STATE OF CALIFORNIA

California Environmental Protection Agency

**AIR RESOURCES BOARD**

# ATTACHMENTS C TO F

## SUPPLEMENTAL MATERIALS DOCUMENT FOR

## STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

# MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

## PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)

Planning and Technical Support Division
Emission Inventory Branch

October 19, 2007

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STATE OF CALIFORNIA

California Environmental Protection Agency

# AIR RESOURCES BOARD

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**STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING**

**MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)**

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# ATTACHMENT C

# Explanation of Interim Emissions Attribution Methods for the Electricity Sector

October 19, 2007
California Air Resources Board

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## INTERIM EMISSIONS ATTRIBUTION METHODS
## FOR THE ELECTRICITY SECTOR

### 1. Introduction

The regulation for the mandatory reporting of greenhouse gas emissions was crafted by the staff of the California Air Resources Board (ARB) with the intention of gathering all information necessary to continue ARB's effort to effectively implement the requirements of the Global Warming Solutions Act of 2006. Specifically, the information collected through this mandatory reporting program will contribute to:

- Improvement to the statewide greenhouse gas (GHG) emission inventory.
- Development of a scoping plan to assess how best to reduce emissions.
- Support for future regulatory strategies.

Operators of electric generating facilities, retail providers, and marketers will submit their GHG emissions data reports to ARB electronically and the data will be stored in an ARB database. These reports will consist of both source-based emissions data and electricity transactions data. Emissions associated with electricity transactions will be calculated in subroutines inside the ARB database. This document explains how the ARB database will to assign emissions to electricity transactions and possible ways to calculate emission responsibilities for operators regulated in potential future regulations.

### 2. Relationship to Regulatory Strategies

At this time the details of future regulatory strategies for the electricity sector, such as market-based mechanisms, remain uncertain. Therefore, the mandatory reporting requirements for the electricity sector were designed to gather all information needed to support several possible approaches. The mandatory reporting regulation itself does not specify how emission responsibilities will be assigned in any future regulatory system.

Three general types of market approaches are currently under consideration for the electricity sector. These approaches are commonly referred to by names which indicate the point of regulation within the sector—"source-based", "deliverer/first-seller", or "load-based". Under a source based cap, regulators assign responsibility for emissions to the direct sources of these emissions. In the electricity sector the primary sources of emissions are the electrical generating facilities. The deliverer/first-seller approach is a modification of the source-based approach which accounts for emissions associated with electricity imports by placing responsibility for these imported emissions on the entity which initially sells the power into California. Under a load-based system, the retail providers are held responsible for all emissions generated to produce the electricity used to serve their customers' load.

The most natural use of the attribution method described in this document would be to assign emission responsibility to retail providers for use in a load-based scheme; however, the portions of this method which treat power brought into California (imports) could also indicate how responsibilities might be assigned to retail providers' and marketers' under a deliverer/first-seller approach. This document should be read with the understanding that the emission attribution formulas will likely need to be revised as the design of future regulations take shape.

## 3. General Description of the Mandatory Reporting Database

Under the mandatory reporting program, ARB will assign each facility a unique identification number (ARB ID). Operators will quantify and report emissions associated with the electric generating facilities they operate. The operators will also specify the total net generation of each of the facilities they operate. The ARB database will calculate an emission factor (metric tonnes of emissions per megawatt hour) for each generating facility based on this data.

### 3.1. Electricity Transactions Involving Specified Sources

Operators will report electricity transactions (e.g., purchases and sales) in megawatt hours (MWh); the ARB database will assign emissions values to these electricity transactions within the ARB database subroutines using the ARB facility ID number to match the transaction to the appropriate emission factor.

For electricity transactions from specified generating facilities whose operator does not report to ARB, the ARB will designate an ARB ID to the generating facility and assign emissions and net generation based on U.S. Environmental Protection Agency (U.S. EPA) data submitted under 40 CFR Part 75 or Energy Information Administration (EIA) data in coordination with the California Energy Commission.

