantifying the offset project's Secondary Effects.** Each year, the actual change in GHG emissions or GHG removal enhancements associated with the Forest Project's unintended ("Secondary") effects must be quantified as defined in Section 5.

Requirements and methods for quantifying Secondary Effects are provided below for each type of Forest Project. Secondary Effects will almost always be negative (i.e. they will reflect an increase in GHG emissions caused by the offset project).

7. **Calculating total net GHG reductions and GHG removal enhancements.** For each year, total net GHG reductions and GHG removal enhancements are calculated by summing a Forest Project's Primary and Secondary Effects. If the result is positive, then the Forest Project has generated GHG reductions and/or GHG removal enhancements in the current year. If the result is negative, this indicates a reversal has occurred except as specified below (see Section 7).

Requirements for how to perform quantification steps 1 to 4 for each Forest Project type are presented in the remainder of this section. The required formula for quantifying annual net GHG reductions and GHG removal enhancements is presented in Equation 6.1. Net GHG reductions and GHG removal enhancements must be quantified and reported in units of carbon dioxide-equivalent (CO_2e) metric tons.

A reversal occurs only if: (1) total net GHG reductions and GHG removal enhancements for the year are negative; and (2) ARB or registry offset credits have previously been issued to the Forest Project. If calculated GHG reductions and GHG removal enhancements are negative and no ARB or registry offset credits have been issued to the project since its commencement date then the result should be treated as a "negative carryover" to GHG reduction calculations in subsequent years (variable N_{y-1} in Equation 6.1). This may happen, for example, because the confidence deduction applied to actual onsite carbon stocks can result in actual values being less than baseline values in a Forest Project's initial years.


Quantification of Net GHG Reductions and Removals
Step 1
Estimate Baseline Onsite Carbon Stocks
Step 2
Estimate Baseline Carbon in Harvested Wood Products
Estimated at Project Outset
Step 3
Determine Actual Onsite Carbon Stocks
Step 4
Determine Actual Carbon in Harvested Wood Products
Step 5
Primary Effect
[Step 3 – Step 1] + [Step 4 – Step 2]
Step 6
Secondary Effects
Determined Annually
Step 7
Net GHG Reductions and Removals
[Step 5 + Step 6]

Quantification Methodology

Equation 6.1.

$$QR_y = [(\Delta AC_{onsite} - \Delta BC_{onsite}) + (AC_{wp,y} - BC_{wp,y}) * 80\% + SE_y] * (1 - ACD) + N_{y-1}$$

Where,

QR_y = Quantified GHG reductions and GHG removal enhancements for year y

ΔAC_{onsite} = $(AC_{onsite,y})(1 - CD_y) - (AC_{onsite,y-1})(1 - CD_{y-1})$

Where,

$AC_{onsite,y}$ = Actual onsite carbon (CO_2e) as inventoried for year y

$AC_{onsite,y-1}$ = Actual onsite carbon (CO_2e) as inventoried for year y-1 (if y is the first year of the offset project, then the value for $AC_{onsite,y-1}$ will be zero)

CD_y = Appropriate confidence deduction for year y, as determined in Appendix A, Section A.4.

CD_{y-1} = Appropriate confidence deduction for year y-1, as determined in Appendix A, Section A.4.

ΔBC_{onsite} = $BC_{onsite,y} - BC_{onsite,y-1}$

Where,

$BC_{onsite,y}$ = Baseline onsite carbon (CO_2e) as estimated for year y

$BC_{onsite,y-1}$ = Baseline onsite carbon (CO_2e) as estimated for year y-1 (if y is the first year of the offset project, then the value for $BC_{onsite,y-1}$ will be zero) [5]

$AC_{wp,y}$ = Actual carbon in wood products produced in year y that is projected to remain stored for at least 100 years (i.e. $WP_{total,y}$ derived for actual harvest volumes following the requirements and methods in Appendix C)

$BC_{wp,y}$ = Averaged annual baseline carbon in wood products that would have remained stored for at least 100 years (i.e. $WP_{total,y}$ derived for baseline harvest volumes following the requirements and methods in Appendix C)

SE_y = Secondary Effect GHG emissions caused by the project activity in year y

ACD = Avoided Conversion Project discount factor, determined in Section 6.3.1

N_{y-1} = Any negative carryover from the prior year (occurs when total quantified GHG reductions are negative prior to the issuance of any CRTs for the project)

Note: The net change in carbon in harvested wood products, $(AC_{wp,y} - BC_{wp,y})$, is multiplied by 80 percent in Equation 6.1 to reflect market responses to changes in wood product production. The general assumption in this protocol is that for every ton of reduced harvesting caused by a

[5] For Improved Forest Management projects, where baseline onsite carbon stocks are averaged across all years, the value for ΔBC_{onsite} will be zero in all years except the first year of the project.

Forest Project, the market will compensate with an increase in harvesting of 0.2 tons on other lands (see Section 6.2.6).

6.1 Reforestation Projects

6.1.1 Estimating Baseline Onsite Carbon Stocks

Quantification Methodology

To estimate baseline carbon stocks for a Reforestation Project:

1. Provide a qualitative characterization of the likely vegetative conditions and activities that would have occurred without the project, taking into consideration any laws, statutes, regulations, or other legal mandates that would encourage or require reforestation on the Project Area. The qualitative assessment shall include an assessment of the commercial value of trees within the Project Area over the next 30 years. The qualitative assessment must be used as the basis for modeling baseline carbon stocks (Step 3).
2. Inventory the carbon stocks in each of the Forest Project's required carbon pools, following the requirements in Appendix A of this protocol.[6] For carbon pools that will be affected by site preparation, the inventory must be conducted prior to any site preparation activities. For those carbon pools that are affected by site preparation, provide an estimate of initial carbon stocks using one of the following alternatives:
    - Measuring carbon stocks using 20 sample plots located in the portion of the Project Area containing the greatest amount of biomass in the pool that will be affected.
    - Stratifying (classifying) the Project Area into similar densities and measuring stocks within the affected carbon pools using 20 sample plots per density class.
    - Measuring the affected carbon stocks based on a grid system across the Project Area.

For other carbon stocks, the inventory may be deferred, as described below.

3. Once a full inventory is obtained, perform a computer simulation that models the carbon stocks for 100 years following the forest project's commencement date, based on the qualitative characterization of what would have occurred without the offset project. The modeling must follow the requirements and methods for modeling contained in Appendix B, Section B.3, incorporating any conditions and constraints specified in the qualitative characterization of the baseline (Step 1, above). The computer simulation must model the expected growth in carbon stocks associated with pre-existing trees in the Project Area (i.e. those not planted as part of the Forest Project).

Deferral of Initial Inventory for Carbon Stocks Not Affected by Site Preparation

The inventory of carbon stocks that are not affected by site preparation may be deferred until a Reforestation Project's second verification. At the time of the second verification, an estimated inventory of the all required carbon stocks at the time of the Forest Project's offset project commencement date must prepared by:

1. Assuming standing dead carbon stocks at the time of the Forest Project's offset project commencement date were equal to the standing dead carbon stocks measured and verified at the second verification.

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[6] Initial carbon stocks could be zero if the Project Area has no quantifiable forest cover or required carbon pools.

2. Using an approved growth model or a stand table projection methodology, as described in Appendix B, Section B.1, to derive an estimate of standing live carbon stocks in pre-existing trees (i.e. those not planted as part of the Forest Project) at the time of the Forest Project's offset project commencement date. The approved growth model or stand table projection used for the estimate must produce a result within 5 percent of current inventory data for pre-existing trees.

If the inventory of these carbon pools is deferred, the timing of the second verification is at the discretion of the Offset Project Operator or Authorized Project Designee (but must occur within 12 years of the initial verification). Reforestation Projects for which an initial inventory is deferred are not eligible to receive ARB or registry offset credits until after the second verification.

6.1.2 Estimating Baseline Carbon in Harvested Wood Products

Quantification Methodology

If harvesting of the pre-existing trees would be expected to occur in the baseline, the following steps must be performed:

1. Use a model (see Appendix B) to determine the *average* amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year of the baseline over 100 years. The result will be a uniform estimate of harvested carbon in each year of the baseline. This estimate is determined at offset project commencement using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the offset project crediting period.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.1.3 Determining Actual Onsite Carbon Stocks

Quantification Methodology

Actual carbon stocks for Reforestation Projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models and requirements and methods for projecting forest inventory plot data using models is provided in Appendix B.
3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the requirements and methods in Appendix A, Section A.4.

6.1.4 Determining Actual Carbon in Harvested Wood Products

Quantification Methodology

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.1.3).

2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.1.5 Quantifying Secondary Effects

Quantification Methodology

For Reforestation Projects, significant Secondary Effects can arise from two sources:

1. One-time combustion emissions associated with machinery used in site preparation; and
2. The shifting of cropland or grazing activities to forestland outside the Project Area (which may be both a market and/or physical response to the project activity), which is accounted for over the Project Life.

To quantify combustion emissions associated with site preparation, use the appropriate standard emission factor from Table 6.1 corresponding to the level of brush cover on the Project Area, multiplied by the number of acres in the Project Area (Equation 6.2).

Mobile combustion emissions must be added to Secondary Effect emissions (SE_y in Equation 6.1) in the first year of an offset project. If this results in a negative amount for total net quantified GHG reductions and GHG removal enhancements in year one (QR_1), the negative amount must be carried over into future years (N_{y-1} in Equation 6.1) until sufficient GHG reductions and GHG removal enhancements are accrued to achieve a positive balance. Negative GHG reductions and GHG removal enhancements due to site preparation emissions are *not* considered a reversal (Section 7.1).

Equation 6.2. Combustion Emissions Associated with Site Preparation

$$MC_y = (-1) \times (EF_{mc} \times PA)$$

Where,

MC_y = Secondary Effect CO_2e emissions due to mobile combustion from site preparation

EF_{mc} = Mobile combustion emission factor from Table 6.1

PA = The size of the Project Area, in acres

Table 6.1. Mobile Combustion Emissions for Reforestation Projects

SITE PREP - REFORESTATION PROJECTS Emissions Associated with Mobile Combustion		
Average Metric Tons CO_2e Per Acre		
Light	Medium	Heavy
25% Brush Cover	50% Dense Brush Cover	> 50% Brush Cover, stump removal
0.090	**0.202**	**0.429**

To quantify GHG emissions from the shifting of cropland and grazing activities each year, determine the appropriate "leakage" risk percentage for the project following the decision tree in Figure 6.3. The leakage risk percentage is only determined once, at offset project

commencement. Each year, this percentage must be applied to the net increase in onsite carbon stocks to determine the annual Secondary Effects due to shifting of cropland or grazing activities (Equation 6.3).

Equation 6.3. Emissions from Shifting Cropland and Grazing Activities

$$\mathbf{AS_y = (-1) \times L \times (\Delta\ AC_{onsite} - \Delta\ BC_{onsite})}$$

Where,

AS_y	=	Secondary Effect CO_2e emissions due to shifting of cropland or grazing activities
L	=	Leakage risk percentage, as determined from Figure 6.3
$\Delta\ AC_{onsite}$	=	Annual difference in actual onsite carbon (CO_2e) as defined in Equation 6.1.
$\Delta\ BC_{onsite}$	=	Annual difference in baseline onsite carbon (CO_2e) as defined in Equation 6.1.

Total Secondary Effect emissions for Reforestation Projects are calculated as follows (Equation 6.4). The value for Secondary Effect emissions will always be negative or zero.

Equation 6.4. Total Secondary Effect Emissions

$$\mathbf{SE_y = (AS_y + MC_y)}$$ *or* **0**, whichever is lower

Where,

SE_y	=	Secondary Effect GHG emissions caused by the project activity in year y (Equation 6.1)
AS_y	=	Secondary Effect CO_2e emissions due to shifting of cropland or grazing activities
MC_y	=	Secondary Effect CO_2e emissions due to mobile combustion from site preparation*

*Only occurs in year 1.

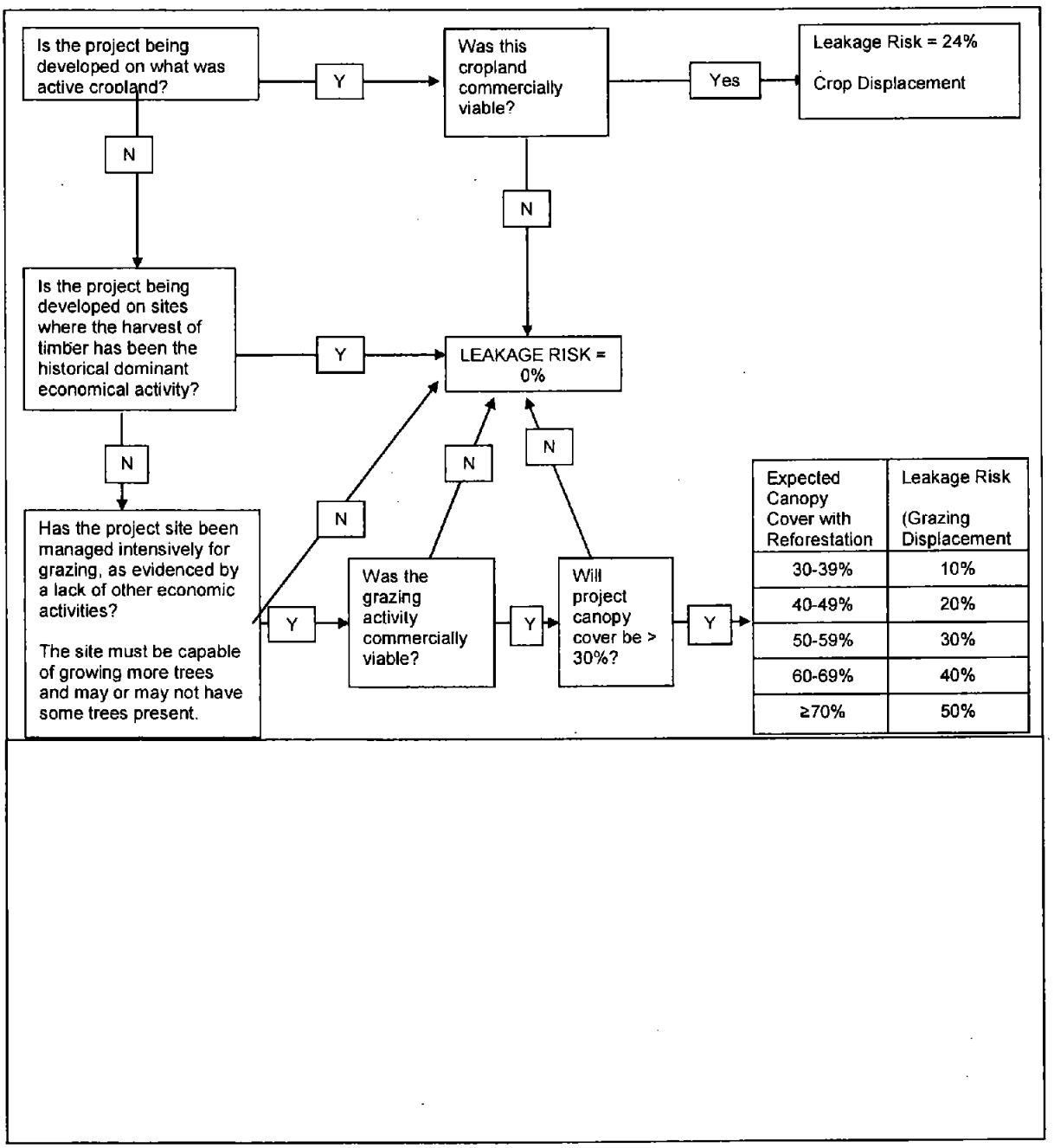


Figure 6.3. Activity Shifting ("Leakage") Risk Assessment for Reforestation Projects

6.2 Improved Forest Management Projects

Improved Forest Management Projects that take place on private land – or on land that is transferred to public ownership at the time the project is initiated – must estimate baseline onsite carbon stocks following the requirements and procedures in Section 6.2.1. Improved Forest Management Projects that take place on land that was publicly owned prior to the offset project commencement date must estimate baseline onsite carbon stocks following the requirements and procedures in Section 6.2.2. Requirements for determining baseline carbon in harvested wood products, determining actual onsite carbon stocks, determining actual carbon in harvested wood products, and quantifying Secondary Effects are the same for all Improved Forest Management Projects.

6.2.1 Estimating Baseline Onsite Carbon Stocks – Private Lands

Quantification Methodology

The baseline approach for Improved Forest Management Projects on private lands applies a standardized set of assumptions to offset project-specific conditions. A key assumption is that baseline carbon stocks will depend on how a project's initial standing live carbon stocks compare to "Common Practice," defined as the average standing live carbon stocks on similar lands within the Forest Project's Assessment Area. In addition, baseline carbon stocks must be adjusted to reflect management practice on the Forest Owner's other landholdings in instances where Project Area carbon stocks are more than 20 percent below the carbon stocks on land within the same logical management unit. Finally, the baseline must be modeled to reflect all legal and economic constraints affecting the Project Area.

The following steps must be followed to estimate baseline carbon stocks:

1. Determine the Common Practice level of above-ground standing live carbon stocks applicable to the Project Area.
2. Determine if the Project Area's initial above-ground standing live carbon stocks are above or below Common Practice.
3. Estimate baseline above-ground standing live carbon stocks, taking into account financial and legal constraints on harvesting in the Project Area, as well as the minimum baseline level applicable to the Project Area, as defined in the requirements for Step 3, below. The minimum baseline level will depend on whether initial above-ground standing live carbon stocks are above or below Common Practice.
4. Determine the baseline carbon stocks over 100 years for all required carbon pools in the Project Area.

For all calculations in this section, all values for "carbon stocks" should be expressed in metric tons of CO_2-equivalent.

Step 1 – Determine the Common Practice Carbon Stocks for the Project's Assessment Area

As defined in this protocol, Common Practice refers to the average stocks of above-ground standing live carbon associated with the Assessment Area(s) covered by the Project Area. Common Practice is used as a reference point for baseline estimation. To determine a value for Common Practice, see Appendix F and the data available in the Forest Offset Protocol Resources section of ARB's website.

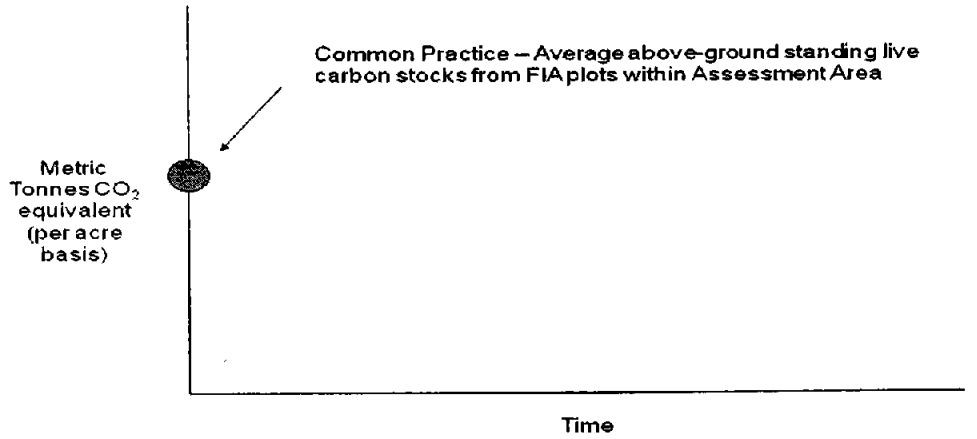


Figure 6.4. Common Practice as a Reference Point for Baseline Estimation

Step 2 – Determine if Initial Above-Ground Standing Live Carbon Stocks Are Above or Below Common Practice

To determine if initial above-ground standing live carbon stocks are above or below Common Practice, perform the following steps:

1. From the initial forest carbon inventory for the Project Area (conducted following the requirements in Appendix A), identify the metric tons of carbon contained in the *above-ground portion* of standing live carbon stocks.
2. Divide this amount by the number of acres in the Project Area.
3. Compare the result with the Common Practice value identified in Step 1.

Step 3 – Determine Baseline Above-Ground Standing Live Carbon Stocks

The baseline above-ground standing live carbon stocks must be determined by: (1) Modeling above-ground standing live carbon stocks through a series of growth and harvesting scenarios over 100 years; and (2) averaging the model results over the 100-year timeframe, so that the baseline is expressed as a single (average) value for above-ground standing live carbon stocks per acre in every year. The modeling must be performed following the requirements and methods in Appendix B and must meet the following conditions:

1. Growth and harvesting scenarios must reflect all legal constraints, following the requirements in Section 6.2.1.2.
2. Growth and harvesting scenarios must reflect any financial constraints, following the requirements in Section 6.2.1.3.
3. The averaged model results, expressed as above-ground standing live carbon stocks per acre, must not fall below a minimum baseline level (MBL). If initial above-ground standing live carbon stocks are above Common Practice, the MBL must be determined using the formula in Equation 6.5. If initial above-ground standing live carbon stocks are below Common Practice, then MBL must be determined using the formula in Equation 6.6.

A graphical example of a baseline meeting these conditions is provided in Figure 6.5 and Figure 6.6. Figure 6.5 shows the baseline before averaging; Figure 6.6 shows the baseline after averaging.

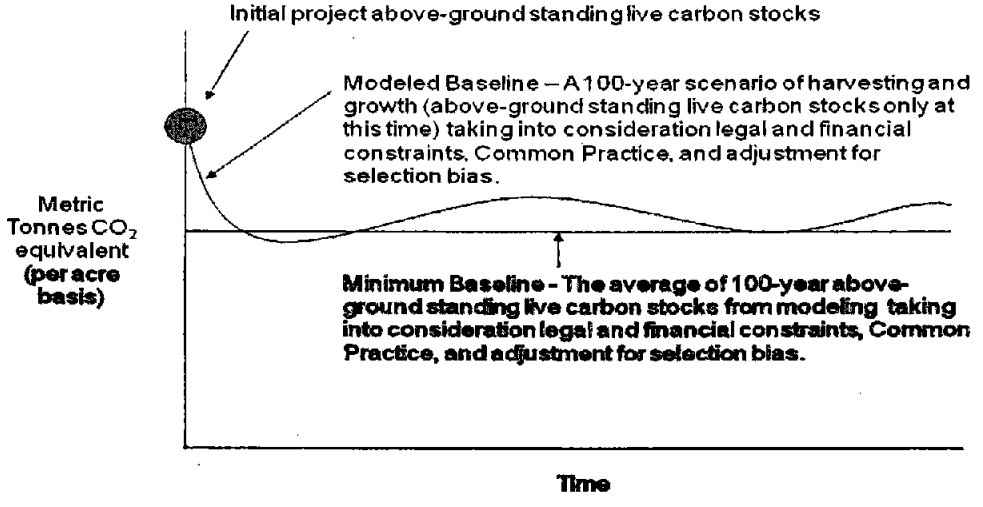


Figure 6.5. Modeling Standing Live Carbon Stocks Where Initial Stocks Are Above Common Practice

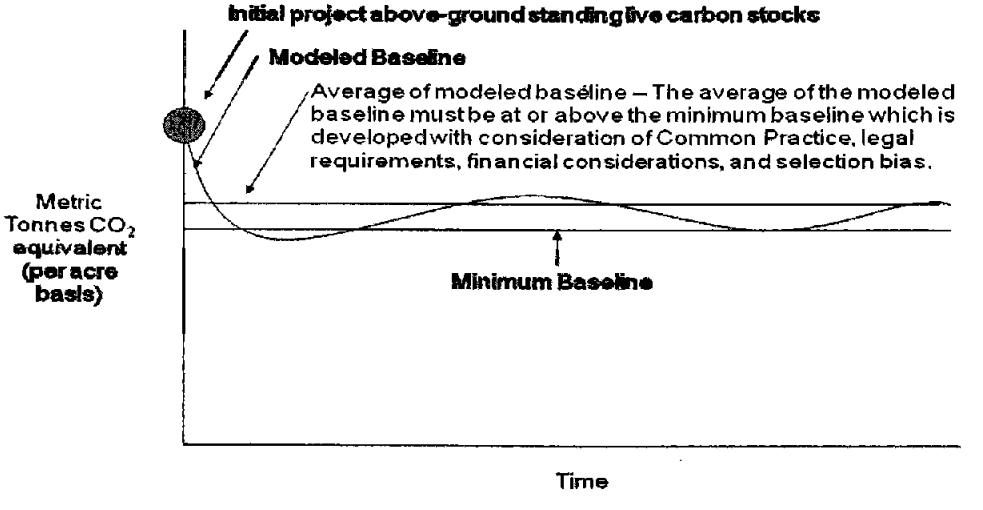


Figure 6.6. Averaging the Modeled Standing Live Carbon Stocks Where Initial Stocks Are Above Common Practice

Equation 6.5. Determining the Minimum Baseline Level Where Initial Stocks Are Above Common Practice

MBL = CP

Where,

MBL	=	Minimum baseline level (above-ground standing live carbon stocks)
CP	=	Common Practice (as determined in Step 1)

Equation 6.6. Determining the Minimum Baseline Level Where Initial Stocks Are Below Common Practice

MBL = MAX (MAX (HSR, ICS), MIN (CP, WCS))

Where,

MAX	=	The highest value in the set of values being evaluated.
MIN	=	The lowest value in the set of values being evaluated.
MBL	=	Minimum baseline level (above-ground standing live carbon stocks)
HSR	=	The "High Stocking Reference" for the Project Area. The High Stocking Reference is defined as 80 percent of the highest value for above-ground standing live carbon stocks per acre within the Project Area during the preceding 10-year period. To determine the High Stocking Reference, the Offset Project Operator or Authorized Project Designee must document changes in the Project Area's above-ground standing live carbon stocks over the preceding 10 years. Figure 6.7 presents a graphical portrayal of a High Stocking Reference determination.
CP	=	Common Practice (as determined in Step 1)
ICS	=	Initial above-ground standing live carbon stocks per acre within the Project Area (as determined in Step 2)
WCS	=	The weighted average above-ground standing live carbon stocks per acre for all Forest Owner (and affiliate) landholdings within the same logical management unit as the Project Area. See Section 6.2.1.1 for requirements and methods for calculating WCS.

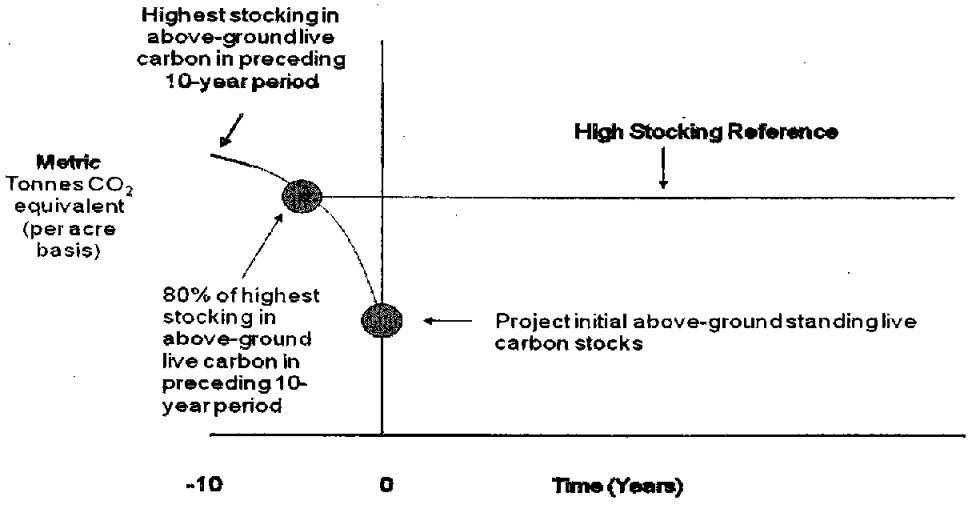


Figure 6.7. Determining a Project Area's High Stocking Reference
Note: It is possible for the High Stocking Reference to be higher than Common Practice, even where initial live-tree carbon stocks for the project are below Common Practice.

Step 4 – Determine the Baseline for All Carbon Pools

Once the baseline for above-ground standing live carbon stocks has been determined, perform the following steps:

1. Estimate baseline carbon stocks for all other required carbon pools identified for the offset project (including below-ground carbon stocks, as well as standing dead carbon stocks where applicable). These carbon stocks must be modeled or estimated following the requirements and methods in Appendix A and Appendix B.
2. Average the results, so that the baseline for other carbon pools contains the same (average) value for carbon stocks in every year.
3. Sum the above-ground standing live carbon stock baseline and the baseline for all other carbon stocks to produce a final baseline for all carbon pools (see Figure 6.8).

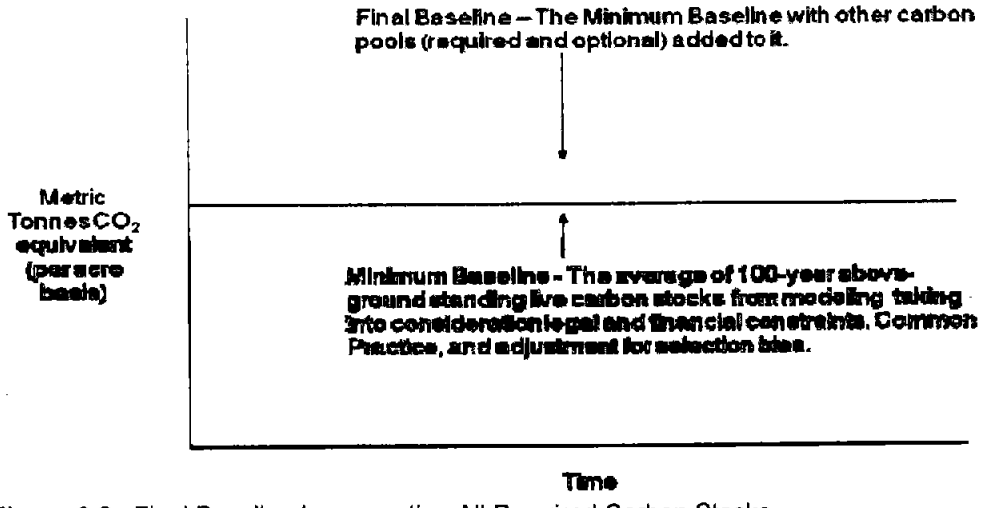


Figure 6.8. Final Baseline Incorporating All Required Carbon Stocks

6.2.1.1 Determining Weighted Average Carbon Stocks (WCS) on Lands in the Same Logical Management Unit as the Project Area

Quantification Methodology
Determining the minimum baseline level (MBL) for an Improved Forest Management project requires a comparison to carbon stocking levels on other lands within the same logical management unit (LMU) as the Project Area. The carbon stocking level within the LMU (expressed as the weighted average above-ground standing live carbon stocks per acre for all lands in the same LMU) is used as a parameter (WCS) for determining the MBL in Equation 6.6.

A "logical management unit" or "LMU" is defined as all land that the Forest Owner and its affiliate(s) (as defined below) either own in fee or hold timber rights on, and which it or they manage as an explicitly defined planning subunit. LMUs are generally characterized by unique biological, geographical, and/or geological conditions, are generally delimited by watershed boundaries and/or elevational zones, and contain unique road networks. In addition, an LMU must:

- Be a sustainable planning subunit as demonstrated by inventory reports and growth and harvest projections for the LMU or;
- Where even aged management is utilized, have a uniform distribution (by area) of 10-year age classes that extend to the normal rotation age (variation of any 10-year age class not to exceed 20%) or;
- Where uneven aged management is utilized, have between 33% and 66% of the forested stands exceeding the retention standards identified in the growth and harvest projections by a minimum of 25% (basal area).

An "affiliate" is defined as any person or entity that, directly or indirectly, through one or more intermediaries, controls or is controlled by or is under common control with the Forest Owner, including any general or limited partnership in which the Forest Owner is a partner and any limited liability company in which the Forest Owner is a member. For the purposes of this definition, "control" means the possession, direct or indirect, of the power to direct or cause the

direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise, and "person" means an individual or a general partnership, limited partnership, corporation, professional corporation, limited liability company, limited liability partnership, joint venture, trust, business trust, cooperative or association or any other legally-recognized entity.

If an explicit, existing LMU containing the Project Area cannot be identified, the LMU must be defined by identifying all lands where the Forest Owner and its affiliate(s) (as defined above) either own in fee or hold timber rights within the same Assessment Area(s) covered by the Project Area. Assessment Areas covered by the Project Area are identified in Step 1, above, using the information in Appendix F.

To calculate WCS, estimate the above-ground standing live carbon stocks per acre for the entire LMU containing the Project Area (including the Project Area itself). This can be done using either existing inventory data, or a stratified vegetation-type analysis.