### 3.2. Electricity Transaction Involving Unspecified Sources

Operators will report purchases and sales from unspecified sources and, for each transaction, specify a market or region affiliated with that transaction. The possible categories are: Pacific Northwest (PNW), Southwest (SW), California Independent System Operator (CAISO) pooled real-time market (CAISO RTM), CAISO pooled integrated forward market (CAISO IFM), California (CA), or unknown (Unk). The database will match the purchase or sale with the corresponding default emission factor assigned to each region or market. The default emission factors are discussed in detail later in this document.

Some asset owning or asset controlling suppliers may choose to request an ARB ID that represents their fleet of generating facilities and submit a GHG emissions data report. Retail providers will be able to use the supplier's ID to designate purchases from the supplier's fleet. The ARB database will match purchases from these suppliers with the average emission rate for the supplier's fleet rather than an unspecified default emission factor.

The database will also compute emission factors assigned to retail sales emission factors for unspecified wholesale sales for each retail provider. These formulas are discussed in detail later in this document.

## 4. Emissions Attribution Equations

ARB has not determined if it will implement a trading program, or a regulatory design for the electric power sector. If ARB participates in a regional or national source-based approach to regulation, the operators of generating facilities would likely be the point of regulation and they would be responsible for emissions from their facilities. If a future regulation is based on a load-based or deliverer/first-seller approach, the computation for emissions responsibilities is more complex.

The equation below shows how emissions could be assigned by the ARB database to all types of electricity transactions data. The current structure of the equation is configured to calculate total emissions attributed to a retail provider. This form would be most useful under a load-based point of regulation. However, the components of this equation could also be adapted to calculate emission responsibilities for importers and in-state generators under a deliverer/first-seller approach. Each term in the equation is examined in greater detail in the following sections. How each of these components will be treated in a future trading scheme or how emission responsibilities are assigned under any approach will be decided as future regulations are designed and adopted.

For now, the ARB database will attribute emissions to each retail provider as indicated. The terms that constitute this equation are defined in greater detail in the following sections.[1] $CO_2$ emissions from the combustion of biomass-derived fuels are excluded. Purchases from hydroelectric generating facilities greater than 30 MW or from nuclear facilities that do not have contracts in effect prior to January 1, 2008, that remain in effect or have been renewed without interruption, are assigned emissions based on default emission factors (see below for a more detailed description). Power purchases from out-of-state sources exclude wheel-through transactions.

[1] Throughout this document, a variable with a subscripted "E" will indicate an emissions variable; a subscript of "MWh" will indicate a power transaction variable.

ARB will attribute separate indirect $CO_2$, $N_2O$, and $CH_4$ emissions numbers for each retail provider as follows:

$$Emiss_{RP} = PP_{E,\ specified} + PP_{E,\ unspecified} + AOSD_E - CaWS_{E,\ specified} - CaWS_{E,\ unspecified}$$

Where:

$Emiss_{RP}$ = emissions attributed to a given retail provider, metric tonnes

$PP_{E,\ specified}$ = sum of emissions from power purchased or taken from specified sources, metric tonnes

$PP_{E,\ unspecified}$ = sum of emissions from power purchased or taken from unspecified sources, metric tonnes

$AOSD_E$ = sum of emissions associated with the adjusted ownership share differential (AOSD) as applicable by facility, metric tonnes

$CaWS_{E,\ specified}$ = sum of emissions from wholesale sales to counterparties inside California of power purchased from specified sources, metric tonnes

$CaWS_{E,\ unspecified}$ = sum of emissions from wholesale sales to counterparties inside California from unspecified sources, metric tonnes

### 4.1. Power Taken or Purchased from Specified Sources ($PP_{E,\ specified}$)

Retail providers are required to report the total amount of power taken from specified facilities operated by the retail provider ($GF_{MWh}$) and purchased or taken from other specified sources ($PP_{MWh,\ specified,\ NO}$), disaggregated by the plant of origin (as indicated by an ARB identification number for each plant). The ARB database will then multiply power taken or purchased from specified sources by the appropriate emission factor based on data reported for the corresponding generating facility, and sum these values to calculate the total emissions associated with these specified purchases ($PP_{E,\ specified}$). If the generating facility does not report directly to ARB, the emissions ARB assigns will be based on finalized reports under 40 CFR Part 75 or plant-level fuel consumption data from the Energy Information Administration. The following equations clarify the above statements:

$$PP_{E,specified} = GF_E + PP_{E,specified,NO}$$

$$PP_{MWh,specified} = GF_{MWh} + PP_{MWh,specified,NO}$$

Where:

$PP_{E,\ specified}$ = total emissions associated with power purchased or taken from specified sources (both those operated by the retail provider and not operated by the retail provider), metric tonnes

$GF_E$ = sum of emissions from power taken from all generating facilities operated by the retail provider, metric tonnes

$PP_{E,\ specified,\ NO}$ = sum of emissions from power purchased or taken from specified sources not operated by the retail provider, metric tonnes

$PP_{MWh,\ specified}$ = total power purchased or taken from specified sources, MWh

$GF_{MWh}$ = sum of power taken from generating facilities operated by the retail provider, MWh
$PP_{MWh,\ specified,\ NO}$ = sum of power purchased or taken from all specified sources not operated by the retail provider, MWh

$$GF_E = \sum_{i=1}^{n} GF_{MWh,i} EF_i$$

$$GF_{MWh} = \sum_{i=1}^{n} GF_{MWh,i}$$

Where:
$GF_{MWh,\ i}$ = net generation taken from plant i, MWh
$EF_i$ = ARB assigned emission factor for plant i, metric tonnes per MWh
n = total number of facilities operated by the retail provider

$$PP_{E,specified,NO} = \sum_{i=1}^{n} PP_{MWh,i} EF_i$$

$$PP_{MWh,specified,NO} = \sum_{i=1}^{n} PP_{MWh,i}$$

Where:
$PP_{MWh,\ i}$ = net generation purchased or taken from plant i, MWh
$EF_i$ = ARB assigned emission factor for plant i, metric tonnes per MWh
n = total number of specified facilities the retail provider purchased or took power from

#### *4.1.1. Special Case: Emissions Calculations for Power Purchased from Large Hydroelectric and Nuclear Generating Facilities*

The California Public Utilities Commission (CPUC) and the California Energy Commissions (CEC) recommend that an emissions value be assigned to power purchased from nuclear or large hydroelectric plants (>30 megawatts) unless the retail provider purchased the power through a power contract that was in effect prior to January 1, 2008 and is either still in effect or has been renewed without interruption. This stipulation is based on the belief that nuclear and large hydro facilities are unlikely to change their operating parameters due to new contracts; therefore, new contracts associated with existing facilities of these types would not result in overall emissions reductions. ARB will calculate emissions associated with nuclear and large hydro purchases that do not meet the stipulation by assigning the default emission factors for purchases of unspecified power from that region to these purchases as recommended (see below).

### 4.2. Power Purchased from Unspecified Sources ($PP_{E, unspecified}$)

#### *4.2.1. Default Emission factor for Power Purchased from Unspecified Sources*

One of the challenges of defining emissions for the power sector has been dealing with power purchased or sold from unknown or "unspecified" sources. The California Public Utilities Commission (CPUC) and the California Energy Commissions (CEC) have jointly worked on this issue and recommended that the ARB use a single default emission factor of 1,100 pounds of $CO_2$ per MWh for purchases from all regions and markets.

Eventually, it is possible that each of the regions and the pooled CAISO markets will be assigned unique default emission factor values that could be updated periodically. In the meantime, ARB will use the recommended default emission value to calculate emissions associated with purchases from these regions and markets. At the recommendation of CPUC and CEC staff, the emission factors will be increased by 7.5 percent for PNW, SW, and unknown regions in order to reflect the amount of power associated with transmission line losses. The line losses are already included in the emission factor for in-state transactions.

ARB also must establish default emission factors for $N_2O$ and $CH_4$ for unspecified sources. These factors were not provided by the CPUC and the CEC. ARB staff developed these additional default emission factors using the CEC method[2] and IPCC 2006 emission factors[3] for estimating emissions from imported electricity. In order to smooth out any potential spikes, a 3-year average will be used, using data for years 2003-2005 from the Energy Information Administration (EIA)[4]. The 3-year average emission factor for $CO_2$ from the Pacific Northwest (PNW) and Pacific Southwest (PSW) for coal and natural gas were determined, and then averaged to obtain a single $CO_2$ emission factor for unspecified imports of coal and natural gas, along with the $CH_4$ and $N_2O$ factors that go along with each.