6.2.1.1.1 Calculating WCS Using Inventory Data

Quantification Methodology

If sufficient inventory data for LMU lands exist to quantify above-ground standing live carbon stocks for the entire LMU, then the formula in Equation 6.7 must be used to calculate WCS.

Equation 6.7. Formula for WCS Using Inventory Data

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| \leq 0.2, then\ WCS = ICS$$

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| > 0.2, then\ WCS = \frac{ICS \cdot PA + ECS \cdot EA}{PA + EA}$$

Where,

WCS = The weighted average above-ground standing live carbon stocks per acre within the LMU containing the Project Area

ICS = Initial above-ground standing live carbon stocks per acre within the Project Area

PA = Size of the Project Area in acres

ECS = Above-ground standing live carbon stocks per acre within the LMU *but excluding the Project Area* (EA), as determined from existing inventory data

EA = Size of the LMU in acres, e*xcluding the Project Area*

6.2.1.1.2 Calculating WCS Using Stratified Vegetation-Type Analysis

Quantification Methodology

If sufficient inventory data is not available for the LMU, a stratified vegetation-type analysis must be used to calculate WCS. To conduct this analysis, all landholdings within the LMU – including the Project Area – must be divided into vegetation types and size class/canopy cover categories as delimited in Table 6.2 with a resolution for classification no greater than 40 acres. Each vegetation class has a "carbon rating" provided in Table 6.2. WCS must be calculated using the

ratio of average carbon stocking on LMU lands relative to carbon stocking on Project Area lands (referred to as the "stratified carbon weighting factor" or SWF). The required formulas are specified in Equation 6.8 and Equation 6.9.

Equation 6.8. Formula for WCS Using Stratified Vegetation-Type Analysis

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| \leq 0.2, then\ WCS = ICS$$

$$If \left|\left(1-\frac{ECS}{ICS}\right)\right| > 0.2, then\ WCS = \frac{ICS \cdot PA + SWF \cdot ICS \cdot EA}{PA + EA}$$

Where,

WCS = The weighted average above-ground standing live carbon stocks per acre within the LMU containing the Project Area

ECS = Above-ground standing live carbon stocks per acre within the LMU, but excluding the Project Area (EA), as determined from existing inventory data

ICS = Initial above-ground standing live carbon stocks per acre within the Project Area

PA = Size of the Project Area in acres

SWF = The stratified carbon weighting factor for the LMU (from Equation 6.9 below)

EA = Size of the LMU in acres, e*xcluding the Project Area*

Equation 6.9. Formula for LMU Stratified Carbon Weighting Factor

$$SWF = \frac{\sum_i (PA_i \cdot CR_i)}{\sum_i PA_i} \div \frac{\sum_i (EA_i \cdot CR_i)}{\sum_i EA_i}$$

Where,

PA_i = Acres of the Project Area in forest vegetation type *i* (from Table 6.2)

EA_i = Acres of the LMU, e*xcluding the Project Area,* in forest vegetation type *i* (from Table 6.2)

CR_i = Carbon rating for forest vegetation type *i* (from Table 6.2)

Table 6.2. Vegetation Classes for Stratification

Forest Vegetation Description	Average Diameter (Breast Height)	Average Canopy Cover	Carbon Rating (metric tons CO_2e)
Brush	0"	NA	0
Regeneration	3"	NA	0.5
Pole-sized trees	6" - 12"	< 33%	2
Pole-sized trees	6" - 12"	33% - 66%	4
Pole-sized trees	6" - 12"	>66%	6
Small Sawlogs	12" - 20"	< 33%	4
Small Sawlogs	12" - 20"	33% - 66%	8
Small Sawlogs	12" - 20"	>66%	12
Large Sawlogs	20" - 36"	< 33%	8
Large Sawlogs	20" - 36"	33% - 66%	16
Large Sawlogs	20" - 36"	>66%	24
Very Large Trees	>36"	< 33%	16
Very Large Trees	>36"	33% - 66%	32
Very Large Trees	>36"	>66%	48

6.2.1.2 Consideration of Legal Constraints

In modeling the baseline for standing live carbon stocks, all legal constraints that could affect baseline growth and harvesting scenarios must be incorporated. The standing live carbon stock baseline must represent a growth and harvesting regime that fulfills all legal requirements. Voluntary agreements that can be rescinded, such as rental contracts and forest certifications, are not legal constraints. Habitat Conservation Plans (HCPs) and Safe Harbor Agreements (SHAs) that are in place more than one year prior to the offset project commencement date shall be modeled as legal constraints. HCPs and SHAs that are approved after the date one year prior to the offset project's commencement date are not considered legal constraints for the purpose of baseline modeling and may be disregarded from the baseline modeling.

Legal constraints include all laws, regulations, and legally-binding commitments applicable to the Project Area at the time of offset project commencement that could affect standing live carbon stocks. Legal constraints include:

1. Federal, state, or local government regulations that are required and might reasonably be anticipated to influence carbon stocking over time including, but not limited to:
    a. Zones with harvest restrictions (e.g. buffers, streamside protection zones, wildlife protection zones)
    b. Harvest adjacency restrictions
    c. Minimum stocking standards
2. Forest practice rules, or applicable Best Management Practices established by federal, state, or local government that relate to forest management.
3. Other legally binding requirements affecting carbon stocks including, but not limited to, covenants, conditions and restrictions, and other title restrictions in place prior to or at the time of project initiation, including pre-existing conservation easements, Habitat Conservation Plans, Safe Harbor Agreements, and deed restrictions, excepting an

encumbrance that was put in place and/or recorded less than one year prior to the offset project commencement date, as defined in Section 3.5.

For forest projects located in California, the baseline must be modeled to reflect all silvicultural treatments associated with any submitted, active, or approved timber harvest plans (THPs) at the time of offset project commencement that would affect harvesting and management within the Project Area during the Project Life. All legally enforceable silvicultural and operational provisions of a THP – including those operational provisions designed to meet California Forest Practice Rules requirements for achieving Maximum Sustained Production of High Quality Wood Products [14 CCR 913.11 (933.11, 953.11)] – are considered legal constraints and must be reflected in baseline modeling for as long as the THP will remain active. For portions of the Project Area not subject to THPs (or over time periods for which THPs will not be active), baseline carbon stocks must be modeled by taking into account any applicable requirements of the California Forest Practice Rules and all other applicable laws, regulations, and legally binding commitments that could affect onsite carbon stocks. On a case-by-case basis, the California Department of Forestry and Fire Protection (Cal FIRE) may assist in identifying minimum carbon stocking levels that would be effectively required under California Forest Practice Rules.

6.2.1.3 Consideration of Financial Constraints

In modeling the baseline for standing live carbon stocks, financial constraints that could affect baseline growth and harvesting scenarios must be included. It must be demonstrated that the growth and harvesting regime assumed for the baseline is financially feasible through one of the following means:

1. A financial analysis of the anticipated growth and harvesting regime that captures all relevant costs and returns, taking into consideration all legal, physical, and biological constraints. Cost and revenue variables in the financial analysis may be based on regional norms or on documented costs and returns for the Project Area or other properties in the Forest Project's Assessment Area.
2. Providing evidence that activities similar to the proposed baseline growth and harvesting regime have taken place on other properties within the Forest Project's Assessment Area within the past 15 years. The evidence must demonstrate that harvesting activities have taken place on at least one other comparable site with:
    a. Slopes that do not exceed slopes in the Project Area by more than 10 percent
    b. An equivalent zoning class to the Project Area
    c. Comparable species composition to the Project Area (i.e. within 20 percent of project species composition based on trees per acre)

6.2.2 Estimating Baseline Onsite Carbon Stocks – Public Lands

Quantification Methodology

For Improved Forest Management Projects on lands owned or controlled by public agencies, the baseline must be estimated by:

1. Conducting an initial forest carbon inventory for the Project Area
2. Projecting future changes to Project Area forest carbon stocks by:
    a. Extrapolating from historical trends
    b. Anticipating how current and future public policy will affect onsite carbon stocks

The method that results in the highest estimated carbon stock levels must be used to determine the baseline.

To extrapolate from historical trends:

- For Project Areas that have a ten-year history of declining carbon stocks, the baseline must be defined by the average of the carbon stocks over the past ten years and considered static for the project life (i.e. the same level of carbon stocks is assumed in every year).
- For Project Areas that demonstrate an increasing inventory of carbon stocks over the past ten years, the growth trajectory of the baseline shall continue until the forest (under the baseline stocks) achieves a stand composition consistent with comparable forested areas that have been relatively free of harvest over the past 60 years.

To anticipate how current and future public policy will affect onsite carbon stocks, the baseline must be modeled following the requirements and methods in Appendix B incorporating constraints imposed by all applicable statutes, regulations, policies, plans and Activity-Based Funding.

6.2.3 Estimating Baseline Carbon in Harvested Wood Products

Quantification Methodology

To estimate the amount of baseline carbon transferred to long-term storage in wood products each year, the following steps must be performed:

1. Determine the *average* amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year of the baseline over 100 years. The result will be a uniform estimate of harvested carbon in each year of the baseline. This estimate is determined at offset project commencement, using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the project.
    a. For offset projects on private lands, the amount of harvested carbon must be derived from the growth and harvesting regime used to develop the baseline for onsite carbon stocks in Section 6.2.1.
    b. For offset projects on public lands, the amount of harvested carbon must be derived from the growth and harvesting regime assumed in the baseline for onsite carbon stocks derived in Section 6.2.2.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.2.4 Determining Actual Onsite Carbon Stocks

Quantification Methodology

Actual carbon stocks for Improved Forest Management projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models and requirements and methods for projecting forest inventory plot data using models are provided in Appendix B.
3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the requirements and methods in Appendix A, Section A.4.

6.2.5 Determining Actual Carbon in Harvested Wood Products

Quantification Methodology

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.2.4).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.2.6 Quantifying Secondary Effects

Quantification Methodology

For Improved Forest Management Projects, significant Secondary Effects can occur if a project reduces harvesting in the Project Area, resulting in an increase in harvesting on other properties. Equation 6.10 must be used to estimate Secondary Effects for Improved Forest Management projects:

Equation 6.10. Secondary Effects Emissions

$$If \sum_{n=1}^{y}(AC_{hv,n} - BC_{hv,n}) > 0, then\ SE_y = 0$$

$$If \sum_{n=1}^{y}(AC_{hv,n} - BC_{hv,n}) < 0, then\ SE_y = (AC_{hv,y} - BC_{hv,y}) \times 20\%$$

Where,

SE_y	=	Estimated annual Secondary Effects (used in Equation 6.1.)
$AC_{hv,n}$	=	Actual amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons
$BC_{hv,n}$	=	Estimated average baseline amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons, as determined in Step 1 of Section 6.2.3
Y	=	The current year or reporting period

6.3 Avoided Conversion Projects

6.3.1 Estimating Baseline Onsite Carbon Stocks

Quantification Methodology

The baseline for Avoided Conversion Projects is a projection of onsite forest carbon stock losses that would have occurred over time due to the conversion of the Project Area to a non-forest land use. Estimating the baseline for Avoided Conversion Projects involves two steps:

1. Characterizing and projecting the baseline; and
2. Discount for the uncertainty of conversion probability.

Step 1 - Characterizing and Projecting the Baseline

The project baseline must be characterized by:

1. Clearly specifying an alternative highest-value land use for the Project Area, as identified by an appraisal (required in Section 3.1.2.3).
2. Estimating the rate of conversion and removal of onsite carbon stocks, taking into consideration any laws, statutes, regulations, or other legal mandates that affect land use conversion or removal of onsite carbon stocks. The rate of conversion and removal of onsite carbon stocks must be estimated by either:
    a. Referencing planning documentation for the Project Area (e.g. construction documents or plans) that specifies the timeframe of the conversion and intended removal of forest cover on the Project Area; or
    b. In the absence of specific documentation, identifying default Total Conversion Impact and Annual Conversion values from Table 6.3.
3. Using a computer simulation to project changes in onsite carbon stocks over 100 years, reflecting the rate of conversion estimated in (2). The simulation must model changes in onsite carbon stocks for all required carbon pools, as identified in Section 5.3.

Table 6.3. Default Avoided Conversion

Type of Conversion Identified in Appraisal	Total Conversion Impact This is the assumed total effect over time of the conversion activity. (The total conversion impact is amortized over a 10-year period to determine the annual conversion in the next column.)	Annual Conversion This is the assumed annual conversion activity. The percentages below are multiplied by the initial onsite carbon stocks for the project on an annual basis for the first 10 years of the project.
Residential	Estimate using the following formula: TC = min(100, (P*3 / PA)*100) *Where:* TC = % total conversion (TC cannot exceed 100%) PA = the Project Area (acres) identified in the appraisal P = the number of unique parcels that would be formed on the project area as identified in the appraisal *Each parcel is assumed to deforest 3 acres of forest vegetation.	Estimate using the following formula: AC = TC / 10 *Where:* AC = % annualized conversion TC = % total conversion
Mining and agricultural conversion, including pasture or crops	90%	9.0%
Golf course	80%	8.0%
Commercial buildings	95%	9.5%

The computer simulation of the baseline must apply the identified rate of conversion over time to estimate changes in onsite carbon stocks, beginning with the Project Area's initial onsite carbon stocks.

If the projected conversion rate does not result in a complete removal of onsite forest carbon stocks, the baseline projection should account for any residual forest carbon value as a steady condition for the balance of a 100-year projection.

Step 2 - Discount for Uncertainty of Conversion Probability

If the fair market value of the anticipated alternative land use for the Project Area (as determined by the appraisal required in Section 3.1.2.3) is *not more than 80 percent greater* than the value of the current forested land use, then a discount must be applied each year to the offset project's quantified GHG reductions and GHG removal enhancements. If quantified GHG reductions and GHG removal enhancements for the year are positive (i.e. $[(\Delta\ AC_{onsite} - \Delta\ BC_{onsite}) + (AC_{wp,\ y} - BC_{wp,\ y}) * 80\% + SE_y] > 0$ in Equation 6.1) then use the following formula (Equation 6.11) to calculate the appropriate Avoided Conversion Discount factor, ACD. If quantified GHG reductions and removals for the year are negative, then ACD must equal zero.

Equation 6.11. Avoided Conversion Discount Factor

If $0.4 < ((VA / VP) - 1) < 0.8$, **then** $ACD = [80\% - ((VA / VP) - 1)] \times 2.5$
If $((VA / VP) - 1) > 0.8$, **then** $ACD = 0\%$
If $((VA / VP) - 1) < 0.4$, **then** $ACD = 100\%$

Where,

ACD	=	The Avoided Conversion Project discount factor (used in Equation 6.1).
VA	=	The appraised fair market value of the anticipated alternative land use for the Project Area
VP	=	The appraised fair market value of the current forested land use for the Project Area

6.3.2 Estimating Baseline Carbon in Harvested Wood Products

Quantification Methodology

Harvesting is assumed to occur in the baseline over time as the Project Area is converted to another land use. To estimate the baseline carbon transferred to long-term storage in harvested wood products each year:

1. Determine the amount of carbon in standing live carbon stocks (prior to delivery to a mill) that would have been harvested in each year, consistent with the rate of reduction in baseline standing live carbon stocks determined in Section 6.3.1. This projection is determined at offset project commencement, using the same biomass equations used to calculate biomass in live trees, and will not change over the course of the offset project.
2. On an annual basis, determine the amount of harvested carbon that would have remained stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.3.3 Determining Actual Onsite Carbon Stocks

Quantification Methodology

Actual carbon stocks for Avoided Conversion Projects must be determined by updating the Project Area's forest carbon inventory. This is done by:

1. Incorporating any new forest inventory data obtained during the previous year into the inventory estimate. Any plots sampled during the previous year must be incorporated into the inventory estimate.
2. Using an approved model to "grow" (project forward) prior-year data from existing forest inventory plots to the current reporting year. Approved growth models are identified in Appendix B. Methods for projecting forest inventory plot data using models is also provided in Appendix B.
3. Updating the forest inventory estimate for harvests and/or disturbances that have occurred during the previous year.
4. Applying an appropriate confidence deduction for the inventory based on its statistical uncertainty, following the requirements and methods in Appendix A, Section A.4.

6.3.4 Determining Actual Carbon in Harvested Wood Products

Quantification Methodology

Perform the following steps to determine actual carbon in harvested wood products:

1. Determine the actual amount of carbon in standing live carbon stocks (prior to delivery to a mill) harvested in the current year (based on harvest volumes determined in Section 6.3.3).
2. Determine the amount of actual harvested carbon that will remain stored in wood products, averaged over 100 years, following the requirements and methods in Appendix C.

6.3.5 Quantifying Secondary Effects

Quantification Methodology

Significant Secondary Effects for Avoided Conversion projects can arise if the type of land use conversion that would have happened on the Project Area is shifted to other forest land.

To quantify Secondary Effects for Avoided Conversion projects, use Equation 6.12.

The value for Secondary Effect emissions will always be negative or zero.

Equation 6.12. Secondary Effects Emissions

$$SE_y = (-1) \times CDR\% \times (\Delta AC_{onsite} - \Delta BC_{onsite}) \text{ or } 0, \text{ whichever is lower}$$

Where,

SE_y	=	Secondary Effect GHG emissions caused by the project activity in year y (Equation 6.1)
CDR	=	Conversion displacement risk value, assumed to be 3.6% for all forest lands
ΔAC_{onsite}	=	Annual difference in actual onsite carbon (CO_2e) as defined in Equation 6.1
ΔBC_{onsite}	=	Annual difference in baseline onsite carbon (CO_2e) as defined in Equation 6.1

7 Ensuring the Permanence of Credited GHG Reductions and GHG Removal Enhancements

The Regulation requires that credited GHG reductions and GHG removal enhancements be "permanent." Permanence of Forest project GHG reductions and removals is addressed through three mechanisms:

1. The requirement for all offset projects to monitor onsite carbon stocks, submit annual Offset Project Data Reports, and undergo third-party verification of those reports with site visits at least every six years for the duration of the Project Life.
2. The regulatory obligation for all intentional reversals of GHG reductions and GHG removal enhancements to be compensated for through retirement of other Compliance Instruments.
3. The maintenance of a Forest Buffer Account by ARB to provide insurance against reversals of GHG reductions and GHG removal enhancements due to unintentional causes (including natural disturbances such a fires, pest infestations, or disease outbreaks).

GHG reductions and GHG removal enhancements can be "reversed" if the stored carbon associated with them is released (back) to the atmosphere. Many biological and non-biological agents, both natural and human-induced, can cause reversals. Some of these agents cannot completely be controlled and may therefore result in an unintentional reversal, such as natural agents like fire, insects, and wind. Other agents can be controlled, such as the human activities like land conversion and over-harvesting. Under this protocol, reversals due to controllable agents are considered intentional as defined in the Regulation. The Offset Project Operator or Authorized Project Designee is required to identify and quantify the risk of reversals from different agents based on offset project-specific circumstances. The resulting risk rating determines the quantity of ARB offset credits that the project must contribute to the Forest Buffer Account to insure against unintentional reversals.

7.1 Identifying a Reversal

The Offset Project Operator or Authorized Project Designee must demonstrate, through annual reporting and periodic verification, that stocks associated with credited GHG reductions and GHG removal enhancements are maintained for a period of time considered to be permanent. For purposes of this protocol 100 years is considered permanent. If the quantified GHG reductions and GHG removal enhancements (i.e. QR_y in Equation 6.1) in a given year are negative, and ARB offset credits were issued to the Forest Project in any previous year, it is considered a reversal, regardless of the cause of the decrease. Planned thinning or harvesting activities, for example, may cause a reversal if they result in a negative value for QR_y.

7.2 Insuring Against Reversals

Unintentional reversals are insured against by contributing a percentage of ARB offset credits to a Forest Buffer Account. The amount of the contribution is based on a project-specific risk evaluation.

7.2.1 About the Forest Buffer Account

A Forest Buffer Account is a holding account for ARB offset credits issued to Forest Project, which is administered by ARB. All Forest Projects must contribute a percentage of ARB offset

credits to the Forest Buffer Account any time ARB offset credits are issued by ARB for verified GHG reductions and GHG removal enhancements. Each Forest Project's contribution is determined by a project-specific risk rating, as described in Section 7.2.2. If a Forest Project experiences an unintentional reversal of credited GHG reductions and GHG removal enhancements (as defined in Section 7.3), ARB offset credits from the Forest Buffer Account will be retired in an amount equal to the total amount of carbon that was reversed (measured in metric tons of CO_2-equivalent) according to the process identified in the Regulation. A Forest Buffer Account therefore acts as a general insurance mechanism against unintentional reversals for ARB offset credits issued to Forest Projects.

7.2.2 Contributions to the Forest Buffer Account

ARB offset credits will be contributed to the Forest Buffer Account pursuant to the Regulation based on the reversal risk rating for a project as determined by the requirements and methods in Appendix D. The risk rating must be determined prior to listing, and recalculated in every year the project undergoes verification. Forest Owners who record a Qualified Conservation Easement in conjunction with implementing a Forest Project will receive a lower risk rating (see Appendix D).

7.3 Compensating for Reversals

The Regulation defines reversals and establishes how reversals will be compensated.

7.3.1 Unintentional Reversals

The Regulation defines unintentional reversals. Requirements for compensating unintentional reversals are set forth in the Regulation.

7.3.2 Intentional Reversals

The Regulation defines intentional reversals. Requirements for intentional reversals are set forth in the Regulation.

7.4 Disposition of Forest Projects after a Reversal

Provisions related to the disposition of a Forest Project after a reversal are set forth in the Regulation. These provisions dictate under what circumstances a Forest Project that undergoes an intentional or unintentional reversal would be terminated and under what circumstances the Forest Project may continue without termination.

8 Offset Project Monitoring

General requirements for monitoring, reporting, and record retention are provided in the Regulation. The Offset Project Operator or Authorized Project Designee must conduct monitoring activities and submit Offset Project Data Reports in accordance with the Regulation and this protocol. Monitoring is required for a period of 100 years following the final issuance of any ARB or registry offset credits to an offset project.

For Forest Projects, monitoring activities consist primarily of updating a project's forest carbon inventory. ARB requires a complete inventory of carbon stocks to be reported each year. This complete inventory must be maintained and updated throughout the Project Life.

8.1 Forest Carbon Inventory Program

Prior to a Forest Project's first verification, a documented forest carbon inventory program, including an inventory monitoring plan and a modeling plan, must be established detailing the specific methods that will be used to update the project's forest carbon inventory on an annual basis. The forest carbon inventory program must adhere to the requirements and methods in Appendices A and B, which establish the equations for computing biomass and limits to which computer models can be used in the inventory update process.

8.2 Annual Monitoring Requirements

The Offset Project Operator or Authorized Project Designee is required to report the Forest Project's onsite carbon stocks each year in an Offset Project Data Report. The Offset Project Data Report must include an estimate of carbon stocks in all required carbon pools. The estimate must reflect the appropriate confidence deduction as determined by the steps in Appendix A, Section A.4. Annual onsite carbon stock estimates are computed from inventory data. Inventory data are updated annually by:

1. Incorporating any new forest inventory data obtained during the previous year.
2. Modeling growth in sample plots using approved growth models and stand table projection methods (see Appendix B regarding growth models and stand table projections).
3. Updating the forest inventory data for harvests and/or disturbances that have occurred during the previous year.

Specific methods used to update the forest inventory must follow the inventory methodologies approved at the time the project is initially verified. Modifications to inventory methodologies must be approved in advance by a third-party verification body and by ARB, and documented in the change log.

9 Reporting Requirements

This section provides supplemental requirements for reporting in addition to requirements contained in the Regulation. Offset Project Data Reports must be submitted at the conclusion of every Reporting Period.

9.1 Offset Project Documentation

In order for the offset project to be Listed, all of the information specified in the Project Listing Requirements in Section 9.1.1 must be submitted, along with any additional information specified in the Regulation. Reporting deadlines and record retention requirements are contained in the Regulation.

All reports that reference carbon stocks must be submitted with the oversight of a Professional Forester. If the offset project is located in a jurisdiction without a Professional Forester law or regulation, then a Professional Forester must either have the Certified Forester credentials managed by the Society of American Foresters, or other valid professional forester license or credential approved by a government agency in a different jurisdiction.

9.1.1 Offset Project Listing Requirements

The listing information in this section must be submitted by the Offset Project Operator or Authorized Project Designee prior to the Listing of the offset project. This information is also submitted as part of the first Offset Project Data Report, and is subject to verification at the initial offset project verification. The following listing information must be submitted no later than the date at which the Offset Project Operator or Authorized Project Designee submits the first Offset Project Data Report:

9.1.1.1 All Offset Projects[7]

1. Offset project name.
2. Offset project contact information, including name, phone number, address, and email address for:
   a. Offset Project Operator
   b. Authorized Project Designee (if applicable);
3. Whether the Offset Project Operator is the owner in fee for the project area.
   a. If yes, provide documentation (e.g. deed of trust, title report) showing the Offset Project Operator's ownership interest in the property and its interest in the trees and standing timber on the property.
   b. If no, explain how the entity identified as the Offset Project Operator has the right to undertake and list the project and provide documentation supporting the explanation.
4. Offset project type (reforestation, improved forest management, or avoided conversion).
5. A description of the management activities that will lead to increased carbon stocks in the Project Area, compared to the baseline.

[7] Reforestation projects as qualified in section 6.1 can defer the items that are marked with an asterisk until the second site-visit verification.

6. Indicate if the offset project occurs on public or private lands, and further specify if the offset 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.
7. Offset project commencement date, with an explanation and justification of the commencement date.
    a. Specify the action(s) that identify the offset project commencement date.
8. A statement as to whether any GHG reductions or GHG removal enhancements associated with the Project Lands have ever been listed or registered with, or otherwise claimed by, another registry or program, or sold to a third party prior to listing, including;
    a. Have any lands within the Project Area ever been listed or registered with an offset project registry or program in the past?
    b. Have greenhouse gas emission reductions or removal enhancements associated with lands within the Project Area been credited or claimed for the purpose of greenhouse gas mitigation or reduction goals, whether in a voluntary or regulatory context?
    c. If yes, identify the registry or program (include vintages and reporting period).
9. A statement as to whether the project is being implemented and conducted as the result of any law, statute, regulation, court order, or other legally binding mandate? If yes, explain.
10. Declaration that the offset project does *not* employ broadcast fertilization.
11. If the Forest Project is located on public land, a description and copies of the documentation demonstrating explicit approval of the offset project's management activities and baseline including any public vetting processes necessary to evaluate management and policy decisions concerning the offset project.
12. If the Forest Project is located on the following categories of land, a description and copies of documentation demonstrating that the land within the Project Area is owned by a tribe or private entities:
    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.
13. If commercial harvesting is either planned or ongoing within the Project Area, a description of how the Forest Owner satisfies one of the three requirements for employing and demonstrating sustainable long-term harvesting practices on all of its forest landholdings (refer to Section 3.8.1).
14. A description of how the offset project meets (or will meet) the definition of "Natural Forest Management" (refer to Section 3.8.2), including:
    a. Composition of native species;
    b. Distribution of age classes / sustainable management;
    c. Structural elements (standing and lying dead wood);
15. Descriptions and maps of the Project Area boundaries that include:
    a. Governing jurisdictions, and latitude/longitude coordinates
    b. Public and private roads (map)
    c. Towns (map)

d. Major watercourses (4th order or greater), water bodies, and watershed description (map)
e. Topography (map)
f. Townships, ranges, and sections or latitude and longitude (map)
g. Existing land cover and land use (description with optional map)
h. Forest vegetation types (description with optional map)
i. Site classes (description with optional map)
j. Land pressures and climate zone/classification (description with optional map)
k. Historical land uses, current zoning, and projected land use within project area and surrounding areas (description with optional map)
l. A georeferenced shape file (or other electronic file that can be read in a geographic information system) that clearly identifies the project area and boundaries. This file may constitute the required map if it includes the required map information listed above.

16. Identify what assessment area or areas contain lands within the Project Area.
    a. Include how many acres of project lands fall within each assessment area.
    b. Include a value for total project area acreage.
17. General description of the forest conditions within the Project Area:
    a. Species (tree) composition;
    b. Age class distribution;
    c. Management history;
18. Indicate whether the project will employ a Qualified Conservation Easement.
    a. If yes, include the date the Qualified Conservation Easement was or will be recorded, the terms that affect forest management within the easement, and provide a copy of the Qualified Conservation Easement to ARB.
19. *A description of the inventory methodology for each of the carbon pools included in the Forest Project's Offset Project Boundary. The inventory methodology must describe the information required in Appendix A.3.
20. *A description of the calculation methodologies for determining metric tons per acre for each of the carbon pools included in the Offset Project Data Report.
21. *A modeling plan, following the requirements and methods in Appendix B, Section B.3.
22. *A diagram of the final baseline incorporating all required carbon stocks.
23. *A summary of the inventory of carbon stocks for each carbon pool.
24. *A summary of inventory confidence statistics.
25. *A description and estimate of the Forest Project's baseline onsite carbon stocks. Baseline onsite carbon stocks must be portrayed in a graph depicting time in the x-axis and metric tons CO_2-equivalent in the y-axis. The graph should be supported with written characterizations that explain any annual changes in baseline carbon stocks over time.
26. *An estimate of carbon that will be stored long-term in harvested wood products in the baseline.
27. *Calculation of the offset project's reversal risk rating and contribution to the Forest Buffer Account.

9.1.1.2 Reforestation Projects

In addition to the information in Section 9.1.1.1, the following information must be provided for Reforestation projects:

1. An explanation of how the Project Lands, at the time of offset project commencement, meets the eligibility requirements of a) less than 10 percent tree canopy cover for a

minimum of 10 years; or b) subject to a significant disturbance that has removed at least 20 percent of the land's above-ground live biomass. The explanation should include why the forest was out of forest cover or a description of the disturbance if a natural significant disturbance occurred.

2. For a Reforestation Project that occurs on land that has undergone a recent Significant Disturbance, indicate the eligibility scenario pertaining to the project site as identified in Appendix E, or a description of how the Forest Project occurs on a type of land for which the Forest Owner has not historically engaged in or allowed timber harvesting.
3. A qualitative characterization of baseline conditions, including an assessment of the likely vegetative conditions and activities that would have occurred in the absence of the project, taking into consideration any laws, statutes, regulations, or other legal mandates that would encourage or require reforestation on the Project Area. The qualitative assessment shall include an assessment of the commercial value of trees within the project area over the next 30 years.
4. List any laws, statutes, regulations or other legal mandates that would encourage or require reforestation on the project area.

9.1.1.3 Improved Forest Management Projects on Private Lands

In addition to the information in Section 9.1.1.1, the following information must be provided for Improved Forest Management projects on private lands:

1. Documentation that the Project Area has greater than 10 percent tree canopy cover.
2. A determination of how the Forest Project's initial standing live carbon stocks compare to Common Practice, as required in Section 6.2.1.
3. If the Forest Project's initial standing live carbon stocks are below Common Practice, a determination of the "High Stocking Reference" for the Project Area. To determine the High Stocking Reference, changes in the Project Area's live-tree carbon stocks over the preceding 10 years must be documented.
    a. Include an affidavit testifying that the inventory depicted over the past 10 years is reasonably accurate.
    b. Include a summary of volume harvested over the past 10 years.
4. Documentation of any and all legal constraints affecting forest management activities on the Project Area. The documentation of legal constraints must include:
    a. A description of each constraint (refer to Section 6.2.1.2).
    b. A narrative that describes the effect of the constraint on forest management.
    c. A description of the modeling techniques used to simulate the effects of the constraint.
5. A demonstration that the growth and harvesting regime assumed for the baseline is financially feasible following the requirements of Section 6.2.1.3.

9.1.1.4 Improved Forest Management Projects on Public Lands

In addition to the information in Section 9.1.1.1, the following information must be provided for Improved Forest Management projects on public lands:

1. Documentation demonstrating that the offset project takes place on land that has greater than 10 percent tree canopy cover.
2. A projection of future changes to Project Area forest carbon stocks by extrapolating from historical trends; and anticipating how current and future public policy will affect onsite carbon stocks per the requirements of Section 6.2.2.

3. An explanation of how current and future public policy will affect onsite carbon stocks and how, the baseline modeling incorporates constraints imposed by all applicable statutes, regulations, policies, plans and Activity-Based Funding.