**Table B-1**: Fuel Specific Emission Factors for Unspecified Imports (2003-2005 Avg.)

| **Fuel** | ***lbCO2/MWh*** | ***lbCH4/MWh*** | ***lbN2O/MWh*** |
|---|---|---|---|
| Average Coal | 2,283.86 | 0.0237 | 0.0356 |
| Average Natural Gas | 1,079.10 | 0.0204 | 0.0020 |

[2] The CEC methodology is explained in the CEC Staff Final Report, Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004, December 2006 (CEC-600-2006-013-SF) http://www.energy.ca.gov/2006publications/CEC-600-2006-013/CEC-600-2006-013-SF.PDF.

[3] IPCC (2006a) *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, prepared by the National Greenhouse Gas Inventories Programme, Egglestion, H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds). Published: IGES, Japan, IPCC 2006 www.ipcc-nggip.iges.or.jp/public/2006gl/index.htm (accessed 8/26/07)

[4] EIA (2007) Combined (Utility, Non-Utility, and Combined Heat & Power Plant) Database, http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html (accessed 10/17/2007)

The CEC method for determining unspecified imports was used to estimate the fraction of such imports that are not fuel based (hydro, nuclear, etc). These values were based on the same 3-year average method and a single fraction was determined. This value was 39.3 percent.

Next, the values from Table 1 for $CO_2$ from coal and natural gas were used algebraically with the assumed 39.3 percent non-carbon import value to determine what percent of each type would be needed to make a composite emission factor of 1,100 lbs $CO_2$ per MWh as recommended by the CPUC and CEC. The percentages come out to be: 36.9 percent from coal, 23.8 percent from natural gas and 39.3 percent from non-carbon sources. Using these percentages, the same percentage was taken of each fuel type's $CH_4$ and $N_2O$ emission factors and added together to obtain an estimate of the $CH_4$ and $N_2O$ emission factors for unspecified imports that corresponds to the CPUC/CEC $CO_2$ default emission factor. The final result is shown in Table B-2.

**Table B-2**: Emission Factors for Unspecified Imports

| **Category** | ***lbCO2/MWh*** | ***lbCH4/MWh*** | ***lbN2O/MWh*** |
|---|---|---|---|
| Unspecified Electricity Imports | 1,100.00 | 0.0136 | 0.0136 |

The final default emission factors for all regions and markets that also reflect line losses are summarized in Table B-3.

**Table B-3:** Default Emission Factors for Unspecified Transactions

| **Region** | ***lbCO2/MWh*** | ***lbCH4/MWh*** | ***lbN2O/MWh*** |
|---|---|---|---|
| California | 1,100.00 | 0.0136 | 0.0136 |
| CAISO pooled real-time market | 1,100.00 | 0.0136 | 0.0136 |
| CAISO pooled forward integrated market | 1,100.00 | 0.0136 | 0.0136 |
| PNW | 1,182.50 | 0.0146 | 0.0146 |
| SW | 1,182.50 | 0.0146 | 0.0146 |
| Unknown | 1,182.50 | 0.0146 | 0.0146 |

The ARB database will convert pounds of emissions to metric units for the purpose of calculating greenhouse gas emissions associated with electricity transactions.

#### *4.2.2. Calculations using the Default Emission Factors for Unspecified Purchases*

Retail providers will report purchases from unspecified sources and indicate the region or market of origin for each transaction as described above. The database will match the purchase with the corresponding default emission factor assigned to each region or market. The following equations clarify these calculations:

$$PP_{E,unspecified} = PP_{E,unsp,PNW} + PP_{E,unsp,SW} + PP_{E,unsp,CA} + PP_{E,unsp,ISORTM} + PP_{E,unsp,ISOIFM} + PP_{E,unsp,unk}$$

$$PP_{E,unsp,r} = EF_r\left(\sum_{i=1}^{n} PP_{MWh,unsp,r,i}\right)$$

Where:

$PP_{E,\ unspecified}$ = sum of emissions based on power purchased from all unspecified sources, metric tonnes

$PP_{E,\ unsp,\ r}$ = sum of emissions from unspecified power purchased from one region or pooled market, metric tonnes