9.1.1.5 Avoided Conversion Projects

In addition to the information in Section 9.1.1.1, the following information must be provided for Avoided Conversion projects:

1. Documentation demonstrating the planned or completed dedicating of the land in the Project Area to continuous forest cover through a Qualified Conservation Easement or transfer to public ownership.
2. Documentation demonstrating that the type of anticipated land use conversion is legally permissible per the requirements of Section 3.1.1.3.
3. A description of how the Project Area was determined, following the requirements in Section 4.
4. A full copy of the appraisal that was prepared for the Project Area per the requirements of Section 3.2.1.3.
5. A description of the highest value alternative land use identified in the appraisal.
6. An estimate the rate of conversion and removal of onsite carbon stocks per the requirements in Section 6.3.1.
7. A comparison of the fair market value of the anticipated alternative land use for the Project Area with the value of the current forested land use, and the calculation of an appropriate uncertainty discount (following the requirements in Section 6.3.1).
8. Where the anticipated alternative land use is commercial, residential or agricultural use, indicate the maximum slope of the project area.
9. Where the anticipated alternative land use is mining, describe the extent of mineral resources existing in the Project Area.
10. Where the anticipated alternative land use is commercial, residential or recreational use, indicate:
    a. The proximity of the Project Area to metropolitan areas;
    b. The proximity of the Project Area to grocery and fuel services and accessibility of those services;
    c. Population growth (people per year) within 180 miles of the Project Area.

9.2 Offset Project Data Report

Offset Project Operators or Authorized Project Designees must submit an Offset Project Data Report each year according to the reporting schedule in the Regulation. The listing information in Section 9.1.1 must be included in the initial Offset Project Data Report, and is subject to verifier review during the initial verification. All Offset Project Data Reports must include the information in section 9.2.1.

9.2.1 Annual Reporting

An Offset Project Data Report must be prepared for each reporting period during the Project Life. Offset Project Data Reports must be provided to verification bodies whenever a Forest Project undergoes verification. Offset Project Data Reports must contain an annual update of the project's forest carbon inventory (Section 8.2). Each report must also contain the following information. Reforestation Projects, as qualified in Section 6.1, can defer the items that are marked with an asterisk until submitting the offset project data report that will undergo the second verification.

1. Offset project name.
2. Offset project contact information, including name, phone number, address, and email address for:
    a. Offset Project Operator
    b. Authorized Project Designee (if applicable);
3. Reporting Period.
4. A statement as to whether the Forest Project and associated Project Lands have met and been in compliance with all local, state, or federal regulatory requirements during the reporting period. If not, an explanation of the non-compliance must be provided.
5. A statement as to whether all the information submitted for project Listing is still accurate. If not provided updates to the relevant listing information.
6. An updated estimate of the reporting period's carbon stocks in all required carbon pools.
7. *The appropriate confidence deduction for the forest carbon inventory following the requirements and methods in Appendix A, Section A.4)
8. *An explanation of any decrease over any 10-year consecutive period in the standing live carbon pool.
9. Any changes in the status of the Forest Owner including, if applicable per Section 3.8.1, the acquisition of new forest landholdings.
10. A description of how the project meets (or will meet) the definition of "Natural Forest Management" (refer to Section 3.8.2), including progress on criteria that have not been fully met in previous years.
11. *An estimate of reporting-year harvest volumes and associated carbon in harvested wood products.
12. *Estimated mill efficiency, as determined following the method in Appendix C, Section C.2.
13. The baseline carbon stock estimates for all required carbon pools for the reporting period, as determined following the requirements in Section 0 and approved at the time of the project's registration.
14. An estimate of Secondary Effects, following calculation steps and/or factors provided in Section 0 and approved at the time of the offset project listing.
15. The uncertainty discount for avoided conversion projects, as determined following the requirements of Section 6.3 and approved at offset project listing. (After the initial verification, the uncertainty discount does not change.)
16. A calculation of total net GHG reductions and GHG removal enhancements (QR_y) for the reporting period, following the requirements in Section 0.
17. If a reversal has occurred during the previous reporting period, the report must include a written description and explanation of the reversal, whether the reversal has been classified as intentional or unintentional, and the status of compensation for the reversal.
18. *The offset project's reversal risk rating, as determined following the requirements in Section 7 and Appendix D.
19. *A calculation of the offset project's Forest Buffer Account contribution.
20. For the initial Offset Project Data Report: Projections of baseline and actual harvesting volumes from the Project Area over 100 years.

9.2.2 Additional Reporting for Verification Years

Forest Projects must be verified at least every six years. If verification is less frequent than annual, Offset Project Data Reports must include the following additional information on aggregated GHG emission reductions or removal enhancements since the last verification:

1. Annual estimates of carbon stocks for all required carbon pools reported during each year since the last verification.
2. Confidence deduction for the forest carbon inventory applied for each year since the last verification for the project, if applicable.
3. Baseline carbon stock estimates for all required carbon pools reported during each year since the last verification.
4. Estimate of Secondary Effects reported during each year since the last verification.
5. If a reversal has occurred during the previous six years, the report must provide a written description and explanation of the reversal, whether the reversal has been classified as intentional or unintentional, and the status of compensation for the reversal.
6. Calculation of the offset project's Forest Buffer Account contribution for each year since the last verification.
7. Calculation of total net GHG reductions and GHG removal enhancements (QR_y) reported for each reporting period since the last verification.

9.3 Reporting and Verification Cycle

Upon completion of a reporting period, the Offset Project Operator or Authorized Project Designee must annually submit an Offset Project Data Report according to the schedule specified in the Regulation for each reporting period. Reporting periods are defined in the Regulation. Offset Project Data Reports must be verified (including a site visit) by an ARB-accredited verification body according to the schedule and requirements in the Regulation and Section 10.

A Forest Project is considered automatically terminated (see Section 3.4) if the Offset Project Operator or Authorized Project Designee chooses not to report data and undergo verification at required intervals.

Reforestation Projects for which an initial inventory is deferred are not eligible to receive ARB or registry offset credits until after the second verification.

10 Verification

10.1 Regulatory Verification Requirements

Offset Project Data Reports must be verified in accordance with the regulatory verification requirements in Subarticle 13 of the Regulation and this protocol. Failure to conform to any requirements in this protocol or the Regulation, as applicable, will result in an adverse verification statement. Forest Projects are not eligible to receive a qualified positive offset verification statement.

10.2 Additional Verification Requirements

In addition to the offset project verification requirements in the Regulation, verification of Offset Project Data Reports for Forest Projects must include the following:

10.2.1 Initial Verification

During the initial full verification, the following is required:

1. A detailed review of all required Listing Information during the initial verification.
    a. Include a thorough review of documentation and maps to verify the acreage of the Project Area enrolled in a Forest Project.

10.2.2 Full Verification

During every full verification, including the initial verification, the following is required of the offset verifier:

1. A detailed review of the forest carbon inventory, including:
    a. Inventory methodology and sampling design;
    b. Inventory update processes;
    c. Measurement of sample plots and sample plot locations;
    d. Lifetime and updating of sample plots, as applicable;
    e. Stratification methods, if applicable;
    f. Biomass equations and calculations;
    g. Incorporation of growth and harvest modeling and data;
    h. Documentation of inventory methods and procedures, including procedures for data quality assurance and quality control.
2. Identification and re-measurement of a selection of sample plots, along with a comparison with inventory data to have reasonable assurance that sample plots are measured accurately using the methods required in this section.

    The following paragraphs use specific terms that may not always have the same meanings in varying contexts. For the purposes of this verification the following terms and definitions apply:

- Stand: An individual unit or polygon that is relatively homogeneous in terms of the carbon stocking within its borders. For live and dead trees, the determination of stand boundaries is usually based on forest vegetation attributes, such as species, size (age), and density characteristics. For soils, the determination of soil stand boundaries is made on similar soil types.
- Stratum: A group of stands that contain a similar attribute, such as vegetation or soils attributes.
- Strata: Plural of stratum. The set of different groupings for a specific attribute, such as vegetation or soil.

The offset verifier will sample plots consistent with the objectives of a random, risk-based and efficient approach. In doing so, the offset verifier may weight the probability of selecting strata and plots based on appropriate criteria such as carbon stocking, access difficulty, and vegetation heterogeneity. Verifiers may choose to sample project plots within strata with a cluster design. The selection of a stratum may use probability proportional to carbon stocks or probability proportional to error risk.

The verification procedures described below must be applied independently for each applicable carbon pool/applicable combination of pools that is included in the Offset Project Boundary:

- Standing live and dead trees;
- Soil;
- Lying dead wood; and
- Shrubs and herbaceous understory.

Sequential statistical methods are used to minimize the verification effort when verification and project sample data agree. Sequential approaches have stopping rules rather than fixed sample sizes. With each successive plot, or series of plots, analyzed by the offset verifier, the stopping rules indicate to the offset verifier a) to continue to the next plot(s) since the results do not indicate either a bias or an agreement and further testing is required, b) stop as the testing indicates a bias, or c) stop as the testing indicates agreement. When a stopping rule is met then the result is evaluated. Verification of sample plots is successful after a minimum number of successive plots in a sequence indicate agreement. Where the stopping rules indicate the presence of a bias, additional verification plots may be collected after that time if it is felt that random chance may have caused the test to fail and a convergence towards agreement is expected with additional samples. For effective application of the sequential statistics in the field, the determination of when the stopping rule is met is determined at the end of each sampling day, which will include the full set of plots measured in that day.

Stands of a given stratum must be independently selected using a random selection design. Plots, or clusters, must be independently selected within a stand using a random or systematic design. No more than 6 plots or clusters can be assigned to a stand, unless the groups of plots required for verification exceed the number of stands that exist for the offset project. If the offset project is not stratified for each applicable pool, the offset verifier shall allocate the plots or clusters on a randomized basis. If the offset verifier uses a cluster design, the mean of the cluster accounts for one observation (plot). Plots may be measured and assessed one at a time or in reasonable batches that correspond to logistical realities such as crew-days of effort. Verification sampling may be conducted using clustering or systematic approaches to facilitate efficiency.

When the project area has been stratified for the purposes of estimating the Forest Project's inventory based on common characteristics for each carbon pool, the offset verifier shall select three strata for each applicable carbon pool based on the offset verifier's evaluation of risk. Consideration of risk should be based on the overall importance of a given stratum to the project's total stocks and the presumption that any given stratum is inaccurately measured. The selection of stands to verify within a given stratum must be random. The minimum number of sample plots varies by project size and number of strata verified. (Table 10.1).

Table 10.1. Minimum number of sample plots in sequence, as a function of project size.

Test	Number of Strata Verified	Project Acres				
		<100	100 - 500	501 - 5,000	5,000 - 10,000	> 10,000
Paired/Unpaired	3	2	3	4	5	6
	2	4	6	8	10	12
	1	8	12	16	20	24

There are two possible statistical procedures that can be applied to the stratum-level verifications. A paired test can be applied when plot locations can be found and it is statistically appropriate (i.e. plot measurements can be replicated) to use a paired test. An unpaired test can be applied when plots cannot be relocated. The range of acceptable error (δ, delta) is fixed at 10 percent.

Assigning Risk to Strata: The offset verifier must determine for each applicable pool or combination of pools if the Offset Project Operator or Authorized Project Designee has stratified the project area into strata that reflect common characteristics that influence carbon stocks. The offset verifier may presume risk exists in the highest stocked strata, strata that are unique or difficult to access due to topographical, vegetative, or other physical barrier, strata that represent a large portion of the project's inventory due to the area they represent, or any other risk perceived by the offset verifier. The determination of risk must be applied to the stratum as a unit and not individual stands of a given stratum.

Selecting Strata based on Risk: Based on the assessment of risk, the offset verifier will query, or request that the Offset Project Operator or Authorized Project Designee query, the set of stands that are associated with the strata selected. The queried stands must have an identifier which can be based on the Offset Project Operator or Authorized Project Designee's identification convention or one assigned by the offset verifier. Three strata must be selected, or the maximum number of strata stratified by the Offset Project Operator or Authorized Project Designee for each pool. Table 10.2 displays an example of ordered strata for standing live and dead trees selected by stratum with random numbers assignments.

Table 10.2. Stands selected by vegetation strata and risk class with random number assignments.

Stand Number	Stratum (from Forest Owner or Verifier)	Risk Class	Order of Random Selection
2	Dense Intermediate Conifers	High Stocking	5
3	Dense Intermediate Conifers	High Stocking	3
4	Dense Intermediate Conifers	High Stocking	1
8	Dense Intermediate Conifers	High Stocking	8
9	Dense Intermediate Conifers	High Stocking	2
10	Dense Intermediate Conifers	High Stocking	1
15	Dense Intermediate Conifers	High Stocking	4
18	Dense Intermediate Conifers	High Stocking	7
Stand Number	**Stratum (from Forest Owner or Verifier)**	**Risk Class**	**Order of Random Selection**
8	Dense Mature Conifers	High Stocking	4
9	Dense Mature Conifers	High Stocking	3
10	Dense Mature Conifers	High Stocking	5
15	Dense Mature Conifers	High Stocking	2
18	Dense Mature Conifers	High Stocking	1
Stand Number	**Stratum (from Forest Owner or Verifier)**	**Risk Class**	**Order of Random Selection**
13	Medium Dense Mature Riparian	Difficult Access	2
14	Medium Dense Mature Riparian	Difficult Access	1
17	Medium Dense Mature Riparian	Difficult Access	3

Planning and Implementing Field Verification Sampling: The selected stands should be mapped and labeled with the random number to assist in developing a strategy to perform field sampling activities. Up to 6 plots or clusters may be re-measured in a stand (if plots are monumented) or installed (if plots are not monumented) in each stand. If the project area has not been stratified or there are less than 3 strata, the offset verifier shall locate the plots or clusters using a random process of their own design. For efficiency, it is acceptable for the offset verifier to relocate to a new area at the beginning of a day without having completed all the plots in the previous day.

Determination if the Stopping Rules have been met: The offset verifier must determine if the stopping rules have been met for each stratum after the measurement of each plot, unless the offset verifier determines it is appropriate to defer the determination until no later than the end of each day of sampling. The offset verifier must conduct the appropriate calculation for a paired or unpaired test. It is required that the offset verifier apply the random order selection in the sampling process. For efficiency purposes, the offset verifier may skip the random order on a temporal basis as long as the sequential analysis includes the ordered set of stands. This may provide significant efficiencies when selected stands and/or plots are in close geographic proximity and it is hypothesized that the stopping rules will require the full number of plots. An example is displayed in Table 10.3.

Table 10.3. The table displays a sampling schedule planned by the offset verifier and the verification results. In this example, the sequential sampling is conditionally satisfied

after Day 3 but requires the full set of randomly selected stands to be sampled up to the point of satisfying the sequential statistics, which is met after sampling Stand 3 on Day 4.

Stand	Stratum (from Forest Owner)	Risk Class	Order of Random Selection	Sampling Schedule (Planned)	Verification Effort	Verification Results
4	Dense Intermediate Conifers	High Stocking	1	Day 3	Day 1	Inconclusive. Stand 9 sampled. Sequential sampling criteria not satisfied - More plots are needed
9	Dense Intermediate Conifers	High Stocking	2	Day 1	Day 2	Inconclusive. Stand 15 sampled. Sequential sampling criteria not satisfied - More plots are needed
3	Dense Intermediate Conifers	High Stocking	3	Day 4	Day 3	Inconclusive. Stand 4 sampled. Sequential sampling criteria satisfied but stand order must be satisfied. Stand 3 must be sampled.
15	Dense Intermediate Conifers	High Stocking	4	Day 2	Day 4	Conclusive. Stand 3 sampled. Sequential sampling criteria is met and adherence to random selection is maintained
2	Dense Intermediate Conifers	High Stocking	5	Day 6	Further Verification Effort not Necessary	
10	Dense Intermediate Conifers	High Stocking	6	Day 5		
18	Dense Intermediate Conifers	High Stocking	7	Day 7		
8	Dense Intermediate Conifers	High Stocking	8	Day 8		

Paired Plots: The statistical test is based on a comparison of the offset verifier's measurements of plots within a selected stratum, calculated as CO_2-equivalent compared to the Offset Project Operator's or Authorized Project Designee's measurements of plots, which may include any adjustments for growth. The offset verifier must use α=0.05 and β=0.20 to control for error. The null hypothesis (H_0) is that the verification and project plots are equal.

1) Sample and measure at least the minimum number of plots required in Table 10.1.
2) If $n \geq ((Z_\alpha + Z_\beta)^2 \times S_n^2) / D^2$ then stop and evaluate. Otherwise take another sample.

n = Number of verification plots measured,
Z_α = α/2% N(0,1) = 1.645,
Z_β = β/2% N(0,1) = 0.8416,
S_n^2 = sample variance of the differences,
D = δ × project average estimate.

3) If stopped, then evaluate.

   If $\bar{X}_N \leq K$ then accept H_0,
   If $\bar{X}_N > K$ then reject H_0.

   $\bar{X}_N$= sample mean of the differences,
   N = total number of plots measured,

   $K = (Z_\alpha \times D) / (Z_\alpha + Z_\beta)$.

4) If H_0 was rejected then additional samples may be taken as long as the offset verifier is of the opinion that there is a chance that H_0 may be accepted based on the variability and trend observed.

Unpaired Plots: The statistical test is based on comparing the average CO_2-e estimates for each stratum from the verifier plots to the Offset Project Operator's or Authorized Project Designee's plots.

The offset verifier must use α=0.05 to control for error; the β is not specified because the method is constructing a confidence interval not a test. The null hypothesis (H_0) is that the verification and stratum averages are equal. The following procedure is appropriate for the unpaired test.

1) Sample and measure at least the minimum number of plots required in Table 10.1. Calculate n as the sum of the number of plots from both the stratum and the verification.
2) Calculate the following:

   $T_n = \bar{X}_P - \bar{X}_n$ where,
   $\bar{X}_P$ = stratum mean,
   $\bar{X}_n$ = verification mean after sample n.
   S_n^2 = sample variance of the verification plots,
   S_P^2 = sample variance of the stratum plots,
   D = δ × stratum average estimate.
   a = the percentile from a standard normal distribution for one half of alpha; is equal to 1.96 for α=0.05

3) If $n \geq (a^2/D^2) \times (S_n^2 + S_P^2)$ then stop and evaluate. (Note: $n = n = n_P + n_V$). Otherwise take another sample.
4) If stopped, then evaluate. Construct a confidence interval $T_n \pm D$.

   If the confidence interval includes zero then accept H_0,
   Otherwise reject H_0.

5) If H_0 was rejected then additional samples may be taken until as long as the verifier is of the opinion that there is a chance that H_0 may be accepted based on the variability and trend observed.

If the stopping rule in step (3) above cannot be attained within 100 plots then apply a standard unpaired t-test comparison using alpha of 0.05 and beta of 0.80.

3. Application of appropriate confidence deductions, if applicable.
4. Review reversal risk rating calculation.
5. Review of conformance with natural forest management and sustainable harvesting requirements.

10.2.3 Less-Intensive Verification

Less intensive verification refers to offset verification services that may be provided in interim years between full verifications. In the case of Forest Projects, full verification is required once every six years. Less intensive verification services may be provided in interim years between full verification at the discretion of the Offset Project Operator or Authorized Project Designee, subject to the concurrence of the accredited verification body that conducted the last full verification. Less intensive verification is not allowed if (1) there have been significant changes in methodologies or updates to the forest carbon inventory program, or (2) there has been a change in verification body since the previous verification.

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. A site visit is not required. This level of verification may only be used if the verification team can provide findings with a reasonable level of assurance.

During less intensive verification of Forest Projects, the verification team must:

- Conduct data checks and carefully review data and calculations contained within the Offset Project Data Report, and
- At a minimum, review documentation supporting the data and calculations in the Offset Project Data Report, including the data used to update the forest carbon inventory and any new sample plot measurements, updates in growth and yield models, timber harvest plans and other regulatory documentation related to timber harvest, documentation of timber sales.

10.2.4 Verification of Multiple Reporting Years

If verification is less frequently than annual, the verification team must separately review and evaluate each reporting period of reported data specified in Section 9.2.2.

1. Each reporting period of quantified GHG reductions or GHG removal enhancements (QR_y) is separately evaluated for offset material misstatement.

10.2.5 Verification Team

Each verification team must include the following:

1. At least one Professional Forester that takes an active role in reviewing the forest carbon inventory program and conducting the site visit.
2. At least one individual with demonstrated competence in forest biometrics through:

   a. A master's degree in statistics or forest biometrics, or another closely related science that includes 12 semester or 16 quarter hours of forest biometrics, sampling design and/or statistics coursework; or
   b. University coursework that includes 12 semester or 16 quarter hours of forest biometrics, sampling design and/or statistics coursework, and at least two years of experience sampling, developing, implementing and analyzing forest biomass or carbon inventories
3. At least one individual with demonstrated knowledge of and competence in the use of forest growth and yield models, and demonstrated experience working with the model used in the forest carbon inventory being verified. Such experience should include university or other professional coursework, and/or project experience demonstrating competency in the use of the model.
4. An ARB-accredited Forest Offset Project Specialist.

An explanation demonstrating that the verification team includes individuals with the required experience and expertise must be included in the Notice of Verification Services submittal. The required experience and expertise may be demonstrated by a single individual, or by a combination of individuals.

10.2.6 Minimum Required Verification Schedule

Except as allowed for the second verification of Reforestation Projects, ARB requires that an ARB-accredited third-party verification body review and assess all reported data and information for a Forest Project and conduct a site visit at least once every six years. Verification is also required anytime new confidence deductions and/or reversal risk ratings are established.

For Reforestation Projects, the second verification may be deferred up to 12 years at the discretion of the Offset Project Operator or Authorized Project Designee.

11 Glossary of Terms[8]

Above-Ground Live Biomass	The total mass of biomass in live trees including the stem, branches, and leaves or needles, brush and other woody live plants above ground.
Activity-Based Funding	The budget line items that are dedicated to agency accomplishments in vegetation management, including pre-commercial thinning, commercial thinning, harvest, hazard tree removal, hazardous fuel reductions, and other management activities designed to achieve forest sustainability health objectives.
Additional	Additional is defined in the Regulation. Under this protocol, GHG reductions or removals from Forest Projects are demonstrated to be addition when they pass a legal requirement test and a performance test, as described in Section 3.1, and by achieving GHG reductions and removals quantified against an approved baseline, determined according to the requirements in Section 0.
Allometric Equation	An equation that utilizes the genotypical relationship among tree components to estimate characteristics of one tree component from another. Allometric equations allow the below ground root volume to be estimated using the above-ground bole volume.
Assessment Area	A distinct forest community within geographically identified ecoregions that consists of common regulatory and political boundaries that affect forest management. The size of an Assessment Area is determined by efforts to achieve optimal statistical confidence across multiple scales using U.S. Forest Service Forest Inventory and Analysis Program (FIA) plots for biomass. Maps of the Assessment Areas and the associated data may be found on ARB's website.
Avoided Conversion Project	A type of Forest Project consisting of specific actions that prevent the conversion of privately owned forestland to a non-forest land use by dedicating the land to continuous forest cover through a conservation easement or transfer to public ownership.

[8] For terms not defined in this section, the definitions in the Regulation apply.

Best Management Practices	Management practices determined by a state or designated planning agency to be the most effective and practicable means (including technological, economic, and institutional considerations) of controlling point and nonpoint source pollutants at levels compatible with environmental quality goals.
Biological Emissions	For the purposes of the Forest Offset Protocol, biological emissions are GHG emissions that are released directly from forest biomass, both live and dead, including forest soils. For Forest Projects, biological emissions are deemed to occur when the reported tonnage of onsite carbon stocks, relative to baseline levels, declines from one year to the next.
Biomass	Biomass is defined in the Regulation.
Bole	A trunk or main stem of a tree.
Broadcast Fertilization	A fertilizer application technique where fertilizer is spread across the soil surface.
Carbon Pool	A greenhouse gas reservoir.
Common Practice	The average stocks of the standing live carbon pool from within the Forest Project's Assessment Area, derived from FIA plots on all private lands within the defined Assessment Area.
Even-Aged Management	Management where the trees in individual forest stands have only small differences in their ages (a single age class). By convention, the spread of ages does not differ by more than 20 percent of the intended rotation.
FIA	USDA Forest Service Forest Inventory and Analysis program. FIA is managed by the Research and Development organization within the USDA Forest Service in cooperation with State and Private Forestry and National Forest Systems. FIA has been in operation under various names (Forest Survey, Forest Inventory and Analysis) for 70 years.
Forest Buffer Account	Forest Buffer Account is defined in the Regulation as a holding account for Forest Project ARB offset credits administered by ARB. It is used as a general insurance mechanism against unintentional reversals for all forest offset projects listed under a Compliance Offset Protocol.

Forest Management	The commercial or noncommercial growing and harvesting of forests.
Forest Owner	A Forest Owner is defined in the Regulation as the owner of any interest in the real (as opposed to personal) property involved in a forest offset project. 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.
Forest Project	A planned set of activities designed to increase removals of CO_2 from the atmosphere, or reduce or prevent emissions of CO_2 to the atmosphere, through increasing and/or conserving forest carbon stocks.
Forestland	Land that supports, or can support, at least 10 percent tree canopy cover and that allows for management of one or more forest resources, including timber, fish and wildlife, biodiversity, water quality, recreation, aesthetics and other public benefits.
GHG Removal Enhancement	GHG removal enhancement is defined in the Regulation. GHG removal enhancements are calculated as gains in carbon stocks over time relative to a Forest Project's baseline.
Greenhouse Gas (GHG) Reservoir	Greenhouse Gas Reservoir is defined in the Regulation. For Forest Projects, GHG reservoirs may include above-ground or below-ground biomass or harvested wood products, among others.
Improved Forest Management Project	A type of Forest Project involving management activities that increase carbon stocks on forested land relative to baseline levels of carbon stocks.
Listed	A Forest Project is considered "listed" when an the Offset Project Operator or Authorized Project Designee is registered with ARB or an approved offset project registry, submits all required documentation for project listing in the Regulation and this protocol, and the project has been approved by ARB or an approved offset project registry for listing.
Litter	Any piece(s) of dead woody material from a tree,

	e.g. dead boles, limbs, and large root masses, on the ground in forest stands that is smaller than material identified as lying dead wood.
Lying Dead Wood	Any piece(s) of dead woody material from a tree, e.g. dead boles, limbs, and large root masses, on the ground in forest stands. Lying dead wood is all dead tree material with a minimum average diameter of 5" and a minimum length of 8'. Anything not meeting the measurement criteria for lying dead wood will be considered litter. Stumps are not considered lying dead wood.
Metric ton (MT) or "ton"	A common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1023 short tons.
Native Forest	For the purposes of this protocol native forests shall be defined as those occurring naturally in an area, as neither a direct nor indirect consequence of human activity post-dating European settlement.
Natural Forest Management	Forest management practices that promote and maintain native forests comprised of multiple ages and mixed native species at multiple landscape scales. The application of this definition, its principles, detailed definition, and implementation are discussed further in the Section 3.8.2.
Non-Forest Cover	Land with a tree canopy cover of less than 10 percent.
Non-Forest Land Use	An area managed for residential, commercial, or agricultural uses other than for the production of timber and other forest products, or for the maintenance of woody vegetation for such indirect benefits as protection of catchment areas, wildlife habitat, or recreation.
Non-Harvest Disturbance	Reduction in forest cover that is not a direct result of harvest, such as wildfire and insect disturbances.
Onsite Carbon Stocks	Carbon Stock as defined in the Regulation means "the quantity of carbon contained in an identified GHG reservoir." For Forest Projects onsite carbon stocks include the carbon stocks in the required carbon pools indicated in Table A.1 within the Project Area.
Primary Effect	The Forest Project's intended changes in carbon stocks, GHG emissions, or GHG removals.

Professional Forester	A professional engaged in the science and profession of forestry. For forest projects that occur in a jurisdiction that has professional forester licensing laws and regulations, a Professional Forester must be credentialed in that jurisdiction. Where a jurisdiction does not have a professional forester law or regulation, then a Professional Forester is defined as either having the Certified Forester credentials managed by the Society of American Foresters, or other valid professional forester license or credential approved by a government agency in a different jurisdiction.
Project Area	The area inscribed by the geographic boundaries of a Forest Project, as defined following the requirements in Section 4 of this protocol. Also, the property associated with this area.
Project Life	Refers to the duration of a Forest Project and its associated monitoring and verification activities, as defined in Section 3.4.
Public Lands	Lands that are owned by a public governmental body such as a municipality, county, state, or country.
Qualified Conservation Easement	A qualified conservation easement must explicitly refer to the requirements of the regulation and this protocol and apply to current and all subsequent Forest Owners for the full duration of the Forest Project's minimum time commitment, as defined in Section 3.4 of this protocol.
Reforestation Project	A type of Forest Project involving the restoration of tree cover on land that currently has no, or minimal, tree cover.
Reversal	A reversal as defined in the Regulation. Under this protocol, a reversal is deemed to have occurred if the quantified GHG reductions and removal enhancements in a given year are negative and offset credits were issued to the Forest Project in any previous year, regardless of the cause of the decrease.
Secondary Effects	Unintended changes in carbon stocks, GHG emissions, or GHG removals caused by the Forest Project.
Significant Disturbance	Any natural impact that results in a loss of at least 20 percent of the above-ground live biomass that is not the result of intentional or grossly negligent acts of the Forest Owner.

Standing Dead Carbon Stocks	The carbon in standing dead trees. Standing dead trees include the stem, branches, roots, or section thereof, regardless of species, with a minimum diameter at breast height of five inches and a minimum height of 15 feet. Stumps are not considered standing dead stocks.
Standing Live Carbon Stocks	The carbon in the live tree biomass. Live trees include the stem, branches, roots, and leaves or needles of all live biomass, regardless of species, with a minimum diameter at breast height of five inches and a minimum height of 15 feet.
Stocks (or Carbon Stocks)	The quantity of carbon contained in an identified GHG reservoir (or carbon pool).
Submitted	A Forest Project is "submitted" when all of the appropriate forms have been uploaded and submitted.
Tree	A woody perennial plant, typically large and with a well-defined stem or stems carrying a more or less definite crown with the capacity to attain a minimum diameter at breast height of 5 inches and a minimum height of 15 feet with no branches within 3 feet from the ground at maturity.
Unintentional Reversal	An unintentional reversal as defined in the Regulation is any reversal not due to the Forest Owner's negligence, gross negligence or willful intent, including wildfires or disease that are not the result of the Forest Owner's negligence, gross negligence or willful intent.
Uneven-Aged Management	Management that leads to forest stand conditions where the trees differ markedly in their ages, with trees of three or more distinct age classes either mixed or in small groups.

Appendix A Developing an Inventory of Forest Project Carbon Stocks

Quantification Methodology

This appendix provides requirements for quantifying a Forest Project's forest carbon stocks. It explains how to identify the required forest carbon pools measured in a Forest Project, as well as the steps necessary for quantifying the existing carbon stocks in the selected pools within the Project Area. Carbon inventory information serves two purposes:

1. It is used as the basis for modeling and estimating carbon stocks in a Forest Project's baseline (following the requirements of Section 0).
2. It is used to quantify actual carbon stocks during the course of a project.

This appendix explains the essential steps and requirements for completing a carbon inventory for all required onsite carbon pools associated with a Forest Project.

A.1 Provide Background Information on Forest Area

To begin the inventory process, develop a general description of the activities and land use patterns that influence carbon stocks in the Project Area, including all the information required in Section 9.1.1.1. This information will help inform the initial design of the forest inventory, as well as the estimations of carbon stocks. This information will be reviewed during verification.

A.2 Measure Carbon Pools in the Project Area

Forest carbon pools are broadly grouped into the following categories:

1. Living biomass
2. Onsite dead biomass
3. Soil

Values for some of these categories of carbon will be determined through direct sampling. Table A.1 indicates the categories with their associated carbon pools and identifies which pools must be quantified for all offset projects versus those are excluded depending on the project. It also shows how the value for the pool is determined.

Table A.1. Requirements of carbon pool categories and determination of value for pool

Category	Carbon Pool	Improved Forest Management	Reforestation	Avoided Conversion	Determination of Value
Living biomass	Standing Live	Required	Required*	Required	Sampled in Project
	Shrubs and Herbaceous Understory	Excluded	Required	Excluded	Sampled in Project
Onsite dead biomass	Standing Dead	Required	Required	Required	Sampled in Project
Soil	Soil**	Required/ Excluded**	Required/ Excluded**	Required/ Excluded**	Sampled in project

* Pre-existing trees must be distinguished from planted trees. Since pre-existing and new trees are easy to distinguish for several decades after tree planting, pre-existing trees do not need to be inventoried until the offset project first seeks verification of GHG reductions and GHG removal enhancements.
** Soil carbon is not anticipated to change significantly as a result of most Forest Project activities. Soil carbon is excluded except when specified in Section 5.

A.3 Developing Onsite Forest Carbon Inventories

To develop estimates of carbon stocks in the carbon pools identified in Table A.1, a forest inventory must first be conducted. Standard forest inventories require the establishment of sample plots and provide inventory estimates in terms of cubic or board foot volume. These measurements are based on the species, trunk or bole diameter, form and height of the tree.

Each Offset Project Operator or Authorized Project Designee must develop and document a forest carbon inventory methodology. The inventory method must be capable of quantifying carbon stocks for required carbon pools to a high degree of accuracy. A complete inventory methodology must include:

1. A description of the Offset Project Boundary, including a list of all carbon pools included in the Offset Project Boundary.
2. For each carbon pool, include a detailed description of the inventory sampling methodology used to quantify that carbon pool, with references clearly documented. This documentation must include:
    a. Standard procedures for the collecting of field measurements. These procedures must be detailed enough so that any qualified forester would be able to accurately repeat the previous measurements. These procedures must include a description of the types of sample plots, location of plots, and frequency for updating or replacing sample plots as well as the forest carbon inventory as a whole;
    b. Standard procedures for where and how to measure parameters used in biomass calculations such as dbh and height (including for irregular trees), how to classify dead wood, and for any other aspects of sampling where a consistent method needs to be documented; and
    c. Stratification rules (pre and post sampling), if applicable, that include a map of vegetation strata, results of stratification (area by strata), tools for application

(such as GIS, aerial photos), and a discussion of how boundaries were determined.

3. Documentation of all analytic methods and biomass equations used to translate field measurements into volume or biomass carbon estimates;
4. A documented quality assurance / quality control (QA/QC) plan including procedures for internal review to ensure that standard operating procedures are being followed. The QA/QC plan must include procedures for assessing and ensuring the quality of collection, transfer and archiving of field data; procedures for data entry and analysis, and data maintenance and archiving; and any other relevant procedures to ensure quality and consistency in the collection and maintenance of data used to compile the offset project data reports.
5. Description of data management systems and processes, including the collection, storage and analysis of inventory related data analytical methods to translate field measurements into volume and/or biomass estimates.
6. A change log documenting any changes in the inventory methods or equations used to calculate carbon stocks.
7. Standard procedures for updating the forest carbon inventory, including documented procedures to account for:
    a. Harvest;
    b. Growth;
    c. Disturbance;
    d. Incorporating new inventory and plot data, and retiring older sample plots;
    e. Modeling, as allowed under Appendix B; and
    f. Application of appropriate confidence deduction.

Inventory methods and sampling procedures, once established, must be consistent over the life of the project. Any changes to inventory methods or calculations must be documented and justified in the change log.

Allometric Equations and Biomass/Carbon Mass Estimates

The equations in this appendix and in the Forest Offset Protocol Resources section of ARB's webpage must be used for biomass and carbon mass estimations using the bole diameter and total height for live trees and sound standing dead trees. Estimates of standing dead tree (for non-sound trees) biomass must be computed in terms of cubic volume and subsequently converted to biomass/carbon mass estimates.

Sample Plots

Any plot data used for deriving the forest carbon inventory estimates must have been sampled within the last 12 years. The scheduling of plot sampling may occur in one time period or be distributed over several time periods. Either approach is acceptable so long as an inventory of the entire Project Area (its required carbon pools and corresponding sample plots) is completed within 12-year intervals.

Steps for Developing a Complete Forest Carbon Inventory

The steps that follow provide more detail on establishing and maintaining a complete inventory and estimating carbon stocks. Results must be summarized in a table when submitting required data in an Offset Project Data Report (see Section 9).

Step 1 – Developing Inventory Methodology and Sample Plots

The Offset Project Operator or Authorized Project Designee must develop and describe a methodology to sample for biomass or volume of all required carbon pools. If a pre-existing forest inventory is used to develop a forest carbon inventory, all steps here must be followed to ensure the existing inventory meets the requirements of this protocol.

Sampling methodology and measurement standards should be consistent throughout the duration of the Forest Project. If new methodologies are adopted, they must achieve an equal or greater accuracy relative to the original sampling design. All sampling methodologies and measurement standards must be statistically sound and must be approved during verification.

Stratification is not required, but it may simplify verification. Temporary flagging of plot center, as is customary to allow for check cruising, is required to ensure ongoing inventory quality and allow for offset verifiers to visit plots when verifying inventory procedures. If permanent plots are used, which are statistically efficient for stock change estimates, permanent plot monumenting must be sufficient for relocation. Plot centers should be referenced on maps, preferably with GPS coordinates. The methodologies utilized must be documented and made available for verification and public review. The design of the sampling methodology and measurement standards must incorporate the requirements in the following table. All tree species within the Project Area must be measured regardless of the merchantability of the trees.

Table A.2. Minimum required sampling criteria for estimated pools

Carbon Pool	Name of Requirement	Description of Requirement
Standing Live Carbon Stocks (above-ground portion)	Diameter (breast height) Measurements	The minimum diameter (at breast height) must be stated in the methodology, and this minimum diameter must not be greater than 5 inches (inventory must include all trees 5 inches and greater in diameter). Height must be measured as required in appropriate biomass equations.
	Measurement Tools	Description of tools used for height measurement, diameter measurement, and plot measurement.
	Measurement Standards	The methodology shall include a set of standards for tree and plot size measurements.
	Plot Layout	A description of plot layout.
	Merchantability of Trees	The methodology shall include all trees regardless of current merchantability to be included in the sampling design.
	Allometric Equation used for Estimating Biomass	The methodology must include a description of the allometric equation used to estimate the whole tree biomass (bole, branches, and leaves) from bole diameter measurements. The use of functions other than those provided in the protocol will need to be approved by ARB and the verification body.
Standing Live Carbon Stocks (below-ground portion)	Plot-level Allometric Equation used for Estimating Biomass	Apply model (Cairns, Brown, Helmer, & Baumgardner, 1997) to estimate below-ground biomass density. This model equation is based on above-ground biomass density in tons per hectare. The use of a function other than that provided in the protocol will need to be approved by ARB and the verification body.
Herbaceous Understory	Sampling Methodology	The sampling methodology prepared by Brown, Shoch, Pearson, & Delaney (2004). Alternative methodologies need to be reviewed and approved by ARB and the verification body.
Standing Dead Trees	Diameter (breast height) and top Diameter Measurements	The minimum diameter (at breast height) must be stated in the methodology, and this diameter must not be greater than 5 inches. The minimum height of standing dead trees is 15'. The method must include how volume is derived where a total height does not exist (i.e. where the tree is broken).
	Measurement Tools	Description of tools used for height, diameter and plot measurement.
	Measurement Standards	The methodology shall include a set of standards for height and diameter measurements.
	Plot Layout	A description of plot layout (may be the same layout as for live tree biomass).
	Merchantability of Trees	The methodology shall include all trees regardless of current merchantability to be including in the sampling design.

Step 2 – Estimating Carbon in Live Trees from Sample Plots

Standing live tree carbon estimates are required for all offset projects. The standing live tree estimate includes carbon in all portions of the tree, including the bole, stump, bark, branches, leaves, and roots. The Offset Project Operator or Authorized Project Designee is responsible for determining appropriate methodologies for sampling to determine standing live tree carbon stocks. The estimate of above-ground live tree biomass must be combined with the estimates of biomass from other carbon pools to determine a mean estimate of the included pools derived from sampling, along with a summary that describes the statistical confidence of the estimate.

All biomass estimates must be converted to carbon estimates. The derived estimate of biomass must be multiplied by 0.5 to calculate the mass (kg) in carbon. This product must be multiplied by 0.001 tons/kg to convert the mass to metric tons of carbon.

Approved biomass equations will be available in the Forest Offset Protocol Resources section of ARB's website.

Step 3 – Estimating Carbon Standing Dead Tree Carbon from Sample Plots

An inventory of carbon stocks in standing dead tree carbon is required for all Forest Projects. The Offset Project Operator or Authorized Project Designee must provide a sampling methodology for standing dead tree carbon as part of an overall sampling strategy (discussed in Step 1). Sound dead trees can be computed using the equations provided for standing live carbon in Step 2. The estimate of standing dead tree carbon for highly decayed trees (broken tops, missing branches, etc.), must be calculated first volumetrically and subsequently converted to biomass and carbon tons.

For those trees where volume is computed, the volume will need to be converted to biomass density by applying conversion factors based on decay class. The methodology developed must include a description of the calculation techniques used to determine biomass density by decay class. The estimate of biomass density must be computed in terms of metric tons of carbon on a per acre basis. The density factors by decay class from Harmon et al (2008) may be used to estimate density in standing dead carbon stocks.

Step 4– Estimate Carbon in Shrubs and Herbaceous Understory from Sample Plots

Any methodology developed for measuring carbon in shrubs must be reviewed during verification. The most applicable biomass estimation methods may be used, including photo series, the estimation functions from published papers, direct sampling, or combinations of approaches.

Step 5 – Estimate of Carbon Tons in Soil

Changes in total soil carbon are a challenge to measure over short timeframes, as this pool changes slowly and is usually dependent on the rate of biomass input relative to soil decomposition. The sampling methodology and protocols for deriving carbon estimates in soil must be developed as part of an overall sampling strategy (discussed in Step 2). Use the soil sampling methodology prepared by Brown, Shoch, Pearson, & Delaney (2004).

Step 6 – Sum Carbon Pools

The metric tons of carbon in each carbon pool, as derived from the preceding steps, must be entered in the following table. For the purpose of quantifying GHG reductions and GHG removal enhancements, all numbers must be converted to metric tons of CO_2-equivalent by multiplying by 3.664.

Table A.3. Summarizing Carbon Pools and Calculating Total Carbon

Carbon Pool	Source	Gross CO_2-equivalent Tons per Acre
Step 2 Live Carbon Stocks	From sampling results of trees.	
Steps 3 Standing Dead Carbon Stocks	From sampling results of standing dead biomass.	
Step 4 Shrubs and Herbaceous Understory	From sampling results of shrubs and herbaceous understory.	
Step 5 Soil	From sampling results of soil.	
Sum of CO_2-equivalent Tons from Required Pools		

A.4 Applying a Confidence Deduction

Any forest carbon inventory estimate will be subject to statistical uncertainty. Where statistical confidence is low, there is a higher risk of overestimating a project's actual carbon stocks and therefore a higher risk of over-quantifying GHG reductions and GHG removal enhancements. To help ensure that estimates of GHG reductions and GHG removal enhancements are conservative, a confidence deduction must be applied each year to the inventory of actual onsite carbon stocks. A confidence deduction is *not* applied to the forest carbon inventory when it is used to model baseline carbon stocks.

To determine the appropriate confidence deduction, perform the following:

1. Compute the standard error of the inventory estimate (based on the carbon in all carbon pools included in the forest carbon inventory).
2. Multiply the standard error by 1.645.
3. Divide the result in (2) by the total inventory estimate and multiply by 100. This establishes the sampling error (expressed as a percentage of the mean inventory estimate from field sampling) for a 90 percent confidence interval.
4. Consult Table A.5 to identify the percent confidence deduction that must be applied to the inventory estimate for the purpose of calculating GHG reductions and removals (i.e. variable CD_y in Equation 6.1 in Section 0).

Table A.4. Forest carbon inventory confidence deductions based on level of confidence in the estimate derived from field sampling.

Sampling Error (% of Inventory Estimate)	Confidence Deduction
0 to 5%	0%
5.1 to 19.9%	(Sampling Error – 5.0%) to the nearest $1/10^{th}$ percentage
20% or greater	100%

The confidence deduction must be updated each time the offset project is subject to verification, but must remain unchanged between verifications. If increased sampling over time results in a

lower confidence deduction at the time of verification, the lower deduction must be applied to inventory estimates in the most recent reporting period subject to verification at that time. ARB or registry offset credits may be issued in the most recent reporting period for any verified increase in quantified GHG reductions and GHG removal enhancements associated with the new (lower) confidence deduction. Conversely, if a loss of qualified sampling plots results in a higher confidence deduction, this higher deduction is applied to the inventory estimates in the most recent reporting period subject to verification at that time. Any resulting decrease in quantified GHG reductions and GHG removal enhancements from prior years as a result of the increased confidence deduction will be treated as an intentional reversal, and must be compensated pursuant to the Regulation.

Appendix B Modeling Carbon Stocks

Quantification Methodology

This protocol requires the use of certain empirical-based models to estimate the baseline carbon stocks and project stocks of selected carbon pools within the Project Area. These models may also be used to supplement assessments of actual changes in carbon stocks resulting from the Forest Project.

B.1 About Models and Their Eligibility for Use with Forest Projects

Empirical-based models are used for estimating existing values where direct sampling is not possible or cost-effective. They are also used to forecast the estimations derived from direct sampling into the future. Field measurements provide the basis for inferring value through the use of these models.

The models that simulate growth projections have two basic functions in the development and management of a forest project. Models project the results of direct sampling through simulated forest management activity. These models, often referred to as growth and yield simulation models, may project information regarding tree growth, harvesting, and mortality over time – values that must ultimately be converted into carbon in an additional step. Other models may combine steps and estimate tree growth and mortality, as well as changes in other carbon pools and conversions to carbon, to create estimated projections of carbon stocks over time.

Models are also used to assist in updating inventory plots so that the plots can represent a reporting year subsequent to their actual sample date. The model simulates the diameter and height increment of sampled trees for the length of time between their sampled date and the reporting year. The limit to the use of models for updating plot data is described in Appendix A.

The following growth models have been approved:

- CACTOS: California Conifer Timber Output Simulator
- CRYPTOS: Cooperative Redwood Yield and Timber Output Simulator
- FVS: Forest Vegetation Simulator
- SPS: Stand Projection System
- FPS: Forest Projection System
- FREIGHTS: Forest Resource Inventory, Growth, and Harvest Tracking System
- CRYPTOS Emulator
- FORESEE

Inventory plot data may be updated for estimating diameter and height growth by incorporating data obtained from sample plots, as in a stand table projection. To qualify for this method:

- The Project Area shall be stratified into even-age management and uneven-age management.
- Diameter increment shall be based on the average annual increment of a minimum of 20 samples of radial growth for diameter increment for each 8" DBH (diameter at breast height) class, beginning at 0 – 8" DBH for each management (even-age or uneven-age) type. The average annual increment shall be added for each year according to the plot's sample date.
- Height increment shall be based on regression curves for each management type (even-age or uneven-age) developed from height measurements from the same trees the

diameter increment data was obtained. The estimated height shall be determined using the regression estimators for the 'grown' diameters as described above.

Additional models will be allowed following approval of a state forestry authority (i.e. a state agency responsible for oversight of forests) who will acknowledge in writing that the model:

- Has been peer reviewed in a process that: 1) primarily involved reviewers with necessary technical expertise (e.g. modeling specialists in relevant fields of biology, forestry, ecology, etc.), and 2) was open and rigorous
- Is parameterized for the specific conditions of the Project Area
- Limits use to the scope for which the model was developed and evaluated
- Is clearly documented with respect to the scope of the model, assumptions, known limitations, embedded hypotheses, assessment of uncertainties, and sources for equations, data sets, factors or parameters, etc.
- Underwent a sensitivity analysis to assess model behavior for the range of parameters for which the model is applied
- Is reviewed at least every 10 years

B.2 Using models to forecast carbon stocks

The use of simulation models is required for estimating a Forest Project's baseline carbon stocks. Models may also be required to forecast actual carbon stocks expected under the Forest Project (e.g. in conjunction with determining expected harvesting volumes or in updating forest carbon inventories).

Inventory information from Appendix A must be incorporated into the simulation models to project carbon stocks over time. If a model has the ability to convert biomass to carbon, it must include all the carbon pools required by this protocol.

Projected baseline or actual carbon stocks must be portrayed in a graph depicting time in the x-axis and carbon tons in the y-axis. Baseline carbon stocks must be projected forward from the date of the Forest Project's offset project commencement. The graph should be supported with written characterizations that explain any annual changes in baseline carbon stocks over time. These characterizations must be consistent with the baseline analysis required in Section 0.

B.3 Modeling Requirements

A modeling plan must be prepared that addresses all required forecasting or updating of baseline and actual carbon stocks for the Forest Project. The modeling plan shall contain the following elements:

1. A description of all silviculture methods modeled. The description of each silviculture method will include:
    a. A description of the trees retained (by species groups if appropriate) at harvest.
    b. The harvest frequency (years between harvests).
    c. Regeneration assumptions.
2. A list of all legal constraints that affect management activities on the Project Area. This list must identify and describe the constraint and discuss the silviculture methods that will be modeled to ensure the constraint is respected.
3. A description of the site indexes used for each species and an explanation of the source of the site index values used.
4. A description of the model used and an explanation of how the model was calibrated for local use, if applicable.

Modeling outputs must include:

1. Periodic harvest, inventory, and growth estimates for the entire Project Area presented as total carbon tons and carbon tons per acre.
2. Harvest yield streams on modeled stands, averaged by silviculture method and constraints, which must include the period over which the harvest occurred and the estimated volume of wood removed.

Appendix C Estimating Carbon in Wood Products

Quantification Methodology

Wood products may constitute a reservoir for storing carbon over the long term. Projects that increase wood product production can receive credit for the resulting incremental carbon storage. By the same token, projects that reduce wood product production must account for the incremental *reduction* in stored wood product carbon. As indicated in Section 7, GHG reductions and GHG removal enhancements must be effectively "permanent," meaning that sequestered carbon associated with GHG reductions and removals must remain stored for at least 100 years. Wood product carbon is estimated by calculating the average amount of carbon that is likely to remain stored in wood products over a 100-year period.

The processes described here are adapted from the 1605(b) methodology (U.S. Department of Energy, 2007) for accounting for the long-term storage of wood products. Please see Smith, Heath, Skog, & Birdsey (2006) for a more detailed description since the 1605(b) procedure was adapted from this publication.

Because of the significant uncertainties associated with predicting wood product carbon storage over 100 years, the accounting requirements in this appendix are designed to err on the side of conservativeness. This means the calculations are designed to reduce the risk of overestimating the GHG reductions and GHG removal enhancements achieved by a Forest Project. One of the largest sources of uncertainty is predicting the amount of wood product carbon likely to be stored in landfills. To accommodate this uncertainty, and ensure that Forest Project GHG reductions and GHG removal enhancements are accounted for conservatively:

1. Landfill carbon storage is *excluded* from calculations of wood-product carbon in years where a Forest Project's actual harvesting volumes exceed estimated baseline harvesting volumes, as determined in Section 6.
2. Landfill carbon storage is *included* in calculations of wood-product carbon in years where a Forest Project's actual harvesting volumes are below estimated baseline harvesting volumes, as determined in Section 6.

Accounting for wood product carbon must be applied only to actual or baseline volumes of wood harvested from within the Project Area. Trees harvested outside of the Project Area are not part of the Forest Project and must be excluded from any calculations.

There are five steps required to determine carbon stored in wood products:

1. Determining the amount of carbon in harvested wood that is delivered to mills.
2. Accounting for mill efficiencies.
3. Estimating average carbon storage over 100 years in in-use wood products.
4. Estimating average carbon storage over 100 years in wood products in landfills (when applicable).
5. Summing the results to determine total average carbon storage over 100 years.

C.1 Determine the Amount of Carbon in Harvested Wood Delivered to Mills

The following steps must be followed to determine the amount of carbon in harvested wood:

1. Determine the amount of wood harvested (actual or baseline) that will be delivered to mills, by volume (cubic feet) or by green weight (lbs.), and by species for the current year (y). In all cases, harvested wood volumes and/or weights must exclude bark.

   a. Baseline harvested wood volumes and species are derived from modeling a baseline harvesting scenario, following the requirements in Section 6.
   b. Actual harvested wood volumes and species must be based on verified third-party scaling reports, where available. Where not available, documentation must be provided to support the quantity of wood volume harvested.
2. If a volume measurement is used, multiply the cubic foot volume by the appropriate wood density factor in Table C.1 (for projects located in the Pacific Southwest) or from the USFS Wood Handbook (other regions).[9] This results in pounds of biomass with zero moisture content.
3. If a weight measurement is used, subtract the water weight based on the moisture content of the wood. This results in pounds of biomass with zero moisture content.
4. Sum the dry weights for each harvested species to get a total dry weight for all harvested wood.
5. Multiply this total value by 0.5 pounds of carbon/pound of wood to compute the total carbon weight.
6. Divide the total carbon weight by 2,204.6 pounds/metric ton to convert to metric tons of carbon. This value is used in the next step, accounting for mill efficiencies.

Table C.1. Specific gravity and Wood Density of green softwoods and hardwoods by forest type for the Pacific Southwest from Table 1.4.

Forest Type	Specific Gravity of Softwoods	Specific Gravity of Hardwoods	Wood Density of Softwoods (lbs/ft^3)	Wood Density of Hardwoods (lbs/ft^3)
Mixed conifer	0.394	0.521	24.59	32.51
Douglas-fir	0.429	0.483	26.77	30.14
Fir-spruce-hemlock	0.372	0.510	23.21	31.82
Ponderosa pine	0.380	0.510	23.71	31.82
Redwood	0.376	0.449	23.46	28.02

C.2 Account for Mill Efficiencies

Multiply the total carbon weight (metric tons of carbon) derived in C.1 by the mill efficiency identified for the project's Assessment Area in the Forest Offset Protocol Resources section of ARB's website. This is the total carbon transferred into wood products. The remainder of the harvested carbon is considered to be immediately emitted to the atmosphere for accounting purposes in this protocol.

C.3 Estimate the Average Carbon Storage Over 100 Years in In-Use Wood Products

The amount of carbon that will remain stored in in-use wood products for at least 100 years depends on the rate at which wood products either decay or are sent to landfills. Decay rates depend on the type of wood product that is produced. Thus, in order to account for the

[9] The Wood Handbook (USFS, 2010) contains specific gravities for tree species in other regions. Multiply the specific gravity by the density of water (62.43 lbs/ft^3) to get wood density.

decomposition of harvested wood over time, a decay rate is applied to wood products according to their product class. To approximate the climate benefits of carbon storage, this protocol accounts for the average amount of carbon stored over 100 years. Thus, decay rates for each wood product class have been converted into "average storage factors" in

Table C.2, below.

To determine the average carbon storage in in-use wood products over 100 years, the first step is to determine what percentage of a Project Area's harvest will end up in each wood product class (Columns A-G in

Table C.2). This must be done by either:

1. Obtaining a verified report from the mill(s) where the Project Area's logs are sold indicating the product categories the mill(s) sold for the year in question; or
2. If a verified report cannot be obtained, looking up default wood product classes for the project's Assessment Area, as given in the most current Assessment Area Data File found on the Forest Offset Protocol Resources section of ARB's website.

If breakdowns for wood product classes are not available from either of these sources, classify all wood products as "miscellaneous."

Once the breakdown of in-use wood product categories is determined, use the worksheet in

Table C.2 to estimate the average amount of carbon stored in in-use wood products over 100 years:

1. Assign a percentage to each product class (columns A-G) according to mill data or default values for the project.
2. Multiply the total carbon transferred into wood products (determined in Section C.2) by the percentages in each column and insert the resulting values into boxes 3A through 3G.
3. Multiply the values in 3A-3G by the 100-year average storage factor and insert the results into boxes 4A through 4G.
4. Use Equation C.1 to calculate the average carbon stored in in-use wood products over 100 years (in units of CO_2-equivalent metric tons).

Equation C.1. Average Carbon Stored in In-Use Wood Products

$$\mathbf{WP_{in\text{-}use,\,y} = \sum(Table\ C.2,\ Row\ 4) \times 3.67}$$

Where,

$WP_{in\text{-}use,\,y}$ = Average carbon stored in in-use wood products over 100 years from wood harvested in year y (actual or baseline)

Table C.2. Worksheet to Estimate Long-Term Carbon Storage In In-Use Wood Products

	A	B	C	D	E	F	G
Wood Product Class	Softwood Lumber	Hardwood lumber	Softwood Plywood	Oriented Strandboard	Non Structural Panels	Miscellaneous Products	Paper
% in each class	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)
Metric tons C in each class	(3A)	(3B)	(3C)	(3D)	(3E)	(3F)	(3G)
100-year average storage factor (in-use)	0.463	0.250	0.484	0.582	0.380	0.176	0.058
Average C stored in in-use wood products (metric tons)	(4A)	(4B)	(4C)	(4D)	(4E)	(4F)	(4G)

C.4 Estimate the Average Carbon Storage Over 100 Years for Wood Products in Landfills

Wood product carbon in landfills is only calculated for years in which a Forest Project's actual harvesting volumes are below estimated baseline harvesting levels, as determined in Section 6. To determine the appropriate value for average landfill carbon storage, perform the following steps:

Step 1 – Calculate the average carbon storage over 100 years for wood products in landfills

Use the worksheet in

Table C.3 to estimate the average amount of wood product carbon stored in landfills over 100 years:

1. Assign a percentage to each product class (columns A-G) according to mill data or default values for the project (as determined in Section C.3).
2. Multiply the total carbon transferred into wood products (determined in Section C.2) by the percentages in each column and insert the resulting values into boxes 3A through 3G.
3. Multiply the values in 3A-3G by the 100-year average storage factor for landfill carbon and insert the results into boxes 4A through 4G.

Table C.3. Worksheet to Estimate Long-Term Carbon Storage in Wood Products in Landfills

	A	B	C	D	E	F	G
Wood Product Class	Softwood Lumber	Hardwood lumber	Softwood Plywood	Oriented Strandboard	Non Structural Panels	Miscellaneous Products	Paper
% in each class	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)	(X%)
Metric tons C in each class	(3A)	(3B)	(3C)	(3D)	(3E)	(3F)	(3G)
100-year average storage factor (landfills)	0.298	0.414	0.287	0.233	0.344	0.454	0.178
Average C stored in landfills (metric tons)	(4A)	(4B)	(4C)	(4D)	(4E)	(4F)	(4G)

Step 2 – Determine the appropriate value to use for wood product carbon in landfills

Use Equation C.2. Average Wood Product Carbon Stored in Landfills to determine the appropriate value for the average wood product carbon stored in landfills over 100 years (in units of CO_2-equivalent metric tons).

Equation C.2. Average Wood Product Carbon Stored in Landfills

$$If \sum_{n=1}^{y}(AC_{hv,n} - BC_{hv,n}) < 0, then\, WP_{landfill,y} = \sum(Table\ C.3, Row\ 4) \times 3.67$$

$$If \sum_{n=1}^{y}(AC_{hv,n} - BC_{hv,n}) > 0, then\ WP_{landfill,y} = 0$$

Where,

$WP_{landfill, y}$ = Average carbon stored in wood products in landfills over 100 years from wood harvested in the current year/reporting period (actual or baseline)

$AC_{hv, n}$ = Actual amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons

$BC_{hv, n}$ = Estimated average baseline amount of onsite carbon harvested in reporting period n (prior to delivery to a mill), expressed in CO_2-equivalent tons

y = The current year or reporting period

C.5 Determine Total Average Carbon Storage in Wood Products Over 100 Years

The total average carbon storage in wood products over 100 years for a given harvest volume (as determined in Section C.1) must be calculated and reported as follows (Equation C.3). The value derived for WP_{total} must be used for actual and baseline wood product carbon estimates ($AC_{wp,y}$ or $BC_{wp,y}$ in Equation 6.1) as appropriate, following the guidance in Section 6.

Equation C.3.

$$\mathbf{WP_{total,\,y} = WP_{in\text{-}use,\,y} + WP_{landfill,\,y}}$$

Where,

$WP_{total,\,y}$	=	Average carbon stored over 100 years from wood harvested in year y (actual or baseline)
$WP_{in\text{-}use,\,y}$	=	Average carbon stored in in-use wood products over 100 years from wood harvested in year y (actual or baseline)
$WP_{landfill,\,y}$	=	Average carbon stored in wood products in landfills over 100 years from wood harvested in year y (actual or baseline)

Appendix D Determination of a Forest Project's Reversal Risk Rating

A reversal risk rating must be determined for the Forest Project using the worksheets in this section. The worksheets are designed to identify and quantify the specific types of risks that may lead to a reversal, based on project-specific factors.

This risk assessment must be updated every time the Forest Project undergoes a verification site visit. Therefore, a Forest Project's risk profile and its assessment are dynamic. If estimated risk values and associated mitigation measures are updated as improvements in quantifying risks or changes in risks are determined, any adjustments to the risk ratings will affect only current and future year contributions to the Forest Buffer Account.

Risks that may lead to reversals are classified into the categories identified in Table D.1.

Table D.1. Forest Project Risk Types

Risk Category	Risk Type	Description	How managed in this protocol
Financial	Financial Failure Leading to Bankruptcy	Financial failure can lead to bankruptcy and/or alternative management decisions to generate income that result in reversals through over-harvesting or conversion	Default Risk
Management	Illegal Harvesting	Loss of project stocks due to timber theft	Default by Area
	Conversion to Non-Forest Uses	Alternative land uses are exercised at project carbon expense	Default Risk
	Over-Harvesting	Exercising timber value at expense of project carbon	Default Risk
Social	Social Risks	Changing government policies, regulations, and general economic conditions	Default Risk
Natural Disturbance	Wildfire	Loss of project carbon through wildfire	Default Risk
	Disease/Insects	Loss of project carbon through disease and/or insects	Default Risk
	Other Episodic Catastrophic Events	Loss of project carbon from wind, snow and ice, or flooding events	Default Risk

D.1 Financial Risk

Financial failure of an organization resulting in bankruptcy can lead to dissolution of agreements and forest management activities to recover losses that result in reversals. Forest Projects that employ a Qualified Conservation Easement, or that occur on public lands, have lower risk.

Table D.2. Financial Risk Identification

Applies to all projects		
Identification of Risk	**Contribution to Reversal Risk Rating**	
Default Financial Risk	**Forest Project not on public lands or without a Qualified Conservation Easement**	**Forest Project on public lands or with a Qualified Conservation Easement**
	5%	1%

D.2 Management Risk

Management failure is the risk of management activities that directly or indirectly could lead to a reversal. Forest Projects that occur on public lands, or employ a Qualified Conservation Easement are exempt from this risk category.

Management Risk I – Illegal Removals of Forest Biomass

Illegal logging occurs when biomass is removed either by trespass or outside of a planned set of management activities that are controlled by regulation. Illegal logging is exacerbated by lack of controls and enforcement activities.

Table D.3. Risk of Illegal Removals of Forest Biomass

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Harvesting Risk	0%

Management Risk II – Conversion of Project Area to Alternative Land Uses

High values for development of housing and/or agriculture may compete with timber and carbon values and lead to a change in land use that affects carbon stocks. The risk of conversion of any Project Area to other non-forest uses is related to the probability of alternative uses, which are affected by many variables, including population growth, topography, proximity to provisions and metropolitan areas, availability of water and power, and quality of access to the Project Area.

Table D.4. Risk of Conversion to Alternative Land Use

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
With Qualified Conservation Easement that explicitly encumbers all development rights	0%
Without Qualified Conservation Easement	2%

Management Risk III – Over-Harvesting

Favorable timber values, among other reasons, may motivate an Offset Project Operator or Authorized Project Designee to realize timber values at the expense of managing carbon stocks for which ARB or registry offset credits have been issued. Additionally, reversals can occur as the result of harvest associated with fuels treatments.

Table D.5. Risk of Over-Harvesting

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
With Qualified Conservation Easement that explicitly encumbers timber harvesting associated with project stocks	0%
Without Qualified Conservation Easement	2%

D.3 Social Risk

Social risks exist due to changing government policies, regulations, and general economic conditions. The risks of social or political actions leading to reversals are low, but could be significant.

Table D.6. Social Risk Identification

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Social Risk	2%

D.4 Natural Disturbance Risk

Natural disturbances can pose a significant risk to the permanence of the GHG reductions and GHG removal enhancements. Natural disturbance risks are only partially controllable by

management activities. Management activities that improve resiliency to wildfire, insects, and disease can reduce these risks. Management activities that shift harvesting practices from live sequestering trees to trees that have succumbed to natural disturbances reduce or negate the reversal depending on the size and location of the disturbance.

Natural Disturbance Risk I – Wildfire

A wildfire has the potential to cause significant reversals, especially in certain carbon pools. These risks can be reduced by certain techniques including reducing surface fuel loads, removing ladder fuels, adding fuel breaks, and reducing stand density. However, these techniques cannot reduce emission risk to zero because all landowners will not undertake fuel treatments, nor can they prevent wildfire from occurring.

Table D.7. Natural Disturbance Risk I – Wildfire

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
United States Default Fire Risk	4%
If fuel treatments have been implemented for the Project Area, reduce the value above by the appropriate Y% as indicated below.*	(4%) x Y%

* Depending on the level of fuel treatments, the Y% is set as follows:
- high level of fuel treatments = 50%,
- medium level of fuel treatments = 66.3%,
- low level of fuel treatments = 82.6%,
- no fuel treatments = 100%.

Natural Disturbance Risk II - Disease or Insect Outbreak

A disease or insect outbreak has the potential to cause a reversal, especially in certain carbon pools.

Table D.8. Natural Disturbance Risk II – Disease or Insect Outbreak

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
Default Risk Contribution from Disease or Insect Outbreak	3%

Natural Disturbance Risk III - Other Episodic Catastrophic Events

A major wind-throw event (hurricane, tornado, high wind event) has the potential to cause a reversal, especially in certain carbon pools.

Table D.9. Natural Disturbance Risk III – Other Episodic Catastrophic Events.

Applies to all projects	
Identification of Risk	**Contribution to Reversal Risk Rating**
Default Risk Contribution from Other Catastrophic Events	3%

D.5 Summarizing the Risk Analysis and Contribution to Buffer Account

Use table D.10 to summarize the Forest Project's reversal risk rating. As indicated above, projects that employ a Qualified Conservation Easement, or that occur on public lands, are exempt from certain risk categories. Such Qualified Conservation Easements must clearly identify the goals and objectives of the Forest Project according to the terms of this protocol.

Table D.10. Project Contribution to the Buffer Account Based on Risk.

Risk Category	**Contribution from Risk Descriptions Above**		
	Source	Forest Project without a Qualified Conservation Easement and/or Public Ownership	Forest Projects with a Qualified Conservation Easement and/or Public Ownership
Financial Failure	Default Risk	5%	1%
Illegal Forest Biomass Removal	Default Risk	0%	0%
Conversion	Default Risk	2%	0%
Over-Harvesting	Default Risk	2%	0%
Social	Default Risk	2%	2%
Wildfire	Calculated Risk from worksheet	X%	X%
Disease or Insect Outbreak	Calculated Risk from worksheet	3%	3%
Other Catastrophic Events	Calculated Risk from worksheet	3%	3%

Completing the Risk Rating Analysis:

The Forest Project's reversal risk rating is calculated as follows:

$$100\% - \begin{pmatrix} (1 - FinancialFailure\%) \times (1 - IllegalForestBiomassRemoval\%) \times (1 - Conversion\%) \\ \times (1 - OverHarvesting\%) \times (1 - SocialRisk\%) \times (1 - Wildfire\%) \times (1 - Disease/InsectOutbreak\%) \\ \times (1 - OtherCatastrophicEvents\%) \end{pmatrix}$$

Appendix E Reforestation Project Eligibility

This appendix presents a standardized approach to determine whether reforestation activities on lands that have undergone a Significant Disturbance are likely to be "business as usual," and therefore not eligible for registration based on the net present value for the timber expected to be produced from reforestation. A reforestation project is considered "business as usual" if the net present value for expected timber is $0 or more according to standard assumptions underlying Table E.1.

To determine whether a reforestation project is eligible, perform the following steps:

1. Identify whether site preparation costs[10] are High or Low:
    a. Site preparation costs are High if:
        i. Competing species management (including mechanical removal and/or use of herbicides) has been or will be conducted on 50 percent or more of the Project Area; or
        ii. Soil ripping has occurred on more than 50 percent of the Project Area.
    b. Site preparation costs are Low for all other projects.
2. Identify the value of harvested products (High, Medium, Low, or Very Low) corresponding to the project's Assessment Area, from the lookup table in the Forest Offset Protocol Resources section of ARB's website.
3. Identify the standard Rotation Age for the project's Assessment Area, from the lookup table in the Forest Offset Protocol Resources section of ARB's website.
4. Identify the site class category for the Project Area. The category must be consistent with the stated site productivity in the project's submission form. Projects with mixed site classes must round to the nearest site class category based on a weighted average.
    a. Site Classes I and II are classified as 'Higher'.
    b. Site Classes III, IV, and V are classified as 'Lower'.
5. Determine whether the Forest Project is "eligible" or "not eligible" according to the identified site preparation costs, value of harvested products, rotation age, and site class, as indicated in Table E.1.

[10] All Forest Projects are assumed to have similar costs related to the cost of seedlings and planting; site preparation costs, however, can vary depending on circumstances.

Table E.1. Determination of Reforestation Project Eligibility

Site Preparation Costs	Value of Harvested Products	Rotation Age (Length)	Site Class	Eligibility	Scenario #
High Site Preparation	High	Short, Medium, Long	Higher	Not Eligible	1
			Lower	Not Eligible	2
		Extremely Long	Higher	Eligible	3
			Lower	Eligible	4
	Medium	Short, Medium	Higher	Not Eligible	5
			Lower	Not Eligible	6
		Long	Higher	Not Eligible	7
			Lower	Eligible	8
		Extremely Long	Higher	Eligible	9
			Lower	Eligible	10
	Low	Short	Higher	Not Eligible	11
			Lower	Eligible	12
		Medium, Long, Extremely Long	Higher	Eligible	13
			Lower	Eligible	14
	Very Low	Short, Medium, Long, Extremely Long	Higher	Eligible	15
			Lower	Eligible	16
Low Site Preparation	High	Short, Medium	Higher	Not Eligible	17
			Lower	Not Eligible	18
		Long, Extremely Long	Higher	Not Eligible	19
			Lower	Eligible	20
	Medium	Short, Medium	Higher	Not Eligible	21
			Lower	Not Eligible	22
		Long	Higher	Not Eligible	23
			Lower	Eligible	24
		Extremely Long	Higher	Eligible	25
			Lower	Eligible	26
	Low	Short	Higher	Not Eligible	27
			Lower	Not Eligible	28
		Medium	Higher	Not Eligible	29
			Lower	Eligible	30
		Long, Extremely Long	Higher	Eligible	31
			Lower	Eligible	32
	Very Low	Medium, Long, Extremely Long	Higher	Eligible	33
			Lower	Eligible	34
		Short	Higher	Not Eligible	35
			Lower	Not Eligible	36

Appendix F Determining a Value for Common Practice

Quantification Methodology

Forest Assessment Areas Introduction

Assessment areas are used to provide standardized regional data for offset project development. An assessment area is generally defined as a forest vegetation community that shares common environmental, economical, and regulatory attributes. The Forest Offset Protocol Resources section of ARB's website provides data, by assessment area, necessary to calibrate and/or implement project accounting, including:

- Common Practice – The average carbon stocks (metric tons) of the above ground portion of live trees on private lands. The average carbon stock is the result of the suite of management activities within the assessment area. The common practice value is the extent to which improved forest management projects can receive credit for avoided emissions. (See Section 6.2.)
- Diversity Index – The maximum amount (by carbon percentage) of any one native species allowed within a project. (See Section 3.9.2.)
- The rotation length commonly used in the assessment area and the value of harvest for incorporating in a financial test for reforestation projects (see Appendix E).
- The mill efficiency used for calculating wood products (see Appendix C).
- The wood product classes generated for calculating wood products values (see Appendix C).

Defining Assessment Areas

The U.S. Forest Service Forest Inventory and Analysis Program (FIA) is the basis for development of assessment areas. The FIA program collects data on U.S. forests using an extensive array of coordinated sample plots throughout the nation. Together the plots comprise a national inventory system designed to assess the state of U.S. forests on an ongoing basis. The hierarchical and spatial nature of FIA data make it possible to group sample field plots by geographical location. FIA plots are assigned an attribute referred to as 'forest type' that identifies the dominant vegetation present at the plot. Forest Types were combined into forest communities following a process described further below. An assessment area is a forest community within a defined geographical unit. The geographical units are discussed below.

Ecosections are spatial units and can be mapped. The geographical units that contain assessment areas are based on individual ecosections or combined ecosections (called supersections). Supersections were created in order to stratify the plots into high site class and low site class (where possible) and to increase the statistical reliability of the common practice estimates derived for each assessment area. The combination of ecosections into supersections only occurred where adjacent ecosections share similar environmental, economic, and regulatory attributes. Ecosections are combined into supersections if:

1. The ecosections are adjacent to each other.
2. They share a similar distribution of plots by forest types, which indicates that the ecosections share similar climate, elevation, and other environmental variables.
3. The economics of forest management are similar between the ecosections. The criteria considered to determine economic commonality between ecosections include forest product

generation, transportation networks, forest product mill types, and wood products markets. This was based on professional knowledge of regional timber markets.

4. Regulations between ecosections are relatively homogeneous across ecosection boundaries. Ecosections are not combined into supersections in cases where forest practice regulations between adjoining administrative units are known to be markedly different.

The Forest Service computed the statistics for the combined forest types aggregated at the supersection level and disaggregated at the ecosection level. The statistics are reported on a per acre basis and include board foot volume, basal area (square feet), above ground carbon tons, and the sampling error. Ecosections were not combined into supersections if the aggregation changed average standing carbon stocks of any assessment areas by more than 10%, indicating that there are environmental, economic or regulatory differences affecting the forest stocks within these communities.

The aggregation of forest types into forest communities that define assessment areas is based on the natural forest communities found within the ecosections rather than the presence of a single dominant species as in plantation management. As an example, the Northwest Coast Range contains many forest holdings of intensively managed Douglas-fir forests, yet the natural forest community contains many other species such as western hemlock, Sitka spruce, and red alder, among others. The plots used to define the assessment area, as well as the common practice statistic, are the entire set of plots found in the natural forest community. No effort is made to isolate assessment areas based on the existence of plantations. Successional stage, including the presence of shade tolerance species, and management influence on species prevalence is not a basis for stratifying distinct communities. The Forest Offset Protocol Resources data on ARB's webpage displays the associations of forest species (forest types) and assessment areas for all of the ecosections and supersections. Figure F.1 summarizes conceptually the methodology for delineating assessment areas.

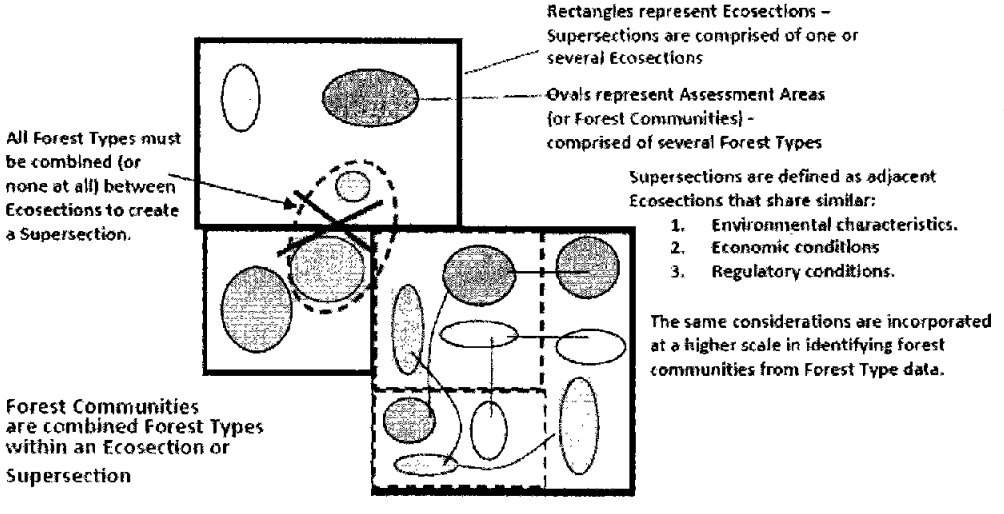


Figure F.1 Schematic of Process to Define Assessment Areas

Determining a Value for Common Practice

The following requirements and methods provide step by step instructions for determining the appropriate Common Practice value for an Improved Forest Management project based on its geographic location and boundaries.

1. **Determine the Geographic Ecosection(s) or Supersection(s) Within Which the Project Area is Located**
   The Offset Project Operator or Authorized Project Designee must determine the geographic Ecosection(s) or Supersection within which the Project Area is located by consulting maps of Supersections. These maps can be downloaded from the Forest Offset Protocol Resources section of ARB's website in either a .pdf format or a Geographical Information System (GIS) shapefile.

2. **Determine the Acreage of the Project Area That Falls Within Each Assessment Area Contained in the Ecosection(s) or Supersection(s)**

   Ecosections and Supersections may consist of one or many Assessment Areas. Assessment Areas are groupings of tree species that are commonly found in association with each other, as in a vegetation community. Assessment Areas are not mapped since the geographic locations of forest communities vary based on highly resolute environmental variables. To determine which Assessment Areas are included within the Project Area, compare the tree species in the Project Area to the species list associated with each Assessment Area in the project's Ecosection(s) or Supersection(s) (identified in Step 1). Tree species information must be looked up using the most current Assessment Area Data File from the Forest Offset Protocol Resources section of ARB's website. The minimum mapping resolution for vegetation communities is 20 acres. Therefore, any contiguous area 20 acres or greater within the Project Area that consists of a separate vegetation community must be independently mapped.

3. **Where Necessary, Stratify Project Area Acres According to Whether They Are High or Low Site Class**

   The Assessment Area Data File on the Forest Offset Protocol Resources section of ARB's website provides data for each Assessment Area by high, low, or all site classes. For Assessment Areas where data are attributed for high and low site classes, the Offset Project Operator or Authorized Project Designee must further stratify the Project Area and identify the acreage that falls within each site class.

   The computation of the statistics in the Assessment Area Data File (on a per acre basis) for board foot volume, basal area (square feet), and CO_2 equivalent was done for high and low site classes wherever the FIA plots were available in adequate quantity to achieve a sampling error of 18 percent or less. The board foot volume and basal area statistics are presented only to elucidate comparisons to the Common Practice (CO_2 equivalent) statistic. Board foot volume and basal area statistics are not used for other purposes in the protocol.

   For stratification purposes, a "high" site class means a Timber Site I or II (Forest Service Types I, II, and III). A low site class means a Timber Site III, IV, or V (Forest Service Types IV – VII). Landowners must determine the portion of the Project Area that is in each site class for each Assessment Area using soils data from a state or federal

agency, direct site class data from a state or federal agency, attestation from a state forester, or through field analysis. Whatever method is used, documentation of the analysis must be provided to the verifier at the project's initial verification.

4. **Identify the Common Practice Statistic Associated with Each Assessment Area and Site Class Stratum**

   For each Assessment Area and Site Class within the Project Area, identify the appropriate Common Practice statistic from Assessment Area Data File. The value displayed in the Assessment Area Data File indicates CO_2 equivalent metric tons per acre in the above ground portion (bole, bark, top and branches) of live trees.

   If data for an Assessment Area are provided for both high and low site classes, and a Offset Project Operator or Authorized Project Designee is unable or unwilling to stratify the Project Area into site classes using an acceptable method described above, then the high site-class Common Practice statistic must be used for all acres within the Assessment Area.

5. **Determine a Value for Common Practice for the Entire Project Area**

   Determine a single Common Practice value for the entire Project Area by calculating the average of the Common Practice statistics for each Assessment Area and site class, weighted by the number of acres of each Assessment Area and site class within the Project Area. See Table F1 for an example.

Table F1. Example of Common Practice Statistic Calculation

Ecosection(s) /Supersection(s)	Assessment Area	Site Class	Acres	Common Practice (Metric Tons CO2-e)
Name the Ecosection(s)/Supersection(s) the project is found within.	*Identify the Assessment Areas the project is in. If the project is in more than one site class for an Assessment Area, enter the Assessment Area twice*	*Enter the Site Class Value*	*Acres for each Assessment Area-Site Class Combination*	*Enter the Value from the most current Assessment Area Data File*
Adirondacks & Green Mountains	Adirondacks & Green Mountains Northeast Conifers	High	1,000	91.8
Adirondacks & Green Mountains	Adirondacks & Green Mountains Northeast Conifers	Low	100	84.4
Adirondacks & Green Mountains	Adirondacks & Green Mountains Northern Hardwood	High	50	102.8
Total Acres / Weighted Average Common Practice			**1,150**	**91.6**

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER ADOPTION OF PROPOSED AMENDMENTS TO THE AB 32 COST OF IMPLEMENTATION FEE REGULATION

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider amendments to California's existing AB 32 Cost of Implementation Fee Regulation (sections 95200-95207, title 17, California Code of Regulations (CCR)), which was developed pursuant to requirements of the California Global Warming Solutions Act of 2006.

DATE: October 20, 2011

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 20, 2011, and may continue at 8:30 a.m., Friday, October 21, 2011. This item may not be considered until October 21, 2011. Please consult the agenda for the hearing, which will be available at least 10 days before October 20, 2011, 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 95201, 95202, 95203, 95204, and 95205, title 17, CCR: the AB 32 Cost of Implementation Fee Regulation (Fee Regulation).

Background:

With the passage of Assembly Bill (AB) 32, the California Global Warming Solutions Act of 2006 (Health and Safety Code sections 38501-38599), 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 reducing emissions to 1990 levels by 2020. The administration, implementation, and enforcement of measures to achieve the emissions reductions goals will require a stable and continuing source of funding.

AB 32 authorizes ARB to adopt a schedule of fees to be paid by the sources of GHG emissions.

On May 8, 2009, ARB released the Staff Report: Initial Statement of Reasons for Rulemaking, Proposed AB 32 Cost of Implementation Fee Regulation and Proposed Amendment to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR). At the Board's September 25, 2009, hearing the Board directed the Executive Officer to finalize the AB 32 Cost of Implementation Fee Regulation (Fee Regulation) and the amendments to the MRR. The Executive Officer subsequently adopted these regulations and submitted them to the California Office of Administrative Law (OAL). The regulations were approved by OAL and became legally effective on July 17, 2010.

Information about the Fee Regulation can be found at:
http://www.arb.ca.gov/regact/2009/feereg09/feereg09.htm.

DESCRIPTION OF THE PROPOSED REGULATORY ACTION

ARB staff is proposing amendments to the Fee Regulation to clarify regulatory language and conform with recent proposed amendments to the MRR that are expected to become legally effective in late 2011. The proposed amendments consist of administrative changes that add, revise, or delete definitions; change or exclude emissions reporting for some entities; clarify provisions that caused confusion in the first year of implementation; and revise applicability to exclude certain very small GHG emitters.

ARB currently expects to propose additional revisions to the MRR, after the publication of this notice. If such revisions are made to the MRR, ARB may propose additional modifications to the Fee Regulation to be consistent with the revisions to the MRR. Any additional modifications to the Fee Regulation would be made available for a 15-day comment period after the October 2011 Board hearing.

COMPARABLE FEDERAL REGULATIONS

There are no federal regulations that are comparable to this Fee Regulation or proposed amendments to the Fee Regulation.

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 Amendments to the AB 32 Cost of Implementation Fee 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 regulation, 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, August 31, 2011.

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.

Inquiries concerning the substance of the proposed Fee Regulation may be directed to the designated agency contact persons, Mr. Bill Blackburn, Air Pollution Specialist, at (916) 322-7154, or Mr. David Mallory, Manager of the Climate Change Policy Section, at (916) 445-8316.

Further, the agency representative and designated back-up contact persons, to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Ms. Lori Andreoni, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, or Ms. 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.

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/2011/feereg11/feereg11.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies, private persons and businesses in reasonable compliance with the proposed regulatory action are presented below. An assessment of the economic impacts of the proposed amendments to the Fee Regulation is included in the ISOR for this regulatory item.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that, except as discussed below, the proposed amendments to the Fee Regulation 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 part 7 (commencing with section 17500), division 4, title 2 of the Government Code, or other nondiscretionary costs or savings to State or local agencies.

The proposed amendments would impose minimal additional costs on some State and local agencies, but not on school districts. One State agency, the California Department of Water Resources, is presently subject to the existing Fee Regulation, and as a result

of the proposed amendments would incur an additional cost that is estimated to be less than $100.

The Executive Officer has determined that the proposed regulatory action will create savings to some local agencies. Five local agencies, presently subject to the Fee Regulation, are very small GHG emitters and would no longer be required to pay fees after adoption of the proposed amendments. The remaining local agencies that serve as retail providers and marketers of imported electricity and are currently subject to the existing Fee Regulation, 44 in total, would collectively pay additional fees that are estimated to be less than $1500 as a result of the proposed amendments.

The Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies or school districts 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.

The proposed amendments to the Fee Regulation are technical amendments to conform with amendments made to the MRR and do not significantly modify the scope of the current Fee Regulation. In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses. The proposed amendments will not result in a net change to the revenue collected under the fee regulation. Approximately 20 to 25 current fee payers would no longer be required to report emissions through the MRR, and therefore would no longer be required to pay under the fee regulation. An estimated $26,000 (based on 2008 reported emissions) would be distributed among the approximately 131 remaining public and private fee payers. Affected businesses should be able to absorb the increased cost without incurring a significant adverse economic impact. 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 accordance with Government Code section 11346.3, 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. An assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

The Executive Officer has also determined that, pursuant to title 1, CCR, section 4, the proposed regulatory action would not affect small businesses. The businesses affected by the proposed amended regulation include petroleum producers, natural gas producers, and other similar businesses which are excluded from the Administrative Procedure Act "small business" definition found in Government Code section

11342.610. 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 Fee Regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the agency or that has otherwise been identified and brought to the attention of the agency, 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.

SUBMITTAL OF COMMENTS

Interested members of the public may present comments orally or in writing at the meeting, and comments may be submitted by postal mail or electronic submittal before the meeting. The public comment period for this regulatory item will begin on September 3, 2011. To be considered by the Board, written comments, not physically submitted at the meeting, must be submitted on or after September 3, 2011, and received **no later than 12:00 noon on October 19, 2011**, 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

New Feature

You can now 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. Additionally, this information may become available via Google, Yahoo, and any other search engines.

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 to 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.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under the authority granted in Health and Safety Code sections 38510, 38597, 39600, and 39601. This action is proposed to implement, interpret, and make specific Health and Safety Code sections 38501, 38505, 38510, 38530, 38597, 39300, 39600, and 39601.

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 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 (i.e., Braille, large print, etc.) 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.

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 (por decir, sistema Braille, o en impresión grande) 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

James N. Goldstene
Executive Officer

Date: August 23, 2011

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



INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

PROPOSED AMENDMENTS TO THE AB 32 COST OF IMPLEMENTATION FEE REGULATION

Release Date: August 31, 2011

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

Public Hearing to Consider

PROPOSED AMENDMENTS TO THE AB 32 COST OF IMPLEMENTATION FEE REGULATION

To be considered by the Air Resources Board at a
Public Hearing on October 20, 2011, at:

Byron Sher Auditorium
Air Resources Board, Cal/EPA Headquarters
1001 I Street
Sacramento, CA 95814

This report has been reviewed by the staff of the California Air Resources Board. Publication 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.

State of California
AIR RESOURCES BOARD

PROPOSED AMENDMENTS TO THE AB 32 COST OF IMPLEMENTATION FEE REGULATION

Acknowledgements

This report was prepared with the assistance and support from other divisions and offices of the Air Resources Board. In addition, we would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations.

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APPENDICES

Appendix A Proposed Amendments to the AB 32 Cost of Implementation Fee Regulation

Appendix B Rationale for Proposed Amendments to Definitions – Section 95202

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Executive Summary

In this rulemaking, California Air Resources Board (ARB or Board) staff is proposing amendments to the Assembly Bill (AB) 32 Cost of Implementation Fee Regulation (Fee Regulation). The proposed amendments to the Fee Regulation are primarily designed to modify language to conform with proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) which are anticipated to become legally effective in late 2011. ARB staff currently expects to propose additional revisions to the MRR, after the release of this Initial Statement of Reasons ("Staff Report"). If such revisions are made to the MRR, staff anticipates proposing additional modifications to the Fee Regulation to be consistent with the additional revisions to the MRR. Any additional modifications to the Fee Regulation would be made available for a 15-day comment period after the October 2011, Board Hearing.

The proposed amendments to the Fee Regulation consist of administrative changes that add, revise, or delete definitions; change or exclude emissions reporting for some entities; revise applicability to exclude certain very small entities; and clarify provisions that caused confusion in the first year of implementation.

The amendments to the MRR include raising the applicability threshold on electricity generating facilities (EGFs) from 2,500 metric tons of CO_2 ($MTCO_2$) to 10,000 metric tons of CO_2 equivalent ($MTCO_2e$) annually. The proposed amendments to the Fee Regulation include conforming language, resulting in some EGFs not being subject to the Fee Regulation. It is expected that this affects a small number of EGFs.

This Staff Report is required by the California Administrative Procedure Act. Appendix A contains the proposed amendments to the Fee Regulation. The proposed changes are shown in underline and ~~strikeout~~ format.

This Executive Summary provides a brief background on the Fee Regulation, a description of the proposed amendments to the Fee Regulation, and explains the rationale for the proposed changes.

What is the purpose of the AB 32 Cost of Implementation Fee Regulation?

AB 32, the California Global Warming Solutions Act of 2006 (Health and Safety Code sections 38501-38599), established a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California. Under AB 32, ARB is required to develop regulations that will ultimately reduce California's GHG emissions to the 1990 baseline year by 2020. AB 32 provides ARB with the authority to adopt a fee schedule to be paid by sources of GHG emissions. The purpose of the Fee Regulation is to establish the means to fund the State's AB 32 costs and to repay loans that were approved by the Legislature and the Governor for fiscal years (FY) 2007-2008 through 2009-2010.

The Fee Regulation assesses fees on sources of GHGs from the most widely used fossil fuels, including gasoline; diesel; coal; petroleum coke; catalyst coke; refinery gases; and natural gas. A fee is also assessed on non-combustion GHG process emissions from refineries and cement manufacturers. Finally, a fee is imposed on the GHG emissions associated with the generation of imported electricity, consistent with treatment of in-state generation. Together, emissions from fuel combustion, refining, manufacturing process emissions, and imported electricity account for over 85 percent of California's GHG emissions.

What is the status of the Implementation of the Fee Regulation?

The Fee Regulation was considered by the Board at its September 25, 2009, public hearing and became effective on July 17, 2010. In April 2011, ARB sent out invoices for FY 2010-2011 to 284 fee payers based on the total required revenue of $62.1 million. This total revenue includes both AB 32 implementation expenses for the FY 2010-2011 of $35.2 million and a $26.9 million repayment on program start-up loans. At the time of publication of this Staff Report, ARB is in the process of sending out invoices for FY 2011-2012 to 294 fee payers based on the total revenue requirement of $61 million. Revenue requirements are established by the California Budget Act. For more information on implementation see Chapter I of the Staff Report.

Why is ARB proposing amendments?

Staff is proposing amendments to the Fee Regulation to conform with proposed changes to the MRR and to clarify provisions where there has been confusion in the first year of implementation. In December 2010, the Board considered modifications to certain sections of the MRR. Entities subject to the MRR and those subject to the Fee Regulation must use the same Internet-based reporting tool to report all required data.

For many sectors, the reporting requirements of the MRR provide the necessary data to comply with the Fee Regulation. These data are reported only once to limit the administrative burden on the regulated entities. In order for the data to be reported for both regulations simultaneously, in most cases, identical definitions are necessary for clarity. To conform definitions and align reporting dates with the MRR, amendments to the Fee Regulation are proposed to ensure relevant language is as consistent as possible.

While most definitions in the proposed amendments to the Fee Regulation are identical to the MRR, some are different, by necessity, due to specific distinctions between the two regulations. These proposed amendments to definitions include the phrase "(Fee Regulation only)."

In addition, ARB staff is proposing clarifying changes to some specific sections of the Fee Regulation, based on experience gained from the first year of implementation of the Fee Regulation.

The proposed amendments are not intended to revisit decisions previously approved by the Board. The proposed changes are technical in nature and do not significantly change the applicability or calculation of fees established by the Fee Regulation.

What amendments are being proposed?

Amendments are proposed to the following sections of the regulation: section 95201 "Applicability;" section 95202 "Definitions;" section 95203 "Calculation of Fees;" section 95204 "Reporting and Recordkeeping Requirements;" and section 95205 "Payment and Collection." The proposed amendments to the sections are summarized below. Chapter III of the Staff Report contains more detailed information on each proposed amendment.

1. Applicability (section 95201)

Limited changes in applicability are included in the proposed amendments to clarify applicability of the Fee Regulation, and to conform to the proposed MRR amendments. The proposed amendments to the MRR include raising the applicability threshold on EGFs from 2,500 $MTCO_2$ to 10,000 $MTCO_2e$ annually. The proposed amendments to the Fee Regulation include conforming language, which will result in some EGFs no longer being subject to the Fee Regulation. Based on 2008 reported emissions, there are 24 EGFs with emissions between 2,500 $MTCO_2$ and 10,000 $MTCO_2e$. Therefore, assuming identical prospective emissions, these 24 entities would be excluded from the fee. However, because reported emissions vary annually, it is expected that 20-25 EGFs would no longer being subject to the Fee Regulation.

2. Definitions (section 95202)

Section 95202 "Definitions," provides all of the terms used in the Fee Regulation which are not self-explanatory. Numerous changes to the definitions of the Fee Regulation are being proposed as part of the amendments. The proposed amendments to the Fee Regulation include the modification of approximately 50 definitions, the addition of approximately 35 new definitions, and the deletion of three definitions. Most of the modified definitions have been changed to make them consistent with definitions in the amendments to the MRR. These proposed definition changes are further explained in Chapter III of the Staff Report.

3. Calculation of Fees (section 95203)

Minor amendments are being proposed to the fee calculation methodology to ensure consistency with the proposed changes in the definitions. The proposed

amendments to the Fee Regulation would result in different fee calculation procedures for report years 2008 through 2010, and those fee calculation procedures for report years 2011 and later. This differentiation in fee calculation procedures is necessary to reflect how the Fee Regulation determines fees based on the currently effective MRR and the amended MRR, which is anticipated to become legally effective in late 2011.

4. Reporting and Recordkeeping Requirements (section 95204)

Amendments are being proposed to the reporting and recordkeeping requirements to: 1) clarify administrative information such as the billing address and identification of the official responsible for payment that is required for all facilities, fuel suppliers, and electric power entities subject to the Fee Regulation; and 2) conform to the MRR reporting due dates.

5. Payment and Collection (Section 95205)

The proposed amendments would clarify that an entity must remit payment to ARB within 60 days of the fee determination notice date, rather than the date of receipt of a fee determination notice. This clarification is necessary because ARB does not have the ability to determine when an entity receives a fee determination notice.

What are the environmental impacts of the proposed amendments?

1. Environmental Impacts

The proposed amendments to the Fee Regulation are administrative changes that add, revise, or delete definitions, and modify or exclude emissions reporting requirements for some entities. Staff evaluated the potential environmental impacts from the proposed amendments to the Fee Regulation and determined that no potential significant adverse environmental impacts would result from the proposed amendments.

2. Environmental Justice

This proposal is consistent with the ARB's Environmental Justice Policy to reduce health risks in all communities, including low-income and minority communities.

Staff has determined that the proposed amendments to the Fee Regulation would not result in an adverse impact to air quality, and would not result in an increase in exposure to pollutants. Adoption and implementation of amendments to the Fee Regulation will have no adverse impacts on environmental justice communities.

What are the economic impacts of the proposed amendments?

There is no net change in the amount of the fees that are collected. Most of the proposed amendments are changes in language to conform to the MRR. Staff believes approximately 20 to 25 EGFs will no longer be required to report emissions as a result of the MRR amendments, and will no longer be subject to the Fee Regulation. The estimated $26,000 that would otherwise be paid by these entities will be redistributed, based on fuel and emissions reported data, among the approximately 131 remaining fee payers. The impact of $26,000 being redistributed to all of the remaining fee payers would range from approximately $0.03 to $2,200 per invoice. Examples of estimated changes to fee payer's invoices are as follows: a facility originally invoiced $5 million would see an increase of $2,100; a facility originally invoiced $1 million would see an increase of $420; a facility originally invoiced $10,000 would see an increase of $4; twenty-six local agencies will collectively pay additional fees totaling $1,465. One State agency will have an $85 increase in costs and one federal agency will pay an estimated $30 more in fees.

How did staff develop the proposed amendments?

ARB staff developed the proposed amendments to the Fee Regulation by working closely with staff that developed the MRR, the public, and the regulated entities.

A public workshop was held on January 21, 2011, to receive comments on the proposed amendments. The workshop notice was posted to ARB's website and emailed to subscribers of the climate change list serve. A copy of the workshop notice is contained in Appendix C of this Staff Report. ARB staff received oral comments during the workshop. Three entities also submitted written comments after the workshop. These comments were reviewed by staff and considered in the draft proposed amendments.

What is staff's recommendation?

We recommend that the Board approve the proposed amendments to the Fee Regulation.

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I. Introduction

In this rulemaking, Air Resources Board (ARB or Board) staff is proposing amendments to the Assembly Bill (AB) 32 Cost of Implementation Fee Regulation (Fee Regulation). The purpose of the proposed amendments to the Fee Regulation is primarily to modify language to conform with proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR) which are expected to become legally effective in late 2011.

The proposed amendments to the Fee Regulation include changes in applicability to exclude certain small greenhouse gas (GHG) emitters; add, revise, or delete definitions; modify language for clarity and consistency with proposed amendments to the MRR; and change certain reporting deadlines. The regulation is codified in title 17, California Code of Regulations, sections 95200 to 95207.

This Staff Report provides ARB staff's technical justification and analysis of the proposed amendments.

Background and Enabling Legislation

AB 32, the California Global Warming Solutions Act of 2006 (Health and Safety Code sections 38501-38599), established a comprehensive, multi-year program to reduce GHG emissions in California. Under AB 32, ARB is required to develop regulations that will ultimately reduce California's GHG emissions to the 1990 baseline year by 2020. AB 32 also provides ARB the authority to adopt a fee schedule to fund the State's cost to develop, implement and enforce these regulations and other provisions of the law.

The fee is authorized in HSC section 38597, which states:

> "The State board may adopt by regulation, after a public workshop, a schedule of fees to be paid by the sources of greenhouse gas emissions regulated pursuant to this division, consistent with Section 57001. The revenues collected pursuant to this section, shall be deposited into the Air Pollution Control Fund and are available upon appropriation, by the Legislature, for purposes of carrying out this division."

The purpose of the Fee Regulation is to establish the means to fund the State's AB 32 costs and to repay loans that were approved by the Legislature and the Governor for fiscal years (FY) 2007-2008 through 2009-2010. The Fee Regulation assesses fees on sources of GHGs from the most widely used fossil fuels, including gasoline; diesel; coal; petroleum coke; catalyst coke; refinery gases; and natural gas. A fee is also assessed on non-combustion GHG process emissions from refineries and cement manufacturers. Finally, a fee is imposed on the GHG emissions associated with the generation of imported electricity. Together,

emissions from fuel combustion; refining; manufacturing process emissions; and imported electricity account for over 85 percent of California's GHG emissions.

On May 8, 2009, ARB released the staff report: Initial Statement of Reasons for Rulemaking, Proposed AB 32 Cost of Implementation Fee Regulation and Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. The Board directed the Executive Officer to finalize the AB 32 Cost of Implementation Fee Regulation and the amendments to the MRR at its September 25, 2009, hearing.

In February and March 2010, ARB modified the Fee Regulation to reflect the Board's direction from the September 2009 hearing. All modifications were made available for public comment for a period of 15 days. On May 6, 2010, ARB submitted a Final Statement of Reasons and other necessary documents to the California Office of Administrative Law (OAL). The regulations were approved by OAL on June 17, 2010, and became effective on July 17, 2010.

The Fee Regulation establishes a fee schedule to support implementation of AB 32 by ARB and other State agencies. Funds collected are also used to repay loans appropriated by the Legislature and used by ARB and the California Environmental Protection Agency to pay for the first three fiscal years (FY) of the program, as shown in Table 1. These loans are required to be repaid with interest. The portion of the required revenue that is for loan repayment is estimated to be about $27 million per year for the first three years (FY 2010-2011 through FY 2012-2013). The remaining due in year four (FY 2013-2014), covers accrued loan interest, which, is expected to be substantially less than $27 million.

Table 1. AB 32 Loans

Fiscal Year	Loan Source	Loans* (in $Thousands)
FY 2007-2008	Motor Vehicle Account[1]	$15,472
FY 2008-2009	Beverage Container Recycling Fund[2]	$32,000
FY 2009-2010	Beverage Container Recycling Fund[3]	$35,000
Total		**$82,472**

*Does not include accrued interest.

[1] SB 77 (Ducheny, Chapter 171, Budget Act of 2007)
[2] AB 1781 (Laird, Chapter 268, Budget Act of 2008)
[3] SBX3 1 (Ducheny, Chapter 1, Budget Act of 2009)

Funds are deposited in the Air Pollution Control Fund and are made available upon appropriation by the Legislature.

ARB determines the fee amounts for each of the affected entities based on: 1) required revenue set in the FY budget approved by the Legislature and Governor to implement AB 32 and repay loans, and 2) metric tons of CO_2 ($MTCO_2$) determined from fuels and emissions data reported, using the fee calculation methodology described in the Fee Regulation.

A. Implementation Status

In April 2011, ARB sent out invoices for FY 2010-2011 to 284 fee payers based on the total required revenue of $62.1 million. This total includes both AB 32 implementation expenses for the FY 2010-2011 of $35.2 million and $26.9 million of repayment on program start-up loans. At the time of publication of this Staff Report, ARB is in the process of sending out invoices for FY 2011-2012 to 294 fee payers based on the total revenue requirement of $61 million. Revenue requirements are established by the California Budget Act.

B. Process to Develop Proposed Amendments

A public workshop was held on January 21, 2011, to solicit comments on the proposed amendments. The workshop notice was posted to ARB's website and emailed to subscribers of the climate change list serve. A copy of the workshop notice is contained in Appendix C of this Staff Report.

ARB staff received oral comments during the workshop. Three entities also submitted written comments after the workshop. These comments were reviewed by staff and considered in the draft proposed amendments. The proposed amendments to the Fee Regulation can be found in Appendix A of this Staff Report.

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II. Need for Amendments

This chapter describes the need for amendments to the Fee Regulation. The amendments to the Fee Regulation are necessary to conform requirements of the Fee Regulation to the Mandatory Reporting Regulation (MRR) and to clarify some provisions of the regulation based on experience gained from implementation of the fee.

In December 2010, the Board considered modifications to certain sections of the MRR. The proposed amendments to the MRR were implemented to conform the MRR to the U.S. Environmental Protection Agency's mandatory greenhouse gas (GHG) reporting requirements contained in 40 Code of Federal Regulations (CFR), part 98, and to support the proposed California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms Regulation (Cap-and-Trade Regulation). Entities subject to the MRR and those subject to the Fee Regulation must use the same Internet-based reporting tool to report all required data.

For many sectors, reporting pursuant to the MRR provides data to comply with the Fee Regulation; as such, data are reported only once to limit the administrative burden on regulated entities. In order for the data to be reported for both regulations simultaneously, in most cases, identical definitions are necessary for clarity. To conform definitions and reporting dates to the MRR, staff proposes to amend the Fee Regulation to ensure relevant language is as consistent as possible.

While most definitions in the proposed amendments to the Fee Regulation are identical to the MRR, some are different by necessity, due to specific distinctions between the two regulations. These proposed amendments to definitions include the phrase "(Fee Regulation only)."

MRR amendments are anticipated to be effective for the 2011 report year (reported in 2012). To conform to the MRR requirements, the proposed amendments to the Fee Regulation are different for reporting years 2008 through 2010, and for report years 2011 and later. This differentiation is necessary to reflect how the Fee Regulation determines fees based on the currently effective MRR and the amended MRR, which is scheduled to become legally effective in late 2011.

Staff expects these proposed amendments to the Fee Regulation to become legally effective prior to the 2011 report year due dates of April 1, 2012, for facilities and fuel suppliers and June 1, 2012, for electric power entities. This will ensure that the Fee Regulation's reporting requirements conform to the MRR requirements for emissions data reports beginning with the 2011 report year.

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III. Proposed Amendments

In this chapter, we provide plain language descriptions of the proposed amendments to the Fee Regulation and explain the rationale and necessity for the proposals. The regulation is codified in title 17, California Code of Regulations, sections 95200 to 95207. The listed sections include only those sections that are proposed to be amended, added, or deleted. Sections revised only due to renumbering are not listed here. Appendix A contains the proposed amendments to the Fee Regulation. The proposed changes are shown in underline and ~~strikeout~~ format.

The proposed amendments are not intended to revisit decisions previously approved by the Board. The proposed changes are technical in nature and do not significantly change applicability or the calculation of fees established by the Fee Regulation.

A. Applicability (section 95201) – Emission Sources Subject to the Fee

The types of entities subject to the Fee Regulation are not significantly changed by the proposed amendments to section 95201. The Fee Regulation applies to the following entities:

- Natural gas entities (gas utilities, pipeline owners and operators, and end users receiving natural gas from an interstate pipeline);
- Producers and importers of California gasoline, California Reformulated Gasoline Blendstock (CARBOB), and California diesel;
- Oil refineries;
- Cement manufacturers;
- Electricity producers and importers; and
- Facilities that combust coal, petroleum coke, catalyst coke, or refinery gas.

Limited changes to section 95201 "Applicability" are proposed to clarify who is subject to the Fee Regulation, and to conform to the MRR. The changes are as follows:

1. Establish a threshold for combustion or consumption of 100,000 therms of natural gas in a report year for end users that receive natural gas directly from an interstate pipeline.

   This change is proposed to exclude small sources that combust or consume natural gas received directly from an interstate pipeline. It was not ARB's intention to require reporting or apply the fee to small sources that are simply part of the operation of the pipeline.

   To determine an appropriate exemption threshold, staff applied the minimum fee amount in the Fee Regulation, fifty dollars ($50), found in 95205(a), to the amount of therms delivered to any interstate pipeline end user. Based on the total program expenditures of approximately $35.2 million in the

FY 2010/2011 State budget and estimated total emissions of 362 million $MTCO_2$, the amount of therms equating to a fee of $50 (rounded for administrative simplicity) is determined as follows:

$$\frac{\text{Total program expenditures (\$35.2 million)}}{\text{estimated emissions (362 MMTCO}_2\text{)}} = \$0.097/MTCO_2$$

$$\frac{\$50}{\$0.097/MTCO_2} = 515\ MTCO_2 \text{ emissions (natural gas)}$$

$$\frac{515\ MTCO_2 \text{ emissions (natural gas)}}{5.302\ KgCO_2/\text{therm emission factor}} * 1000\ KgCO_2 = 97{,}220 \text{ therms}$$

Based on the above analysis, we propose that those end users receiving natural gas from interstate pipelines that combust or consume less than 100,000 therms of natural gas per report year, should not report under the requirements of the Fee Regulation. Likewise, staff proposes that operators or owners of interstate pipelines do not need to report end users to which they deliver less than 100,000 therms per report year. Because the Fee Regulation prohibits ARB from collecting fees of $50 or less, this proposal is based on the fact that reporting would have no impact on the fees collected. As such, the reporting of less than 100,000 therms, delivered or received, would impose a cost and not provide a benefit.

2. Clarify that among electricity generating facilities (EGF) that deliver electricity in California, the fee applies only to a megawatt-hour (MWh) delivered from grid-dedicated, stand-alone EGFs. The proposed amendments have the effect of excluding each MWh delivered from cogeneration and self-generation facilities, from determination of a fee based on the generation of electricity. This is consistent with the current Fee Regulation. This modification to the regulatory language for first deliverers and the associated changes in definitions conform to changes in the MRR, and will further clarify fee applicability and simplify administration of the fee. As is the case with the current Fee Regulation, EGFs that are not grid-dedicated, stand-alone EGFs (for example, cogeneration and self-generation facilities), will continue to pay the fee directly or indirectly based on fuels used at the facility.

3. Exclude from fee liability any MWh of electricity generated at a grid-dedicated, stand-alone EGF that is not subject to reporting under the MRR. The current Fee Regulation excludes any EGF that emits less than 2,500 $MTCO_2$ per year. Based on changes in MRR, EGFs emitting less than 10,000 metric tons of CO_2 equivalent ($MTCO_2e$) would not be subject to MRR. This change is proposed to conform to the MRR and to maintain consistency with the existing Fee Regulation for the 2011 report year and subsequent years.

4. This amendment is proposed to clarify that direct delivery of renewable energy is not subject to the fee. Replacement electricity for variable renewable energy is reported pursuant to the MRR and must meet the requirements of the proposed Cap-and-Trade Regulation in order to reduce an electricity importer's compliance obligation.

5. Clarify applicability for kerosene-type jet-fuel; biodiesel; renewable diesel; biogas; biomass; and municipal solid waste.

   This amendment is proposed to clarify that kerosene-type jet-fuel is not subject to the fee unless it is used in an EGF, and that the renewable fuels and municipal solid waste are not subject to the Fee Regulation, without regard to use at an EGF.

B. Definitions (section 95202)

Numerous changes in the definitions section of the Fee Regulation are being proposed as part of the amendments. Changes include deleting definitions that are no longer applicable, adding new definitions, and amending existing definitions. While most definitions in the proposed amendments to the Fee Regulation are identical to the MRR, some are different, by necessity, due to specific distinctions between the two regulations. Section 95202 contains three definitions, Associated gas, Catalyst coke, and Petroleum coke followed by the phrase "(Fee Regulation only)" to demonstrate definitions that differ from the MRR. In the proposed amendments to the MRR, the amendments to the definitions for Associated gas, Catalyst coke, and Petroleum coke would not conform with the existing, established structure of the Fee Regulation. To maintain that there is no net change in the amount of fees that are collected, staff believes that these three definitions should differ in the Fee Regulation from the MRR, by necessity.

C. Calculation of Fees (section 95203)

Minor amendments are being proposed to the fee calculation methodology to ensure consistency with the proposed changes in the definitions. The proposed amendments to the Fee Regulation would result in different fee calculation procedures for report years 2008 through 2010, and those fee calculation procedures for report years 2011 and later. This differentiation in fee calculation procedures is necessary to reflect how the Fee Regulation determines fees based on the currently effective MRR and the amended MRR, which is scheduled to become effective in late 2011.

The proposed amendments to the Fee Regulation would result in different fee calculation procedures for report years 2008 through 2010, and those fee calculation procedures for report years 2011 and later. This differentiation in fee calculation procedures is necessary to reflect how the Fee Regulation determines fees based on the currently effective MRR and the amended MRR, which is scheduled to become legally effective in late 2011.

D. Reporting and Recordkeeping Requirements (section 95204)

Minor amendments are needed to the reporting and recordkeeping requirements to: 1) clarify administrative information such as a billing address and identification of an official responsible for payment for all facilities, fuel suppliers, and electric power entities subject to the Fee Regulation; and 2) conform to the MRR reporting due dates.

E. Payment and Collection (section 95205)

ARB staff proposes amendments to clarify that an entity must remit payment within 60 days of the date of a fee determination notice, rather than the date of receipt of a fee determination notice. This clarification is necessary because we do not have the ability to determine when an entity receives a fee determination notice.

F. Regulatory Alternatives

California Government Code section 11346.2 requires ARB to consider and evaluate reasonable alternatives to the proposed amendments to the Fee Regulation and provide reasons for rejecting those alternatives. This section discusses the alternative evaluated and provides the reasons why it was not included in the proposed rulemaking. No alternative considered by the agency would be more effective in carrying out the purpose for which the amendments to the Fee Regulation are proposed or would be as effective as or less burdensome to affected private parties than the proposed Fee Regulation amendments.

<u>No Changes to the AB 32 Cost of Implementation Fee</u>
A "no action" alternative means that the Fee Regulation would be substantially different than the MRR in a number of important ways.

This alternative was rejected as it would create confusion and inconsistencies for regulated entities in complying with the MRR and the Fee Regulation. Examples of inconsistencies include:

1) Applicability for EGFs, and importers and marketers of electricity in the current Fee Regulation reference subsections 95111(a)(1)(A); 95111(a)(2)(A); 95111(b)(2)(B); 95111(b)(2)(C); and 95111(b)(3)(N) in the MRR. In the amended MRR, these subsections either do not exist or no longer apply to the same reporting entities. Therefore, some reporting sectors subject to the existing Fee Regulation would no longer have to pay fees and this would not be clear unless the regulation was changed to conform with MRR.

2) Definitions such as asset controlling supplier, delivered electricity, and electricity importer in the Fee Regulation are not consistent with the amended MRR. Unless amended, this would create confusion in how these terms are used in the two regulations. All electricity sector reporting for the Fee Regulation is the same as

required under the MRR. To allow reporting pursuant to MRR to be used for the fee determination under the Fee Regulation and limit administrative burden to regulated entities, the definitions should be identical.

G. Rationale for Amendments

The following section explains in detail the rationale behind each of the proposed amendments to the Fee Regulation.

Applicability – Section 95201

95201(a)(1)(B) – This subsection is revised to clarify that the Fee Regulation does not apply to end users receiving less than 100,000 therms of natural gas directly from interstate pipelines. This change is made to exclude the reporting burden to very small operators that are expected to be excluded from fee payment because their bills would be less than $50 (rounded) per year.

95201(a)(1)(C) – This subsection is revised to clarify that owners and operators of interstate pipelines are not required to report end users to which they deliver less than 100,000 therms of natural gas. This change is made to eliminate the reporting burden for very small operators that are expected to be excluded later from fee payment because their bills would be less than $50 (rounded) per year.

95201(a)(4)(A) – This subsection is revised to clearly specify that the subsection applies to electricity that is delivered to California prior to January 1, 2011, and to reflect the newly defined term purchasing-selling entity. This change is required to clarify requirements prior to the 2011 report year.

95201(a)(4)(B) – This subsection is added to clarify which electricity entities are subject to the fee for electricity that is delivered to California on or after January 1, 2011. This addition clarifies that fees apply to electricity generated at grid-dedicated, stand-alone EGFs. By using this newly defined phrase, which limits application of the fee applied for electricity to specific facility types, it is no longer necessary to exclude electricity cogeneration and self-generation facilities as found in the existing Fee Regulation. These changes conform to changes in the MRR.

95201(a)(4)(B) 1. – This subsection is added to clarify that no fee shall be paid for any MWh of electricity that is not required to be reported under MRR. Revisions to the MRR will no longer require reporting by electricity facilities that emit less than 10,000 $MTCO_2e$, whereas the existing Fee Regulation requires that fees be paid by facilities that emit 2,500 or more $MTCO_2$ per year. The data collected by the revised MRR will no longer support application of the fee to these lower emitting facilities. This addition is required to clarify that no fees are required for energy generated by facilities not required to report under the MRR for the 2011 report year, and subsequent years.

95201(a)(4)(B) 2. – This subsection is added to clarify that electricity generated by renewable energy sources and replacement electricity for variable renewable resources are not subject to the fee, except that replacement electricity with an emission factor greater than the default emission factor is subject to the fee based on the difference between the replacement electricity's emission factor and the default emission factor. These additions are required to clarify that there is no fee liability for renewable energy and to conform with how replacement electricity is treated in the MRR.

95201(a)(5) – This subsection is revised to specify that only facilities that combust or consume coal; petroleum coke (Fee Regulation only); catalyst coke (Fee Regulation only); or refinery fuel gas and are subject to the verification requirements in section 95103 of the MRR, are also subject to the Fee Regulation. This change is required to maintain the current applicability threshold of 25,000 $MTCO_2$ in emissions and clarify that facilities subject to MRR and eligible for abbreviated reporting under MRR, are not subject to the Fee Regulation.

95201(b) – This subsection is revised to clarify the term jet fuel to mean kerosene-type jet fuel and that biodiesel and renewable diesel fuels are not subject to the Fee Regulation, including when used at an EGF. It was not ARB's intention to include renewable fuels, as applicable, to the Fee Regulation, even when used at an EGF.

95201(c) – This subsection is revised to clarify that the specified renewable fuels and municipal solid waste are not subject to the fee.

Definitions – Section 95202

Numerous definitions are proposed to be revised, added, or deleted in the Fee Regulation and are listed in Appendix B of this Staff Report. Definitions and sections revised only due to renumbering are not listed.

Most of the changes to definitions included in the proposed amendments are needed to ensure the Fee Regulation is identical to the MRR. In many cases, this is due to a specific definition's use in determining applicability or reporting requirements. For several reporting sectors, data used for fee determination for the Fee Regulation are reported pursuant to the MRR. The data are only reported once through a single reporting tool. Primary examples of such reporting sectors are the electricity sector and facilities that combust or consume fuels, such as coal or petroleum coke. To allow reporting pursuant to MRR to be used for fee determination under the Fee Regulation, the definitions should be identical. In these cases, the list in Appendix B will simply provide, "revised (added or deleted) for reporting consistency with MRR." In all other cases, a more detailed rationale for the proposed amendment is provided.

While most definitions in the proposed amended Fee Regulation that correspond with definitions in the MRR are identical, some are different, by necessity, due to specific distinctions between the two regulations. These proposed amendments to definitions include the phrase "(Fee Regulation only)."

Calculation of Fees – Section 95203

Minor amendments to the fee calculation methodology are needed to ensure consistency with the revised definitions and to clarify how fees will be determined for report years 2008 through 2010, as well as report years 2011 and later. The proposed amendments are described below.

95203(b) – The Common Carbon Cost is revised to reflect the newly defined terms "Electricity delivered in California;" "qualified export;" "petroleum coke (Fee Regulation only);" "catalyst coke (Fee Regulation only);" and "refinery fuel gas" and to include a formula to subtract emissions from qualified exports of electricity.

95203(d) – Subsection on the Fuel Emission Factors is revised to: 1) correct a typographical error where "95204...(d)(4 5)" should be shown as separate subsections; 2) include default emission factors for Coal Unspecified (Electrical Power) and Coal Unspecified (Other Industrial); 3) clarify the petroleum coke emission factor applies to petroleum coke (Fee Regulation only); and 4) clarify that gasoline and diesel fuels subject to the fee are the defined "California gasoline" and "California diesel fuel." These changes are required for clarity, and to include fuels that are reported as combusted or consumed in the 2008 and subsequent report years.

95203(e) – Subsection on the Electricity Fee Rate is revised to clarify that the section is specific to electricity delivered in California, and to clarify that the cost calculation for electricity delivered prior to January 1, 2011, will not change.

95203(f) – Subsection on the Electricity Fee Rate is added to clarify how electricity fee rates for both electricity delivered in California and qualified exports are determined and to clarify that the cost calculation for electricity delivered on or after January 1, 2011, will use emission factors published by ARB pursuant to MRR. This amendment is necessary to align with the MRR.

95203(f), reordered to (g) – Subsection on Emission Factors for Specified Sources is revised to specify calculation methods for report years 2008 through 2010, and to correct a typographical error that applies to electricity generating units/facilities.

95203(h) – Subsection on Emission Factors for Specified Sources is added to specify that emission factors will be obtained from those published on ARB's Mandatory Reporting website for report years 2011 and subsequent years.

95203(g), reordered to (i) – Subsection on Emission Factors for Asset-Controlling Suppliers is revised to specify reporting requirements for report years 2008 through 2010 and to reflect amended definitions.

95203(j) – Subsection on Emission Factors for Asset-Controlling Suppliers is added to specify that emission factors will be obtained from those published on ARB's Mandatory Reporting website for report years 2011 and subsequent years.

95203(h), reordered to (k) – Subsection on Fee Liability for Fuels is revised to clarify that the variable Fr_i is the fuel fee rate for the fuel.

95203(i), reordered to (l) – Subsection on Fee Liabilities for Facilities that Combust Coal, Petroleum Coke (Fee Regulation only), Catalyst Coke (Fee Regulation only), or Refinery Fuel Gas is revised to clarify that the variable Fr_i is the fuel fee rate for the fuel, and revised to reflect amended definitions.

95203(j), reordered to (m) – Subsection on Fee Liability for Electricity Delivered in California is revised to reflect amended definitions and to include a formula to subtract emissions from qualified exports of electricity.

Reporting and Recordkeeping Requirements – Section 95204

Minor amendments to reporting and recordkeeping requirements are proposed to clarify administrative information and to conform with MRR on reporting due dates. The proposed amendments are described below.

95204(b) is revised to reflect new definitions for reporting entity and fuel supplier.

95204(b)(2), reordered to (b)(1)(C) – This subsection is revised to add additional requirements for the reporting of a mailing address, billing address, and identification of an official responsible for payment.

This additional information is necessary to ensure an invoice for a fee liability is received by the appropriate official at the appropriate address and to ensure ARB can mail general information on the Fee Regulation to the appropriate mailing address.

95204(c)(3) – This subsection is added to conform reporting due dates for the Fee Regulation and the MRR to reduce administrative burden to regulated entities.

95204(d) is revised to ensure consistency in revised applicability and revised reporting requirements specific to natural gas.

95204(e) – This subsection has been amended to clarify that all producers and importers of California gasoline, CARBOB, or California diesel fuel, must report the total amount of each variety of fuel sold or supplied for use in California which they produced or imported. This is necessary to clarify the point in the fuel supply chain at which reporting is required.

95204(f) – This subsection has been amended to: 1) clarify that these entities are subject to the Fee Regulation only if they are subject to the verification requirements in Section 95103 of the MRR; 2) reflect amended definitions; and 3) clarify that emissions of gases that meet the definition of refinery fuel gas, but are the result of incomplete combustion of natural gas as a fuel or incomplete processing of natural gas as a feedstock, should not be reported. This is to clarify requirements and avoid double counting emissions as the fee has already been applied to the natural gas used as fuel or feedstock.

Payment and Collection – Section 95205

An amendment to this section is proposed to clarify when an entity must remit a payment.

95205 (b) – This subsection has been amended to clarify that an entity must remit payment to ARB within 60 days of the fee determination notice date, rather than within 60 days of the receipt of the fee determination notice. This is necessary as ARB has no method to determine when an entity receives a fee determination notice.

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IV. Environmental Impact Analysis

In this chapter, we describe the evaluation of environmental impacts and environmental justice impacts of the proposed amendments to the Fee Regulation.

A. Legal Requirements

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential adverse environmental impacts of proposed regulations. The Secretary of the Natural Resources Agency determined that ARB meets the criteria for a Certified State Regulatory Program (title 14, California Code of Regulations (CCR) section 15251 (d)), and certified ARB's program for the adoption of regulations.

Public Resources Code, Section 21080.5, allows public agencies with certified regulatory programs to prepare a plan or other written document in lieu of environmental impact reports or negative declarations, and include the documentation in the Initial Statement of Reasons. The 45-day public review period coincides with and is intrinsic to the Office of Administrative Law's requirement for public review. ARB will respond in writing to all significant comments that pertain to potential environmental impacts raised by the public during the public review period or at the Board hearing. These responses will be contained in the Final Statement of Reasons for the amended Fee Regulation.

B. Background and Proposed Project Description

The Fee Regulation assesses fees on sources of GHG emissions from the most widely used fossil fuels, including gasoline; diesel; coal; petroleum coke; catalyst coke; refinery fuel gas; and natural gas. The fee will also be assessed on non-combustion GHG process emissions from refineries and cement manufacturers. Finally, the fee is imposed on the GHG emissions associated with electricity generation (including imported electricity). Together, emissions from fuel combustion, refining and manufacturing process emissions, and electricity account for over 85 percent of California's GHG emissions.

Generally, the Fee Regulation pursues an "upstream" approach. A regulated entity would be assessed a fee for the GHG emissions from fuel that a covered entity introduces into commerce in California, or the direct GHG emissions as a result of an industrial process. The upstream approach minimizes the administrative burdens associated with the Fee Regulation since it decreases the number of entities that must pay fees, and simplifies the reporting needed to determine the fees.

One major goal of the Fee Regulation is to equitably impose fees on the widest possible spectrum of GHG sources in an administratively feasible manner. This cannot be done unless some type of administrative mechanism is used to impose a fee on upstream entities, which can then pass on the cost of the fee by increasing the cost of the fuel supplied to downstream entities.

Because the Fee Regulation applies to GHG emission sources based upon their reported emissions under the MRR, the two regulations are closely linked. The MRR has been amended to conform with the U.S. EPA's mandatory GHG reporting requirements contained in 40 Code of Federal Regulations, part 98. Additionally, the MRR has been amended to reflect reporting requirements of the State's proposed Cap-and-Trade Regulation. Because the MRR requires changes, the Fee Regulation must also be amended to ensure consistency in reporting and administration of the fee. The proposed changes are minimal and ARB expects that there will be limited impacts on the universe of fee payers.

Staff expects the proposed amendments to the Fee Regulation to take effect prior to the 2011 report year due date to ensure the MRR and the Fee Regulation are consistent for emission data reports beginning with the 2011 report year. Under the existing Fee Regulation, affected entities are required to report to ARB the quantity of fuels and GHG emissions subject to the fee each year, beginning with the 2008 report year.

The following regulatory sections are being amended:

- 95201 Applicability
- 95202 Definitions
- 95203 Calculation of Fees
- 95204 Reporting and Recordkeeping Requirements
- 95205 Payment and Collection

The proposed regulatory amendments would make requirements of the Fee Regulation consistent to those of the amended MRR requirements. The amendments would not change previous decisions made by the Board, but would improve clarity of the Fee Regulation. In addition, because the reporting requirements for EGFs change from 2,500 $MTCO_2$/year to 10,000 $MTCO_2e$/year in the MRR, some currently affected entities would no longer be subject to the Fee Regulation.

C. Environmental Impacts

Activities that are subject to CEQA are defined in Section 21065 of the CEQA Guidelines as a "project" as follows:

> § 21065. PROJECT
>
> "Project" means an activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and which is any of the following:
>
> (a) An activity directly undertaken by any public agency.

(b) An activity undertaken by a person which is supported, in whole or in part, through contracts, grants, subsidies, loans, or other forms of assistance from one or more public agencies.

(c) An activity that involves the issuance to a person of a lease, permit, license, certificate, or other entitlement for use by one or more public agencies.

Staff consulted the CEQA Guidelines' Initial Study Checklist to determine if adoption and implementation of the proposed amendments to the Fee Regulation could result in any potentially significant adverse environmental impact.

The proposed amendments to the Fee Regulation consist of administrative changes that add, revise, or delete definitions, and change or exclude emissions reporting requirements for some entities. These changes would not require nor be reasonably expected to elicit a compliance response from a covered entity that could result in a physical change to the environment, directly or indirectly. As the proposed amendments would not cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, they are not a project as defined by CEQA.

D. 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; Statutes of 1999, CH. 690; Government Code section 65040.12 (c)). On December 13, 2001, the Board approved Environmental Justice Policies and Actions that establish a framework for incorporating environmental justice into ARB's programs, and that would be consistent with the directives of State law. The policies, subsequently developed, apply to all communities in California.

Staff has determined that the proposed amendments to the Fee Regulation would not result in an adverse impact to air quality and would not result in an increase in exposure to pollutants. Adoption and implementation of amendments to the Fee Regulation will have no adverse impacts on environmental justice communities.

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V. Economic Impact Analysis

In this chapter, ARB staff provides an overview of the economic impacts of the proposed amendments to the Fee Regulation on affected entities. For information on the economic impacts of the Fee Regulation in general, to public and private entities, refer to the May 8, 2009, ARB staff report: Initial Statement of Reasons for Rulemaking, Proposed AB 32 Cost of Implementation Fee Regulation.

A. Economic Impacts Associated with Proposed Amendments to the Fee Regulation

Proposed amendments to the Fee Regulation, which are based on proposed amendments to the MRR, raise the reporting requirement threshold from 2,500 $MTCO_2$/year to 10,000 $MTCO_2e$/year for EGFs. The proposed amendments to the Fee Regulation will not result in a net change to the revenue collected. The number of EGFs with emissions greater than 2,500 $MTCO_2$/year but less than 10,000 $MTCO_2e$/year will vary over time. It is expected that approximately 20 to 25 EGFs, currently subject to the Fee Regulation, would no longer be required to report emissions through the MRR, and therefore would no longer be required to pay under the Fee Regulation. An estimated $26,000 (based on 2008 reported emissions), which would otherwise be paid by these facilities, will be redistributed among the approximately 131 remaining public and private fee payers, based on fuel and emissions reported data. As described below, the estimated average increase cost to a typical business is 0.04 percent. We expect most businesses will be able to absorb the increased cost and that the proposed regulation would not have a significant adverse economic impact directly affecting any representative private persons.

B. Annual Cost of the Proposed Amendments to the Fee Regulation

1. Estimated Cost to Businesses

Based on FY 2010-2011 invoicing, the impact of $26,000 redistributed among all other fee payers would range from approximately $0.03 to $2,200 per invoice. Examples of changes to fee payer's invoices are as follows:

- A facility originally invoiced $5 million would see an increase of $2,100.
- A facility originally invoiced $1 million would see an increase of $420.
- A facility originally invoiced $10,000 would see an increase of $4.

This represents an estimated average increased cost to a typical business of 0.04 percent. Such an increase is not expected to have a noticeable impact on jobs.

2. Estimated Cost to Public Agencies

The proposed amendments to the Fee Regulation will not result in significant additional cost to local, State, or federal agencies as the annual costs in net revenue collected from affected entities is not significantly affected by the proposed amendments.

Four local agencies, presently subject to the Fee Regulation, would save a collective $3,800 as a result of the adoption of the proposed amendments. The remaining government agencies, that serve as retail providers and marketers of imported electricity and are currently subject to the existing Fee Regulation (approximately 26 in total), would collectively pay an estimated $1,465 of additional fees, as a result of the proposed amendments. One State agency, the California Department of Water Resources, would be required to pay an additional estimated $85. In addition, the Western Area Power Administration, a federal agency, will pay an additional estimated $30. The proposed amendments will not result in any additional costs to the ARB to implement the Fee Regulation.

VI. References

Air Resources Board. AB 32 Cost of Implementation Fee. July 17, 2010. (ARB, 2010)

Air Resources Board. AB 32 Total Required Revenue: Funding Approved in the California Budget Act for Fiscal Year 2010-2011. June 24, 2011. (ARB, 2011)

Air Resources Board. Climate Change Scoping Plan: A Framework for Change; Pursuant to AB 32, The California Global Warming Solutions Act of 2006. December 2008. (ARB, 2008)

Air Resources Board. Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. January 1, 2009 (ARB, 2009)

Air Resources Board. Staff Report: Initial Statement of Reasons for Rulemaking, Proposed AB 32 Cost of Implementation Fee Regulation and Proposed Amendment to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. May 8, 2009. (ARB, 2009a)

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Appendix A

Proposed Amendments to the AB 32 Cost of Implementation Fee Regulation

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PROPOSED AMENDMENTS TO THE AB 32 COST OF IMPLEMENTATION FEE REGULATION

This appendix shows only amendments to the currently enacted AB 32 Cost of Implementation Fee Regulation (Article 3, sections 95200 to 95207, title 17, California Code of Regulations). The proposed amendments are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions. "[No change]" indicates that regulatory language not being amended is not shown.

Amend article 3, sections 95201 to 95205, title 17, California Code of Regulations to read as follows:

Article 3: Fees

Subarticle 1: AB 32 Cost of Implementation Fee Regulation

§ 95200. Purpose.

The purpose of this subarticle is to collect fees to be used to carry out the California Global Warming Solutions Act of 2006 (Stats. 2006; Ch. 488; Health and Safety Code sections 38500 *et seq.*), as provided in Health and Safety Code section 38597.

NOTE: Authority cited: Sections 38510, 38597, 39600 and 39601, Health and Safety Code. Reference: Sections 38530 and 39600, Health and Safety Code.

§ 95201. Applicability.

(a) This subarticle applies to the following entities. The terms used below are defined in section 95202.

(1) *Natural Gas Utilities, Users, and Pipeline Owners and Operators that distribute or use natural gas in California.*

(A) All public utility gas corporations and publicly owned natural gas utilities operating in California. Fees shall be paid for each therm of natural gas delivered to any end user in California, excluding natural gas delivered to electricity generating facilities.

(B) All owners and operators that are end users of natural gas received directly from interstate pipelines, except for electricity generating facilities and facilities that combust or consume less than 100,000 therms of natural gas received directly from an interstate pipeline in a reporting year. Fees shall be paid for each therm of natural gas directly ~~distributed~~delivered by interstate pipelines.

(C) All owners or operators of interstate pipelines that are not included in subsection 95201(a)(1)(A), and that ~~distribute~~deliver natural gas directly to end users in California. These entities are included for the purposes of reporting only. Each owner or operator shall report those end users in California to which they ~~supply natural gas~~ deliver 100,000 therms of natural gas or more in a reporting year.

(D) All owners or operators of interstate pipelines that are not included in subsection 95201(a)(1)(A), that ~~distribute~~deliver natural gas directly to end users. Fees shall be paid for each therm of nautral gas ~~distributed~~delivered directly to end users, except for natural gas delivered to electricity generating facilities.

(E) - (F) [No change]

(2) - (3) [No change]

(4) *First Deliverers of Electricity.*

(A) For electricity delivered in California prior to January 1, 2011, any~~Any~~ owner or operator of an electricity generating facility in California that delivers electricity to the California transmission and distribution system, ~~or~~ and any electricity importer that is the purchasing ~~or~~ selling entity that delivers electricity at its first point of delivery in California. Fees shall be paid for each megawatt-hour of net power generated by combustion of natural gas, coal or other fossil fuels (except California diesel) at an electricity generating facility in California~~)~~, and reported pursuant to section 95111(a)~~(1)(A) or 95111(a)(2)(A)~~ of the Mandatory Reporting Regulation. Fees shall also be paid for each megawatt-hour of imported electricity reported pursuant to section~~s~~ 95111(b)~~(2)(B and C) and 95111(b)(3)(N)~~ of the Mandatory Reporting Regulation if the electricity is from either unspecified sources or specified sources that combust natural gas, coal, petroleum coke, catalyst coke, refinery gas or other fossil fuels (except California diesel).

~~(B)~~ 1. No fee shall be paid for any megawatt-hour generated at any electricity generating facility that has a nameplate generating capacity of less than one megawatt, or that emits less than 2,500 metric tons of CO_2 from electricity generating activities during the reporting year.

~~(C)~~ 2. No fee shall be paid for any megawatt-hour of electricity generated at a cogeneration facility.

(B) For electricity delivered in California on or after January 1, 2011, any owner or operator of a grid-dedicated, stand-alone electricity generating facility in California that delivers electricity to the California transmission and distribution system, and any electricity importer that is the purchasing-selling entity that delivers electricity at its first point of delivery in California. Fees shall be paid for each megawatt-hour of net power generated by combustion of natural gas, coal or other fossil fuels (except California diesel) at a grid-dedicated, stand-alone electricity generating facility in California, and reported pursuant to section 95112 of the Mandatory Reporting Regulation. Fees shall also be paid for each megawatt-hour of imported electricity reported pursuant to section 95111 of the Mandatory Reporting Regulation if the electricity is from either unspecified sources or specified sources that combust natural gas, coal, or other fossil fuels (except California diesel). For multi-jurisdictional retail providers, fees shall be paid only for each megawatt-hour of wholesale sales delivered to a first point of delivery in California.

1. No fee shall be paid for any megawatt-hour of electricity that is not required to be reported pursuant to the Mandatory Reporting Regulation.

2. No fee shall be paid for any megawatt-hour of renewable energy, nor for replacement electricity for variable renewable resources that meets the requirements for a zero emission factor pursuant to MRR section 95111 except that, for replacement electricity that has an emission factor greater than the default emission factor, the fee shall be paid based on the difference between the greater emission factor and the default emission factor.

(5) *Facilities that Combust or Consume Coal, Petroleum Coke (Fee Regulation only), Catalyst Coke (Fee Regulation only) or Refinery Fuel Gas.*

Any owner or operator of a facility in California, except for electricity generating facilities, that is subject to verification requirements in Section 95103 of the Mandatory Reporting Regulation, and combusts as fuel or consumes as feedstock any of the following substances:

(A) Coal;

(B) Petroleum coke (Fee Regulation only);

For coal and petroleum coke (Fee Regulation only), fees shall be paid on the annual quantity of emissions as calculated pursuant to 95203(i).

(C) Catalyst coke (Fee Regulation only); or

(D) Refinery fuel gas.

For catalyst coke (Fee Regulation only) or refinery fuel gas, fees shall be paid on the reported emissions.

(b) This subarticle does not apply to any of the following fuels, or to emissions resulting from combustion of any of the following fuels, unless said fuels are used at electricity generating facilities:
(1) aviation gasoline;
(2) kerosene type jet fuel;
(3) kerosene;
(4) liquefied petroleum gas;
~~(5) biodiesel;~~
~~(6) renewable diesel;~~
(~~7~~ 5) residual fuel oil;
(~~8~~ 6) propane; or
(~~9~~ 7) any fuel exported for use outside of California.

(c) This subarticle does not apply to any of the following fuels, or to emissions resulting from combustion of any of the following fuels.
1. biodiesel;
2. renewable diesel;
3. biomass;
4. biogas; or
5. municipal solid waste.

(~~c~~ d) The fees associated with this subarticle shall be based upon the reported data from the most recent calendar year for which the mandatory reporting data verification process is completed, except for fiscal year 2010/2011. 2008 calendar year data shall be used for fiscal year 2010/2011.

NOTE: Authority: Sections 38510, 38597, 39600 and 39601, Health and Safety Code. Reference: Sections 38501, 38505 and 39300, Health and Safety Code.

§ 95202. Definitions.

(a) For the purposes of this subarticle, the following definitions shall apply:

(1) "AB 32" means the California Global Warming Solutions Act of 2006, Assembly Bill 32, Chapter 488, Statutes of 2006, as codified in Health and Safety Code section 38500 *et seq.*

(2) "Acid gas reagent" means a substance used to chemically remove acid gases from industrial exhaust streams.

(3) "Acid gas scrubbers" mean a diverse group of air pollution control devices that can be used to remove some particulates and/or gases from industrial exhaust streams.

(4) "Annual" means with a frequency of once a year; unless otherwise noted, annual events, such as reporting requirements, ~~the fee payment and liability~~ will be based on the calendar year.

(5) "ARB" or "Board" means the California Air Resources Board.

(6) "Asset-controlling supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier-specific identification number and specified source emission factor by ARB for the wholesale electricity procured from its system and imported into California. Bonneville Power Administration (BPA) is recognized by ARB as an asset-controlling supplier.~~for its fleet of generating facilities under the provisions of subarticle 2, title17 of the California Code of Regulations.~~

~~(7) "Asset-owning supplier" means any entity that owns electricity generating facilities that deliver electricity to a transmission or distribution line, and is assigned a supplier-specific identification number for its fleet of generating facilities under the provisions of article 2, title 17 of the California Code of Regulations.~~

(~~8~~ 7) "Associated gas (Fee Regulation only)" means ~~hydrocarbon-based gaseous~~a natural gas fuel produced in association with crude oil from any oil well and subsequently burned in the field as a fuel.

(8) "Aviation gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910–07a, Standard Specification for Aviation Gasolines, which is incorporated by reference herein.

(9) "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.

(10) "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.

(~~9~~ 11) "Billing address" means the address where the party responsible for payment would receive an invoice.

(12) "Bigeneration unit" means a unit that simultaneously generates electricity and useful thermal energy from the same fuel source but without waste heat recovery. An example of bigeneration includes a boiler generating steam that is split into two streams, and one stream powers a steam turbine to generate electricity, while the other stream is used for other industrial, commercial, or heating and cooling purposes that are not in support of or a part of the electricity generation system.

(~~10~~ 13) "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~~meeting~~ all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under title 40, Code of Federal Regulations, 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*) which is incorporated by reference herein;

(D) Intended for use in engines that are designated to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(~~11~~ 14)"Biogas" (also called biomethane) means gas that is produced from the breakdown of organic material in the absence of oxygen. Biogas is produced in processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical 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.

(15) "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, 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 subarticle, biomass includes both California Renewables Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

(~~12~~ 16)"Busbar" means ~~the~~a power conduit of a~~n~~ facility with electricity generating ~~facility~~units that serves as the starting point for the electricity transmission ~~and distribution~~ system.

(~~13~~ 17)"Calendar year" means the time period from January 1 through December 31.

(~~14~~ 18)"California gasoline" has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

For California gasoline,

(A) "Produce" for California gasoline has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(B) "Producer" for California gasoline has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(C) "Supply" for California gasoline has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(D) "Importer" for California gasoline means the majority owner of the California gasoline when it first enters the ~~s~~State of California. For rail cars, cargo tanks, and pipelines, it is the point where the product first crosses the California State border. For imports by marine vessel it is the point where the fuel leaves the vessel.

(E) "Import" for California gasoline means movement of California gasoline into the ~~s~~State of California. For rail cars, cargo tanks, and pipelines it is when the product first crosses the California State border. For imports by marine vessel, it is the point where the fuel leaves the vessel.

(~~15~~ 19)"California reformulated gasoline blendstock for oxygenate blending," or "CARBOB," has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

For CARBOB,

(A) "Produce" for CARBOB has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(B) "Producer" for CARBOB has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(C) "Supply" for CARBOB has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(D) "Importer" for CARBOB means the majority owner of the CARBOB when it first enters the ~~s~~State of California. For rail cars, cargo tanks, and pipelines it is the point where the product first crosses the California State border. For imports by marine vessel it is the point where the fuel leaves the vessel.

(E) "Import" for CARBOB means movement of CARBOB into the ~~s~~State of California. For rail cars, cargo tanks, and pipelines it is when the product first crosses the California ~~s~~State border. For imports by marine vessel it is the point where the fuel leaves the vessel.

(~~16~~ 20)"California diesel fuel" has the same meaning as "Vehicular Diesel Fuel," as defined in title13 California Code of Regulations, section 2282(b).

For California diesel fuel,

(A) "Produce" for California diesel fuel has the same meaning as "Vehicular Diesel Fuel," as defined in title 13 of the California Code of Regulations, section 2282(b).

(B) "Producer" for California diesel fuel has the same meaning as "Vehicular Diesel Fuel," as defined in title 13 of the California Code of Regulations, section 2282(b).

(C) "Supply" for California diesel fuel has the same meaning as defined in title 13 of the California Code of Regulations, section 2282(b).

(D) "Importer" for California diesel fuel means the majority owner of the California diesel fuel when it first enters the ~~s~~State of California. For rail cars, cargo tanks, and pipelines it is the point where the product first crosses the California ~~s~~State border. For

imports by marine vessel it is the point where the fuel leaves the vessel.

(E) "Import" for California diesel fuel means movement of product into the ~~s~~State of California. For rail cars, cargo tanks, and pipelines it is when the product first crosses the California ~~s~~State border. For imports by marine vessel it is the point where the fuel leaves the vessel.

(~~17~~ 21)"Carbon dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(~~18~~ 22) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e"~~"CO_2E" or "CO_2 equivalent"~~ means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas. ~~a measure for comparing carbon dioxide with other greenhouse gases, based on the quantity of those gases multiplied by the appropriate global warming potential factor and commonly expressed as metric tons of carbon dioxide equivalents ($MTCO_2E$).~~

(~~19~~ 23)"Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

(~~20~~ 24)"Catalyst coke (Fee Regulation only)" means carbon that is deposited on a catalyst, thus deactivating the catalyst.

(~~21~~ 25)"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.

(~~22~~ 26)"Cement manufacturer" means an owner or operator of a cement plant.

(~~23~~ 27)"Cement plant" means an industrial structure, installation, plant or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, or other hydraulic cements, and typically identified by North American Industry Classification System Code 327310.

(~~24~~ 28)"Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(~~25~~ 29)"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"~~.~~ (September 2005), which is incorporated by reference herein.

(30) "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 and 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.

(~~26~~ 31)"Cogeneration facility" means an industrial structure, installation, plant, or building or self-generation facility, which may include one or more cogeneration ~~systems~~units configured as either a topping cycling or bottoming cycling plant~~, and in which electricity is generated solely from cogeneration systems~~.

(~~27~~ 32)"Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential or simultaneous generation of multiple forms of useful energy, one of which must be electricity, and~~(usually electrical and thermal),~~ at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

(33) "Cogeneration unit" means a unit 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 and waste heat recovery.

(~~28~~ 34)"Combust" means the process of burning or setting fire to a fuel.

(~~29~~ 35)"Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(36) "Consumption" means to use, decay or destruct.

(37) "Consumed on-site" means to consume at a facility.

(~~30~~ 38) "Cracking" means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

(~~31~~ 39)"Debt" means those loans obtained by the Board, and required by the Legislature to be repaid, to carry out AB 32 for fiscal years 2007/2008, 2008/2009, and 2009/2010.

(~~32~~ 40)"Delivered electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed. ~~is delivered to a point of interconnection with the California electricity transmission and distribution system. For electricity that is generated in California, the electricity is delivered from a specified source at the busbar. For electricity generated outside California from specified or unspecified sources, the electricity is delivered to a point of delivery in California for consumption in California.~~

(41) "EIA" means the Energy Information Administration. The EIA is a statistical agency of the United States Department of Energy.

(42) "Electricity delivered in California" means electricity that is delivered to a point of interconnection with the California electricity transmission and distribution systems. For electricity that is generated in California, the electricity is delivered from a specified source at the busbar. For electricity generated outside California from specified or unspecified sources, the electricity is delivered to a point of delivery in California for consumption in California.

(~~33~~ 43)"Electricity ~~F~~fee ~~R~~rate" means the rate charged per megawatt-hour (MWh) of electricity generated at a specified source based on a specified source's emission factor, or generated at unspecified sources and based on the ~~or an unspecified source based on source specific emission factors, or a~~ default emission factor for unspecified sources.

(~~34~~ 44)"Electricity generating facility" ~~or "Generating facility"~~ means a facility that generates electricity and includes one or more generating units at the same location. ~~inside or outside California. "Electric generating facility" or "Generating facility" does not include a cogeneration facility or a self-generation facility.~~

(45) "Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion

turbine(s), or other prime mover(s) operated together to produce electric power.

(~~35~~ 46)"Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on 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. 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). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB. ~~means an owner of electricity generated outside of California as it is delivered to the first point of delivery in California, for electricity having a final point of delivery in California.~~

(~~36~~ 47)"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.

(~~37~~ 48)"Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or fuel supplier each year and submitted by electronic means to ARB that provides the information required by the Mandatory Reporting Regulation and to comply with this subarticle.

(~~38~~ 49)"Emission factor" means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity (e.g., metric tons of carbon dioxide emitted per gallon of gasoline burned).

(~~39~~ 50)"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 or combustion. ~~the entity to which natural gas is delivered for combustion or consumption.~~

(~~40~~ 51)"Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, government agency, or public district.

(~~41~~ 52) "Exclusive marketer" means a marketer that has exclusive rights to market electricity for a generating facility or group of generating facilities.

(~~42~~ 53) "Executive Officer" means the Executive Officer of ~~ARB~~ the California Air Resources Board, or his or her delegate.

(~~43~~ 54)"Facility" means any physical property, plant, building, structure, ~~stationary~~ source, or stationary equipment ~~or grouping of stationary equipment or stationary sources~~ 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 ~~operational~~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.

(~~44~~ 55)"Fee determination notice" means the notice or invoice provided by ARB to entities regulated by this subarticle stating the dollar amount due.

(~~45~~ 56)"Feedstock" means the raw material supplied to a process.

(~~46~~ 57)"First deliverer of electricity" means either the owner or operator of an electricity generating facility in California, or an electricity importer.

(~~47~~ 58)"Fiscal year" means the time period from July 1 to June 30.

(~~48~~ 59)"Fossil fuel" means ~~a fuel, including but not limited to coal, oil,~~ natural gas, ~~and~~ petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material. ~~by-products, produced by the decomposition of ancient (fossilized) plants and animals.~~

(~~49~~ 60)"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.

(~~50~~ 61)"Fuel fee rate" means the rate charged per $MTCO_2$ produced by greenhouse gas sources specific to the fuel combusted and calculated by ARB.

(62) "Fuel supplier" means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas, or a supplier of liquid petroleum gas as specified in the Mandatory Reporting Regulation.

(~~51~~ 63)"Gallon" means the United States gallon of 231 cubic inches or the volumetric gallon adjusted to 60 degrees Fahrenheit when the invoice and settlement is made on the temperature corrected gallonage.

(64) "Generated electricity" means electricity generated by an electricity generating unit at the reporting facility. Generated electricity does not include any electricity wheeled through the facility, i.e., electricity that is generated outside the facility and delivered into the facility with final destination outside of the facility.

(~~52~~ 65)"Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(~~53~~ 66)"Global warming potential" or "GWP ~~factor~~" 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. ~~radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.~~

(~~54~~ 67)"Government agency" means any agency as defined in Government Code section 11000.

(~~55~~ 68)"Greenhouse gas source" means any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(69) "Grid" or "electric power grid" means a system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or more control centers.

(70) "Grid-dedicated facility" means an electricity generating facility in which all net power generated is destined for distribution on the grid through retail providers or electricity marketers, ultimately serving wholesale or retail customers of the grid.

(71) "Gross generation" or "gross power generated" means the total electrical output of the generating facility or unit, expressed in megawatt hours (MWh) per year.

(~~56~~ 72)"Imported electricity" means electricity ~~that is~~ generated outside the State of California and delivered to ~~a first point of delivery into~~ serve load inside the State of California. Imported electricity includes electricity delivered from a 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 California over a 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, which is electricity that is delivered into California with final point of delivery outside California. ~~with a final point of delivery in California. Imported electricity does not include:~~

~~(A) Power wheeled through California, which is power that is imported into California that terminates in a location outside of California; or~~

~~(B) Power transactions in which imported power is simultaneously exchanged for exported power.~~

(~~57~~ 73)"Interstate ~~P~~pipeline" means any entity ~~engaged in~~that owns or operates a natural gas ~~transportation~~pipeline delivering natural gas to consumers in the State and is subject to ~~the jurisdiction of~~rate regulation by the Federal Energy Regulatory Commission. ~~(FERC) under the Natural Gas Act.~~

(~~58~~ 74)"Intrastate ~~P~~pipeline" means ~~a natural gas pipeline that operates wholly in California.~~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.

(~~59~~ 75)"Kerosene" ~~means~~ is a light petroleum distillate ~~fuel that includes~~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. ~~that have properties similar to those of No. 1 fuel oil.~~

(76) "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.

(77) "Linked jurisdiction" means a jurisdiction which has entered into a linkage agreement pursuant to subarticle 12 of the Cap-and-Trade Regulation[1].

(~~60~~ 78)"Liquefied petroleum gas ~~(LPG)~~" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG can be mixtures of primarily propane, primarily butane, or mixtures of propane or butane. LPG includes 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 LGP, GLP, LP-Gas and propane.~~normal butane, isobutane, propane, or butylene (including isomers) or mixtures composed predominantly thereof in liquid or gaseous state having a vapor pressure in excess of 40 pounds per square inch absolute at a temperature of 100 degrees Fahrenheit.~~

(79) "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.

(~~61~~ 80)"Mandatory Reporting Regulation" 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).

(~~62~~ 81)"Marketer" means a purchasing~~-~~/selling entity that takes title to wholesale electricity and is not a retail provider.~~, and that is the purchaser/seller at the first point of delivery in California for electric power imported into California, or the last point of receipt in California for power exported from California.~~

(~~63~~ 82)"Megawatt hour" or "MWh" means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

(~~64~~ 83)"Meter" means a device designed to measure, record or regulate the amount or volume of the flow of a gas.

(~~65~~ 84)"Metric ton" or "MT" ~~or "tonne"~~ means a common international measurement for ~~the quantity of greenhouse gas emissions~~mass, equivalent to ~~about~~ 2204.6 pounds or 1.1 short tons.

(85) "MMBtu" means million British thermal units.

[1]California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms Regulation, title 17, California Code of Regulations, sections 95800 to 96022.

(~~66~~ 86)"Motor vehicle" has the same meaning as defined in section 415 of the Vehicle Code.

(87) "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.

(88) "Municipal Solid Waste" 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.

(~~67~~ 89)"Nameplate generating capacity" means the maximum rated output of a generator under specific conditions ~~designed~~designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in Kilowatts (kW) on a nameplate physically attached to the generator.

(~~68~~ 90)"Natural gas" means a naturally occurring mixture of hydrocarbons and non-hydrocarbon gases found in geologic formations beneath the ~~E~~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 subarticle, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.~~that~~

~~maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. "Natural gas" does not include "biogas".~~

(~~69~~ 91)"Natural gas importer" means any entity that receives natural gas from a party that is not a public gas corporation, as defined in this subarticle, that consumes and/or distributes natural gas to consumers of natural gas.

(92) "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.

(~~70~~ 93)"Net generation" or "Net power generated" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(~~71~~ 94)"Operational control" for a facility subject to this subarticle means the ~~entity that has~~ 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 subarticle.

(~~72~~ 95)"Operator" means the entity, including an owner, having operational control of a facility. 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.

(~~73~~ 96)"Owner" means the entity having title ~~of~~to the property or assets which are subject to the fee.

(97) "Oxygenate" is any oxygen-containing, ashless, organic compound, such as an alcohol or ether, which, when added to gasoline, increases the amount of oxygen in gasoline.

(~~74~~ 98)"Payment period" means 60 days from the ~~receipt of the billing~~invoice date, as stated in section 95205, each calendar year.

(~~75~~ 99)"Petroleum coke (Fee Regulation only)" means a solid residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking.

(~~76~~ 100)"Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, ~~aromatics,~~ gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt~~, or other products~~ (bitumen) through distillation of petroleum or through redistillation, cracking, ~~rearrangement~~ 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.

(~~77~~ 101)"Point of delivery" means the point on an ~~electric~~ electricity transmission or distribution system where a ~~power supplier delivers~~deliverer makes electricity available to a receiver, or available to serve load.~~of that energy.~~ 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.

(~~78~~ 102)"Power" means electricity, except where the context makes clear that another meaning is intended.

(~~79~~ 103)"Process" means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(~~80~~ 104)"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.

~~(A) For cement manufacturing: The greenhouse gas emissions produced through the chemical reactions of feedstock during pyroprocessing to produce cement clinker (which does not include greenhouse gas emissions which are the result of fuel combustion emissions).~~

~~(B) For refineries and hydrogen plants: the greenhouse gas emissions resulting from the steam methane reforming process excluding those that occur as a result of the use of natural gas as a feedstock.~~

(105) "Produced on-site" means produced at a facility.

~~(81) "Producer" means any person who owns, leases, operates, controls or supervises a California production facility.~~

~~(82) "Production facility" means a facility in California at which gasoline or CARBOB is produced. Upon request of a producer, the Executive Officer may designate, as part of the producer's production facility, a physically separate bulk storage facility which (A) is owned or leased by the producer, and (B) is operated by or at the direction of the producer, and (C) is not used to store or distribute gasoline or CARBOB that is not supplied from the production facility.~~

(~~83~~ 106)"Propane" ~~means~~is a paraffinic hydrocarbon with molecular ~~normally straight chain hydrocarbon that boils at -3.67 degrees Fahrenheit and is represented by the chemical~~ formula C_3H_8.

(~~84~~ 107)"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.

(~~85~~ 108)"Public utility gas corporation" means a gas corporation as defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(~~86~~ 109)"Purchasing ~~or~~ selling entity" or "PSE" means ~~for purposes of this regulation an~~the functional entity that ~~is eligible to~~ purchases or sells, and takes title to energy, ~~or~~ capacity, and ~~reserve transmission~~ reliability related services. A PSE is identified on a NERC E-tag for each physical path segment.

(110) "Qualified exports" means emissions associated with electricity that is exported in the same hour as imported electricity and documented by NERC E-tags. Only electricity exported within the same hour and by the same PSE as the imported electricity is a qualified export. It is not necessary for the imported and exported electricity to enter or leave California at the same intertie. Emissions associated with qualified exports may be subtracted from the associated imports. Qualified exports shall not result in a negative compliance obligation for any hour.

(111) "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.

(~~87~~ 112)"Refinery fuel gas" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas~~.~~ or used as a chemical feedstock.

(~~88~~ 113)"Renewable diesel" means a motor vehicle fuel or fuel additive ~~which~~that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;

(B) Not a mono-alkyl ester;

(C) Intended for use in engines that are designed to run on conventional diesel fuel; and

(D) Derived from nonpetroleum renewable resources.

(114) "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.

(115) "Replacement electricity" means electricity delivered to a first point of delivery in California to replace electricity from variable renewable resources in order to meet hourly load requirements. The electricity generated by the variable renewable energy facility and purchased by the first deliverer is not required to meet direct delivery requirements. The physical location of the variable renewable energy facility busbar and the first point of receipt on the NERC E-tag for the replacement electricity must be located in the same balancing authority area.

(116) "Reporting entity" means a facility owner or operator, fuel supplier, or electricity importer subject to the requirements of this subarticle.

(~~89~~ 117)"Report Year" or "Reporting Year" means the calendar year for which emissions are being reported in the emissions data report.

(~~90~~ 118)"Residual fuel oil" means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.

(~~91~~ 119)"Retail provider" means an entity that provides electricity to retail end users in California and is an electric 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 subarticle, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(~~92~~ 120)"Self-generation facility" means a facility dedicated to serving a particular electricity end user, usually located on the user's premises. The facility may either be owned directly by the electricity user or owned by an entity with a contractual arrangement to provide electricity to meet some or all of the user's load.

(121) "Short ton" or "Ton" means a common international measurement for mass, equivalent to 2,000 pounds.

(~~93~~ 122)"Source" means greenhouse gas source~~.~~, any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(~~94~~ 123)"Specified source of electricity" or "specified source ~~of power~~" means a ~~particular generating~~facility or unit ~~or~~which is permitted to be claimed as the source of imported electricity delivered by an electricity importer. The electricity importer must have either full or partial ownership in the facility/unit or a written contract 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 the ARB.~~electricity generating facility in California or out of state to which electrical generation can be confidently tracked due to full or partial ownership by a first deliverer, or due to its identification in a power contract with a first deliverer, and also means an asset-owning or asset-controlling supplier.~~

(124) "Stand-alone electricity generating facility" means an electricity generating facility whose primary business and sole industrial operation is electricity generation, and is not a cogeneration or bigeneration facility.

(~~95~~ 125)"Stationary" means neither portable nor self propelled, and operated at a single facility.

(~~96~~ 126)"Steam methane reforming process" means a method in which high temperature steam is used to produce hydrogen from a methane source.

(127) "Substitute power" or "substitute electricity" means electricity that is provided to meet the terms of a power purchase contract with a specified facility or unit when that facility or unit is not generating electricity.

(~~97~~ 128)"Therm" means a unit of heat equal to 100,000 British thermal units (1.054×10^8 joules).

(129) "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.

~~(98) "Ton" means a short ton equal to 2000 pounds.~~

(~~99~~ 130)"Unspecified source of electricity~~power~~" or "unspecified source" means ~~a source of~~ electricity generation that cannot be matched to a ~~particular~~specific facility or unit that generates electricity or matched ~~generating unit or facility, or~~ to an ~~asset owning or~~ asset-controlling supplier. recognized by the ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.

(131) "Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(132) "Variable renewable resource" means run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements.

(133) "Wholesale sales" in the context of delivered electricity, means sales for resale.

NOTE: Authority cited: Section 38510, 38597, 39600 and 39601, Health and Safety Code. Reference: Sections 38530, 39600 and 39601, Health and Safety Code.

§ 95203. Calculation of Fees.

(a) [No change]

(b) *Common Carbon Cost.*

The Executive Officer shall calculate a Common Carbon Cost (CCC), which represents the annual cost per $MTCO_2$ emitted. The CCC shall be calculated in accordance with the following formula:

$$CCC = \frac{TRR}{(Q_c \times EF_c) + Q_{cc} + Q_{rga} + (Q_{ng} \times EF_{ng}) + (Q_{ag}) + (Q_g \times EF_g) + (Q_d \times EF_d) + (Q_{je} \times EF_{je}) + Q_{pe}}$$

Where

TRR = Total Required Revenue, as specified in subsection 95203(a).

$(Q_c \times EF_c)$ = Statewide quantity of emissions from coal, or petroleum coke (Fee Regulation only), except that used in an electricity generating facility, calculated as the sum of:

$(Q_b \times EF_b)$ = Quantity of bituminous coal (Q_b) x emission factor for bituminous coal (EF_b);

$(Q_l \times EF_l)$ = Quantity of lignite coal (Q_l) x the emission factor (EF_l) for lignite coal;

$(Q_a \times EF_a)$ = Quantity of anthracite coal (Q_a) x the emission factor (EF_a) for anthracite coal;

$(Q_{sb} \times EF_{sb})$ = Quantity of subbituminous coal (Q_{sb})x the emission factor (EF_{sb}) for subbituminous coal;

$(Q_{pc} \times EF_{pc})$ = Quantity of petroleum coke (Fee Regulation only) (Q_{pc}) x the emission factor (EF_{pc}) for petroleum coke (Fee Regulation only)

Q_{cc} = Statewide quantity of emissions from catalyst coke (Fee Regulation only), except that used in an electricity generating facility

Q_{rga} = Statewide adjusted quantity of emissions from refinery fuel gas, except that used in an electricity generating facility

Q_{ng} = Statewide quantity, in therms, of natural gas supplied for all uses except electricity generating facilities during the reporting period

EF_{ng} = Emission factor of $MTCO_2$ for natural gas

Q_{ag} = Statewide quantity of emissions from associated gas (Fee Regulation only)

Q_g = Statewide quantity of gasoline supplied during the reporting period. This is the volumetric sum of California gasoline produced or imported into California and the amount of finished CARBOB product produced or imported into California. The finished CARBOB product is calculated as the volume sum of the CARBOB plus the maximum amount of oxygenate designated for each volume of CARBOB.

EF_g = Emission factor of $MTCO_2$ for each supplied gallon of California gasoline.

Q_d = Quantity of California diesel fuel supplied during the reporting period

EF_d = Emission factor of $MTCO_2$ for each supplied gallon of California diesel fuel

$(Q_{je} \times EF_{je})$ = Quantity of emissions from ~~delivered~~ electricity delivered in California as the sum of:

$(Q_{sp} \times EF_{sp})$ = Quantity of MWh of electricity delivered from each specified source multiplied by the emission factor for that specified source;

$(Q_{usp} \times EF_{usp})$ = Statewide quantity of MWh of electricity delivered from unspecified sources multiplied by the default emission factor for unspecified sources.

Minus
$(Q_{ge} \times EF_{ge})$ = Quantity of MWh of qualified exports from each specified source multiplied by the emission factor for that specified source.

Q_{pe} = Quantity of process emissions from cement manufacturing.

(c) *Fuel Fee Rate.*

For entities reporting pursuant to section 95204(d)(1), (d)(2), (d)(3), (d)(5), (e), and (f)(1), and (f)(2) the Executive Officer shall calculate a fuel fee rate for each fuel included in subsection 95203(b) using the following formula:

$FR_i = CCC \times EF_i$

Where:

FR_i = Fuel fee rate for the fuel

CCC = Common Carbon Cost

EF_i = Emission factor of $MTCO_2$ for each unit of fuel supplied.

(d) *Fuel Emission Factors.*

For entities reporting pursuant to section 95204(d)(1), (d)(2), (d)(3), (d)(4), (d)(5), (e), (f)(1) and (f)(2) the Executive Officer shall calculate the Common Carbon Cost and the Fuel fee rates using the following emissions factors:

Fuel Type	*CO_2 Emission Factor*	*Emission Factor Units*
Coal		
Anthracite	2,597.94	kg CO_2 / short ton
Bituminous	2,328.35	kg CO_2 / short ton
Sub-bituminous	1,673.64	kg CO_2 / short ton
Lignite	1,369.32	kg CO_2 / short ton
Unspecified (Electric Power)	1,884.86	kg CO_2 / short ton
Unspecified (Other Industrial)	2,082.89	kg CO_2 / short ton
Petroleum coke (Fee Regulation only)	2,530.65	kg CO_2 / short ton
Natural Gas	5.302	kg CO_2 / therm
California Diesel Fuel	9.96	kg CO_2 / gallon
California Gasoline	8.55	kg CO_2 / gallon

(e) *Electricity Fee Rate for electricity delivered in California prior to January 1, 2011.*

The Executive Officer shall calculate an Electricity Fee Rate for each source of electricity delivered in California using the following formulas:

$EFR_{sp} = CCC \times EF_{sp}$
$EFR_{asp} = CCC \times EF_{asp}$
$EFR_{usp} = CCC \times EF_{usp}$

Where:

"sp" denotes a specified source that is an electricity generating facility or unit

"asp" denotes an ~~asset-owning or~~ asset-controlling supplier

"usp" denotes an unspecified source

EFR_{sp} =The Electricity fee rate for the specified source

EFR_{asp} = The Electricity fee rate for the ~~asset-owning and~~ asset-controlling suppliers

EFR_{usp} = The Electricity fee rate for unspecified sources

EF_{sp} = Emission factor for specified source in $MTCO_2$ per MWh

EF_{asp} = Emission factor for ~~asset-owning and~~ asset-controlling suppliers in $MTCO_2$ per MWh

EF_{usp} = .499 $MTCO_2$ per MWh, the default Emission Factor for unspecified sources.

(f) *Electricity Fee Rate for electricity delivered in California on or after January 1, 2011.*

The Executive Officer shall calculate an Electricity Fee Rate for each source of electricity delivered, and for qualified exports, in California using the following formulas:

$EFR_{sp} = CCC \times EF_{sp}$
$EFR_{asp} = CCC \times EF_{asp}$
$EFR_{unsp} = CCC \times EF_{unsp}$

Where:

"sp" denotes a specified source that is an electricity generating facility or unit

"asp" denotes an asset-controlling supplier

"unsp" denotes an unspecified source

EFR_{sp} = The Electricity fee rate for the specified source

EFR_{asp} = The Electricity fee rate for the asset-controlling suppliers

EFR_{unsp} = The Electricity fee rate for unspecified sources

EF_{sp} = Emission factor for specified source in $MTCO_2e$ per MWh

EF_{asp} = Emission factor for asset-controlling suppliers in $MTCO_2e$ per MWh

EF_{unsp} = Default emission factor for unspecified electricity imports for first points of receipt located in nonlinked jurisdictions, pursuant to ARB's Mandatory Reporting Regulation subsection 95111(b)(1).

EF_{unsp} = 0 MT of CO_2e/MWh for points of receipt located in linked jurisdictions.

(f g) *Emission Factors for Specified Sources that are Electricity Generating Facilities or Units, Calculation Methods for Report Years 2008 through 2010*.

The Executive Officer shall calculate emission factors for specified sources of electricity that are generating units or facilities using the following methodology:

$$EF_{sp} = \frac{E_{sp}}{EG}$$

Where:

E_{sp} = CO_2 emissions from electricity generating facility for a specified ~~electric~~ electricity generating facility/unit for the report year ($MTCO_2$)

EG = Net generation from a specified electricity generating facility for the report year (MWh)

(1) For specified electricity generating facilities/units whose operators are subject to reporting or who voluntarily report under the Mandatory Reporting Regulation, E_{sp} shall be equal to the sum of CO_2 emissions from fossil fuel combustion, acid gas scrubbers, or acid gas reagents, as reported to ARB. Similarly, EG shall be the net generation reported to ARB.

(2) For specified electricity generating facilities/units whose operators are not subject to Mandatory Reporting Regulation but who are subject to the Acid Rain Program (40 CFR Part 75), E_{sp} shall be equal to the amount of CO_2 emissions reported to U.S. EPA pursuant to 40 CFR Part 75 for the facility in metric tons for the report year. EG shall be data reported to EIA and published in the EIA 923 Excel file for the reporting year available at http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html (the EIA data).

(3) For specified electricity generating facilities whose operators do not report to ARB under the Mandatory Reporting Regulation and do not report to U.S. EPA under the Acid Rain Program, EG shall be taken from the EIA data for the reporting year. E_{sp} shall be calculated using EIA data as shown below.

$$E_{sp} = 1000 \times \sum(Q_{fuel} \times EF_{fuel})$$

Where:

Q_{fuel} = Heat of combustion for each specified fuel type from the specified ~~electric~~ electricity generating facility for the report year (MMBtu)

EF_{fuel} = CO_2 emission factor for the specified fuel type as taken from the title 17, California Code of Regulations, Chapter 1 Subchapter 9, Article 2, Appendix A ($kgCO_2/MMBtu$).

(h) *Emission Factors for Specified Sources that are Electricity Generating Facilities or Units, Calculation Methods for Report Years 2011 and Subsequent Years.*

Emission factors for Specified Sources that are Electricity Generating Facilities or units shall be facility specific or unit specific emission factors for the specified source published on the ARB Mandatory Reporting website calculated by ARB according to the methods in section 95111(b) of the Mandatory Reporting Regulation.

(~~g~~ i) *Emission Factors for Asset ~~Owning/~~-Controlling Suppliers for Report Years 2008 through 2010.*

The Executive Officer shall calculate emissions factors for ~~asset-owning or~~ asset-controlling suppliers using the following methodology:

Where~~,~~:

$$EF_{asp} = \frac{\sum E_{asp} + \sum(PE_{sp} * EF_{sp}) + (PE_{usp} * EF_{usp}) - \sum(SE_{sp} * EF_{sp})}{\sum EG_{asp} + \sum PE_{sp} + PE_{usp} - \sum SE_{sp}}$$

$\sum E_{asp}$ = the sum of CO_2 emissions from fossil fuel combustion, acid gas scrubbers, or acid gas reagents from each specified electricity generating facility/unit in the asset ~~owning/~~controlling supplier's fleet, as reported to ARB under the Mandatory Reporting Regulation ($MTCO_2$)

$\sum EG_{asp}$ = the sum of net generation for each specified electricity generating facility/unit in the asset ~~owning/~~controlling supplier's fleet for the report year as reported to ARB under the Mandatory Reporting Regulation (MWh)

$\sum PE_{sp}$ = Sum of electricity purchased from specified sources by the ~~asset-owning or~~ asset-controlling supplier for the year as reported to ARB under the Mandatory Reporting Regulation (MWh)

PE_{usp} = Amount of electricity purchased from unspecified sources by the ~~asset-owning or~~ asset-controlling supplier for the year as reported to ARB under the Mandatory Reporting Regulation (MWh)

$\sum SE_{sp}$ = Amount of wholesale electricity sold from a specified source by the ~~asset-owning or~~ asset-controlling supplier for the year as reported to ARB under the Mandatory Reporting Regulation (MWh)

EF_{sp} = CO_2 emission factor as defined for electricity generating units and facilities.

(j) *Emission Factors for Asset-Controlling Suppliers and Multi-jurisdictional Retail Providers for Report Years 2011 and Subsequent Years.*

Emission factors for Asset-Controlling Suppliers and Multi-jurisdictional Retail Providers shall be the supplier-specific emission factors for Asset-Controlling Suppliers and Multi-jurisdictional Retail Providers published on the ARB Mandatory Reporting website calculated by ARB according to the methods in section 95111(b) of the Mandatory Reporting Regulation.

(~~h~~ k) *Fee Liability for Fuels.*

The Executive Officer shall calculate the Fee Liability for each entity reporting pursuant to section 95204(d)(1-3), (d)(5), and (e), based on the quantity of each fuel supplied, consumed or produced, as follows:

$FS_i = (FR_i \times QF_i)$

Where:

FS_i = The Fee for each entity
FR_i = Fuel fee rate for the fuel
QF_i = Quantity of fuel
(Note: The Fee Liability calculation formula for associated gas (Fee Regulation only) is addressed under section 95203(k))

(i l) *Fee Liability for Facilities that Combust Coal, Petroleum Coke (Fee Regulation only), Catalyst Coke (Fee Regulation only), or Refinery Fuel Gas.*

(1) Coal and Petroleum Coke (Fee Regulation only)
The Executive Officer shall calculate the Fee Liability for each entity reporting pursuant to sections 95204(f)(1) and 95204(f)(2), based on the quantity of each fuel consumed as follows:

$FS_i = (FR_i \times QF_i)$

Where:

FS_i = The Fee for each entity

FR_i = Fuel fee rate for the fuel

QF_i = Quantity of fuel

(2) Catalyst Coke (Fee Regulation only) and Refinery Fuel Gas

For entities reporting pursuant to sections 95204(f)(3),and 95204(f)(4), each entity shall be charged a Fee based on the total number of $MTCO_2$ emitted and reported annually. The fee shall be calculated as follows:

$FS_i = CCC \times QE_i$

Where:

FS_i = The Fee for the Entity

CCC = Common Carbon Cost

QE_i = the total amount of emissions associated with the catalyst coke (Fee Regulation only) or refinery fuel gas, as applicable.

(j m) *Fee Liability for ~~Delivered~~ Electricity Delivered in California.*

The Executive Officer shall calculate the fee liability for each entity reporting pursuant to section 95204(g) based on the quantity of electricity delivered, as follows:

$FS_i = \sum(EFR_d \times QM_d) - \sum(EFR_{ge} \times QM_{ge})$

Where:

FS_i = Fee for each entity

QM_d = Quantity of MWh of ~~delivered~~ electricity delivered in California from each specified source, ~~asset-owning or~~ asset-controlling supplier, or unspecified source, as appropriate

EFR_d = Electricity fee rate for electricity from each specified source, ~~asset-owning or~~ asset-controlling supplier, or unspecified source, as appropriate

EFR_{ge} = Electricity fee rate for electricity from qualified exports from each source

QM_{ge} = Quantity of MWh from qualified exports from each source

(k n) *Fee Liability for Entities.*

For entities reporting pursuant to section 95204(d)~~(46)~~(6), and 95204(h), each entity shall be charged a fee based on the total number of $MTCO_2$ emitted and reported annually. The fee shall be calculated as follows:

$FS_i = CCC \times QE_i$

Where:

FS_i = Fee for the Entity

CCC = Common Carbon Cost

QE_i = Total amount of emissions associated with the entity.

NOTE: Authority cited: Sections 38510, 38597, 39600 and 39601, Health and Safety Code. Reference: 38501, 38510, 38597, 39600 and 39601, Health and Safety Code.

§ 95204. Reporting and Recordkeeping Requirements.

(a) *Reporting Format.*

All reports required by this subarticle must be submitted to ARB by using the California Air Resources Board's Greenhouse Gas Reporting Tool, as specified in title 17, California Code of Regulations, section 95104(e), 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 this subarticle. The Reporting Tool is available on ARB's internet website at [www.arb.ca.gov].

(b) *All reporting entities subject to this subarticle must report the following*:

(1) *Report Information*:
- (A) Report year
- (B) Facility information
  1. Official responsible for payment
  2. Facility name
  3. Physical address
  4. Mailing address
  5. Billing address
  6. Description of facility geographic location

(2 C) *Electricity Importer and fuel supplier ~~Entity~~ Information:*
1. ~~(A)~~ Entity name
2. ~~(B)~~ Email address
3. ~~(C)~~ Telephone number
4. Official responsible for payment
5. Mailing address
6. Billing address

(3 2) *Entity Statement of Truth, Accuracy and Completeness.*
Entity signature and date stating: *This report has been prepared in accordance with the AB 32 Cost of Implementation Fee Regulation (subchapter 10, article 3, subarticle 1, sections 95200 to 95207, title 17, California Code of Regulations). The statements and information contained in this emissions data report are true, accurate and complete.*

(c) *Timeline for Reporting.*

(1) Reports from each affected entity for the 2008 calendar year data and the 2009 calendar year must be submitted to ARB by August 16, 2010.

(2) Reports for the 2010 calendar year data ~~and subsequent calendar years~~ must be submitted to ARB by June 30 ~~of the following year, each year~~.

(3) Each electricity importer required to report under this subarticle must submit a report for the 2011 and subsequent reporting years to ARB no later than June 1 of the following year, each year. Each facility owner or operator and fuel supplier required to report under this subarticle must submit a report for the 2011 and subsequent reporting years to ARB no later than April 1 of the following year and each year thereafter.

(d) *Natural Gas Utilities, Users and Pipeline Owners and Operators.*

(1) All public utility gas corporations and publicly owned natural gas utilities operating in California must annually report the aggregate quantity of therms of natural gas delivered at the meter to all end users, and the aggregate quantity of therms of ~~excluding~~ natural gas delivered to electricity generating facilities.

(2) All owners or operators of intrastate pipelines that ~~distribute~~deliver natural gas directly to end users must annually report the aggregate quantity of therms of natural gas directly ~~distributed~~delivered, at the meter to all end users, and the aggregate quantity of therms of ~~excluding~~ natural gas delivered to electricity generating facilities.

(3) All owners or operators that are end users of natural gas received directly from interstate pipelines, except for electricity generating facilities and facilities that combust or consume less than 100,000 therms of natural gas received directly from an interstate pipeline in a reporting year, must annually report the therms of natural gas directly ~~distributed~~delivered, at the meter from the interstate pipeline(s).

(4) All owners or operators of interstate pipelines that ~~distribute~~deliver natural gas directly to end users must annually report the following information for each end user directly receiving ~~natural gas~~100,000 therms of natural gas or more in a reporting year: name, contact address, facility address, and contact phone number.

(5) All California owners or operators that consume natural gas produced on-site and are subject to the verification requirements in Section 95103 of Mandatory Reporting Regulation must report the quantity of therms of natural gas consumed annually of natural gas that is produced on-site, excluding natural gas consumed by an electricity generating facility, in addition to all information required under the Mandatory Reporting Regulation.

(6) All California owners or operators that consume associated gas (Fee Regulation only) produced on-site and that are subject to the verification requirements in Section 95103 of Mandatory Reporting Regulation must report all information required by the Mandatory Reporting Regulation, including the quantities of emissions resulting from the combustion of these fuels, excluding associated gas produced on-site and consumed by on-site electricity generating facilities.

(e) *Producers and Importers of Gasoline and Diesel Fuels.*

All producers and importers of California gasoline, CARBOB or California diesel fuel must report the total amount of each variety of fuel sold or supplied for use in California which they produced or imported. Producers and importers of CARBOB must report the designated volume/volumes of oxygenate associated with each volume of CARBOB ~~and the associated designated volume/volumes of oxygenate~~.

(f) *Coal, Catalyst Coke, Petroleum Coke, or Refinery Gas Combustion or Consumption.*

All entities that are subject to the verification requirements in Section 95103 of the Mandatory Reporting Regulation, except for electricity generating facilities, must report the following information for each of the following substances that are combusted as fuel or consumed as feedstock:

(1) Coal;
The number of tons of coal and the grade of coal combusted or consumed in each calendar year must be reported.

(2) Petroleum coke (Fee Regulation only);
The number of tons of petroleum coke (Fee Regulation only) combusted or consumed in each calendar year must be reported.

(3) Catalyst coke (Fee Regulation only);
The quantity of emissions from combustion as reported each calendar year under the applicable section of the Mandatory Reporting Regulation must be reported.

(4) Refinery fuel gas;
The quantity of emissions from combustion or consumption as reported each calendar year under the applicable section of the Mandatory Reporting Regulation must be reported. If known by

the reporting entity, the quantity of emissions from natural gas or any remaining useful refinery fuel gas generated from the combustion or consumption of natural gas can be excluded. To exclude the quantity of emissions from natural gas, the following method shall be used:

$Q_{rga}=Q_{rg} - (Q_{ng} \times EF_{ng}) - Q_{rgr}$

Where:

Q_{rga} = Adjusted quantity of emissions from refinery gas

Q_{rg} = Quantity of emissions from refinery gas reported through the Mandatory Reporting Regulation

Q_{ng} = Quantity of natural gas

EF_{ng} = Default emission factor for natural gas found in 95203(d)

Q_{rgr} = Quantity of emissions from any remaining useful refinery fuel gas generated from the combustion or consumption of natural gas.

(g) - (i) [No change]

NOTE: Authority cited: Sections 38510, 38597, 39600 and 39601, Health and Safety Code. Reference: 38501, 38510, 38597, 39600 and 39601, Health and Safety Code.

§ 95205. Payment and Collection.

(a) Beginning in fiscal year 2010/2011, and thereafter, within 30 days after the State Budget has been signed by the Governor, the Executive Officer shall provide a written fee determination notice to each affected entity of the amount due. The amount of the fee shall be based on the reports submitted pursuant to section 95204 and the fee calculation formulas set forth in section 95203. ARB will not collect the fee from entities whose total amount due, as calculated per section 95203, is less than or equal to fifty dollars ($50.00).

(b) *Payment Period.* Each entity that is notified by the Executive Officer that it must remit a specified dollar amount to ARB for the current fiscal year shall transmit that dollar amount to ARB for deposit into the Air Pollution Control Fund within 60 days ~~of receipt~~ of the fee determination notice date.

(c) *Late Fees.* The Executive Officer shall assess an additional fee on entities failing to pay the fee within 60 days of receipt of the fee determination notice. The Executive Officer shall set the late fee in an amount sufficient to pay ARB's additional expenses incurred by the entity's untimely payment.

The late fee is in addition to any penalty that may be assessed as provided in section 95206.

(d) *Expenditure of Fees*. The fees collected from the entities are to be expended by ARB only for the purposes of recovering the costs of carrying out the provisions of AB 32 and repaying the Debt.

NOTE: Authority: Sections 38510, 38597, 39600 and 39601, Health and Safety Code.
Reference: Sections 38501, 38505 and 39300, Health and Safety Code.

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Appendix B

Rationale for Proposed Amendments to Definitions – Section 95202

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Rationale for Proposed Amendments to Definitions – Section 95202

Numerous definitions are proposed to be revised, added, or deleted in the Fee Regulation and are listed below. Definitions and sections revised only due to renumbering are not listed.

Most of the definitions are being changed to ensure the Fee Regulation is consistent with the MRR. In many cases, this is due to a specific definition's use in determining applicability or reporting requirements. For several reporting sectors, data used for fee determination for the Fee Regulation is reported pursuant to the MRR. The data are only reported once through a single reporting tool. Primary examples of such reporting sectors are the electricity sector and facilities that combust or consume fuels such as coal or petroleum coke. To allow reporting pursuant to MRR to be used for fee determination under the Fee Regulation, the definitions should be identical. In these cases, the list will simply provide, "revised (added or deleted) for reporting consistency with MRR." In all other cases, a more detailed rationale for the proposed amendment is provided.

While most definitions in the proposed amendments to the Fee Regulation are identical to the corresponding definition in the MRR, some are different, by necessity, due to specific distinctions between the two regulations. In many cases, these proposed amendments to definitions include the phrase "(Fee Regulation only)."

95202(a)(4) "Annual" is revised for reporting consistency with MRR.

95202(a)(6) "Asset-controlling supplier" is revised for reporting consistency with MRR.

95202(a)(7) "Asset-owning supplier" is deleted for consistency with MRR.

95202(a)(8), renumbered to (7), "Associated gas" is amended to "Associated gas (Fee Regulation only)" to differentiate between associated gas in the MRR and associated gas subject to the Fee Regulation. The definition is amended to clarify that Associated Gas is a subset of natural gas. These revisions are necessary to clarify that the term is distinct from the term associated gas in the MRR and reduce reporter confusion as the current definition does not refer to natural gas in the definition.

95202(a)(8) "Aviation gasoline" is added to define those fuels excluded under 95201(b) and maintain consistency with MRR.

95202(a)(9) "Balancing authority" is added for reporting consistency with MRR.

95202(a)(10) "Balancing authority area" is added for reporting consistency with MRR.

95202(a)(12) "Bigeneration Unit" is added for reporting consistency with MRR.

95202(a)(13) "Biodiesel" is revised for reporting consistency with MRR.

95202(a)(15) "Biomass" is added for reporting consistency with MRR.

95202(a)(12), renumbered to (16), "Busbar" is revised for reporting consistency with MRR.

95250(a)(22) "Carbon dioxide equivalent" is revised for reporting consistency with MRR.

95202(a)(20), renumbered to (24), "Catalyst coke" is amended to "Catalyst coke (Fee Regulation only)" to differentiate between catalyst coke in the MRR and catalyst coke subject to the Fee Regulation.

95250(a)(25), renumbered to (29), "Coal" is revised for reporting consistency with MRR.

95250(a)(30) "Cogeneration" is added for reporting consistency with MRR.

95250(a)(26), renumbered to (31), "Cogeneration facility" is revised for reporting consistency with MRR.

95250(a)(27), renumbered to (32), "Cogeneration system" is revised for reporting consistency with MRR.

95202(a)(33) "Cogeneration unit" is added for reporting consistency with MRR.

95202(a)(36) "Consumption" is added to clarify what is to be reported pursuant to section 95204(f).

95202(a)(37) "Consumed on-site" is added to clarify the use of the term specific to reporting requirements.

95250(a)(32), renumbered to (40), "Delivered electricity" is revised for reporting consistency with MRR.

95250(a)(41) "Energy Information Administration," or "EIA" is added for reporting consistency with MRR.

95202(a)(42) "Electricity delivered in California" is added to differentiate between delivered electricity in MRR and delivered electricity subject to the Fee Regulation.

95202(a)(33), renumbered to (43), "Electricity fee rate" is revised to clarify that an emission factor specific to a specified source is used for all electricity from a specified source, while a default emission factor is used for all electricity from an unspecified source.

95202(a)(34), renumbered to (44), "Electricity generating facility" is revised for reporting consistency with MRR.

95202(a)(45) "Electricity generating unit" or "EGU" is added for reporting consistency with MRR.

95202(a)(35), renumbered to (46), "Electricity importers" is revised for reporting consistency with MRR.

95202(a)(36), renumbered to (47), "Emissions" is revised for reporting consistency with MRR, and to clarify that for the purpose of the Fee Regulation an emission source is not directly related to a facility. This is to reflect that upstream fuels emissions are not related to a facility.

95202(a)(37), renumbered to (48), "Emissions data report" or "greenhouse gas emissions data report" or "report" is revised for reporting consistency with MRR, and to clarify for the purpose of the Fee Regulation that the report includes all data required to be reported pursuant to the MRR and the Fee Regulation.

95202(a)(39), renumbered to (50), "End user" is revised for reporting consistency with MRR.

95202(a)(42), renumbered to (53), "Executive Officer" is revised for consistency with MRR.

95202(a)(43), renumbered to (54), "Facility" is revised for reporting consistency with MRR.

95202(a)(46), renumbered to (57), "First deliverer of electricity" is revised to clarify the use of the term specific to section 95201(a)(4).

95202(a)(48), renumbered to (59), "Fossil fuel" is revised for reporting consistency with MRR.

95202(a)(49), renumbered to (60), "Fuel" is revised for reporting consistency with MRR.

95202(a)(62) "Fuel supplier" is added for reporting consistency with MRR.

95202(a)(64) "Generated Electricity" is added for reporting consistency with MRR.

95202(a)(53), renumbered to (66), "Global warming potential" or "GWP" is revised for reporting consistency with MRR.

95202(a)(69) "Grid" or "Electric power grid" is added for reporting consistency with MRR.

95202(a)(70) "Grid-dedicated facility" is added for reporting consistency with MRR.

95202(a)(71) "Gross generation" or "gross power generated" is added for reporting consistency with MRR.

95202(a)(56), renumbered to (72), "Imported electricity" is revised for reporting consistency with MRR.

95202(a)(57), renumbered to (73), "Interstate pipeline" is revised for reporting consistency with MRR.

95202(a)(58), renumbered to (74), "Intrastate pipeline" is revised for reporting consistency with MRR.

95202(a)(59), renumbered to (75), "Kerosene" is revised for reporting consistency with MRR.

95202(a)(76), "Kerosene type jet fuel" is added to define those fuels excluded under 95201(b) and to maintain consistency with MRR.

95202(a)(77) "Linked jurisdiction" is added for reporting consistency with MRR.

95202(a)(60), renumbered to (78), "Liquefied petroleum gas" or "LPG" is revised for reporting consistency with MRR.

95202(a)(79) "Local distribution company" or "LDC," is added to differentiate between an intrastate pipeline and a distribution pipeline for natural gas.

95202(a)(62), renumbered to (81), "Marketer" is revised for reporting consistency with MRR.

95202(a)(65), renumbered to (84), "Metric ton" or "MT" is revised for reporting consistency with MRR.

95202(a)(85) "MMBtu" is added for reporting consistency with MRR.

95202(a)(87) "Multi-jurisdictional retail provider" is added for reporting consistency with MRR.

95202(a)(88) "Municipal solid waste" is added for reporting consistency with MRR.

95202(a)(67), renumbered to (89), "Nameplate generating capacity" is revised for reporting consistency with MRR.

95202(a)(68), renumbered to (90), "Natural gas" is revised for reporting consistency with MRR.

95202(a)(92) "NERC E-tag" is added for reporting consistency with MRR.

95202(a)(70), renumbered to (93), "Net generation" or "Net power generated" is revised for reporting consistency with MRR.

95202(a)(71), renumbered to (94), "Operational control" is revised for reporting consistency with MRR.

95202(a)(72), renumbered to (95), "Operator" is revised for reporting consistency with MRR.

95202(a)(97) "Oxygenate" is added to clarify the term as used in section 95204(e).

95202(a)(74), renumbered to (98), "Payment period" is revised to reflect the amendment to section 95205(b).

95202(a)(75), renumbered to (99), "Petroleum coke" is amended to "Petroleum coke (Fee Regulation only)" to differentiate between petroleum coke in the MRR and petroleum coke subject to the Fee Regulation.

95202(a)(76), renumbered to (100), "Petroleum refinery" is revised for reporting consistency with MRR.

95202(a)(77), renumbered to (101), "Point of delivery" is revised for reporting consistency with MRR.

95202(a)(80), renumbered to (104), "Process emissions" is revised for reporting consistency with MRR.

95202(a)(105) "Produced on-site" is added to clarify the term as used in section 95204(d).

95202(a)(81) "Producer" is deleted as the term is not used in the Fee Regulation in any context other than as defined in subsections 95202(a)(14), 95202(a)(15), or 95202(a)(16) in the current Fee Regulation.

95202(a)(82) "Production facility" is deleted as the term is not used in the Fee Regulation other than in the proposed deleted subsection 95202(a)(81).

95202(a)(83), renumbered to (106), "Propane" is revised for reporting consistency with MRR.

95202(a)(86), renumbered to (109), "Purchasing-selling entity" is revised for reporting consistency with MRR.

95202(a)(110) "Qualified Export" is added for reporting consistency with MRR.

95202(a)(111) "Radiative forcing" is added to clarify the use of the term in the existing definition for "Global warming potential" in the existing Fee Regulation.

95202(a)(87), renumbered to (112), "Refinery gas" is amended to "Refinery fuel gas" for reporting consistency with MRR.

95202(a)(88), renumbered to (113), "Renewable diesel" is revised for reporting consistency with MRR.

95202(a)(114) "Renewable energy" is added for reporting consistency with MRR.

95202(a)(115) "Replacement electricity" is added for reporting consistency with MRR.

95202(a)(116) "Reporting entity" is added for reporting consistency with MRR.

95202(a)(89), renumbered to (117), "Report Year" or "Reporting Year" is revised for reporting consistency with MRR.

95202(a)(91), renumbered to (119), "Retail provider" is revised for reporting consistency with MRR.

95202(a)(121) "Short ton" or "Ton" is added for reporting consistency with MRR.

95202(a)(93), renumbered to (122), "Source" is revised for reporting consistency with MRR.

95202(a)(94), renumbered to (123), "Specified source of power" is amended to "Specified source of electricity" for reporting consistency with MRR.

95202(a)(124) "Stand-alone generating facility" is added for reporting consistency with MRR.

95202(a)(127) "Substitute power" or "substitute electricity" is added for reporting consistency with MRR.

95202(a)(129) "Thermal energy" is added for reporting consistency with MRR.

95202(a)(98) "Ton" is deleted as the terms ton and short ton are combined for clarity in added subsection 95202(a)(119).

95202(a)(98), renumbered to (130), "Unspecified source of power" is amended to "Unspecified source of electricity" for reporting consistency with MRR.

95202(a)(131) "Useful thermal output" is added for reporting consistency with MRR.

95202(a)(132) "Variable renewable resource" is added for reporting consistency with MRR.

95202(a)(133) "Wholesale sales" is added to clarify the applicability of fees specific to MWhs delivered by a multi-jurisdictional retail provider.

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Appendix C

Public Workshop Notice

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Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Linda S. Adams
Acting Secretary for Environmental Protection

Edmund G. Brown Jr.
Governor

Amendments to the AB 32 Cost of Implementation Fee Regulation

The Air Resources Board (ARB) invites you to participate in a public workshop to discuss proposed amendments to the AB 32 Cost of Implementation Fee Regulation (COI Regulation).

The COI Regulation provides a schedule of fees to be paid by sources of greenhouse gas emissions to support the administration costs of implementing AB 32, the California Global Warming Solutions Act of 2006, and was adopted by ARB pursuant to Health and Safety Code Section 38597. Under AB 32, ARB has developed numerous measures supported by the regulation to reduce greenhouse gas emissions and help clean the air, protect the environment and drive innovative new solutions to clean energy.

When and Where is the Meeting?
The workshop will be held at the following location:

DATE:	Friday, January 21, 2011
TIME:	1:30 p.m.
PLACE:	Cal/EPA Headquarters Building Sierra Hearing Room, 2nd Floor 1001 I Street Sacramento, CA 95814

Meeting Topic Details
The purpose of this workshop is to discuss with stakeholders ARB's proposed amendments to the COI Regulation that are necessary to be consistent with recent amendments to ARB's Regulation for Mandatory Reporting of Greenhouse Gas Emissions. Staff will make the proposed amendments to the COI Regulation available prior to the workshop and plans to take the amendments to the Board for consideration at its April 28, 2011 public meeting. The workshop will also provide an opportunity for comments from stakeholders and the public.

Meeting Materials
The materials for this workshop will be posted prior to the workshop at ARB's website http://www.arb.ca.gov/cc/adminfee/meetings/meetings.htm.
At this website, you may also join our electronic mailing list to receive further notices of ARB activities and public meetings related to the implementation of AB 32.

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: http://www.arb.ca.gov.

Can't Make it to the Meeting?
This meeting will be webcast, and viewers can E-mail written comments or questions during the session to ccworkshops@arb.ca.gov. Webcast links are posted at http://www.calepa.ca.gov/broadcast/?BDO=1. ARB recommends that you do not run other programs while viewing the webcast, as it may interrupt or lower the quality of the signal.

Directions to Cal/EPA
There are many ways to arrive at the Cal/EPA Headquarters Building but we encourage you to take public transportation or drive low emission/high efficiency vehicles whenever possible. Use the following link for directions and information on public transit: http://www.calepa.ca.gov/EPAbldg/location.htm.

Special Accommodations or Language Assistance
If you require special accommodations or language needs, please contact Mary Farr at (916) 445-8290 or mfarr@arb.ca.gov as soon as possible, but no later than 7 business days before the scheduled event/meeting. TTY/TDD/Speech to Speech users may dial 7-1-1 for the California Relay Service.

We Value Your Input
We welcome and encourage your participation in this important effort. If you have questions regarding the workshop or the COI Regulation, please contact Bill Blackburn at (916) 322-7154 or bblackbu@arb.ca.gov.

Sincerely,

Kevin M. Kennedy
Assistant Executive Officer
Office of Climate Change