$EF_r$ = default emission factor for region r, metric tonnes per MWh

$PP_{MWh,\ unsp,\ r,\ i}$ = individual unspecified power purchase i from region r

r = region or pooled market, Pacific Northwest (PNW), southwest (SW), California (CA), CAISO pooled real-time market (ISORTM), CAISO pooled integrated forward market (ISOIFM), or unknown (Unk)

n = total number of purchases from region r

#### *4.2.3. Special Case: Supplier-based Emission Factors*

As mentioned previously, some asset owning or asset controlling suppliers may optionally request an ARB identification number that represents their fleet of generating facilities. Retail providers will then have the ability to designate unspecified purchases as originating from a specified supplier rather than from a region or pooled market. The ARB database will match purchases from a supplier with the emission rate for the supplier's fleet for that report year rather than apply a default emission factor.

### 4.3. Adjusted Ownership Share Differential ($AOSD_E$)

The CPUC and the CEC noted that high-emitting facilities owned or partially owned by California retail providers could potentially modify their power contracts so that emissions (as calculated by ARB) appear to be reduced when, in fact, overall emissions remain unchanged. To address this issue an "adjusted ownership share differential" is calculated.

If a retail provider has an ownership share in a facility that emits more than 1,100 lbs of $CO_2$ per MWh the retail provider must calculate the ownership share differential for that facility as follows:

$$OSD_{MWh,i} = 0.9(OS_i)(NG_{MWh,i}) - GF_{MWh,i}$$

Where:

$OSD_{MWh,\ i}$ = power ownership share differential for facility i, MWh

$OS_i$ = ownership share of facility i, percentage expressed as a value from 0-1 (e.g., 50% = 0.5)

$NG_{MWh,i}$ = total net generation of facility i, MWh
$GF_{MWh,i}$ = net generation taken from plant i, MWh

For retail providers with a positive ownership share differential for an owned or partially-owned facility, the retail provider will first adjust the ownership share differential for certain acceptable types of wholesale sales and then report the adjusted ownership share differential. The ARB database will use the adjusted ownership share differential to calculate an emissions attribution using the retail provider's emission factor for wholesale sales from unspecified sources.[5] The following equations clarify how this is accomplished:

$$AOSD_{MWh,i} = OSD_{MWh,i} - NonCaWS_{MWh,OK,i}$$

Where:

$AOSD_{MWh,i}$ = adjusted ownership share differential for facility i, MWh
$OSD_{MWh,i}$ = ownership share differential for facility i, MWh
$NonCaWS_{MWh,OK,i}$ = certain wholesale sales made by the retail provider (or on behalf of the retail provider) from facility i located to counterparties located outside of California[6], MWh

$$AOSD_E = \sum_{i=1}^{n}(AOSD_{MWh,i})(EF_{UWS})$$

Where:

$AOSD_E$ = sum of emissions associated with the adjusted ownership share differential (AOSD) as applicable by facility, metric tonnes
$AOSD_{MWh,i}$ = adjusted ownership share differential for facility i, MWh
$EF_{UWS}$ = emission factor assigned to unspecified wholesale sales, metric tonne per MWh
n = number of facilities with a positive ownership share differential ($OSD_{MWh,i}$>0)

### 4.4. Wholesale Sales to Counterparties within California Involving Power Purchased or Taken from Specified Sources ($CaWS_{E,\ specified}$)

Retail providers' overall emissions attributions will be reduced by the emissions value associated with wholesale sales of power to other Californian entities. Retail providers are required to indicate the destination of all specified sales in order to ensure this accounting can take place.

For sales from specified sources, the ARB database will multiply the power sold by the appropriate emission factor based on data reported for the corresponding generating facility to calculate the emissions associated with wholesale sales to California counterparties from each specified source. If the specified generating facility does not report directly to ARB, the emissions ARB assigns will be based on

[5] The derivation of this factor is described in Section 4.5.1.
[6] See section 95111of the regulation for more details as to what types of sales qualify

finalized reports under 40 CFR Part 75 or plant-level fuel consumption data from the Energy Information Administration. The following equations clarify the above statements:

$$CaWS_{E,specified} = CaWS_{E,GF} + CaWS_{E,specified,NO}$$

$$CaWS_{MWh,specified} = CaWS_{MWh,GF} + CaWS_{MWh,specified,NO}$$

Where:

$CaWS_{E,\ specified}$ = total amount of emissions associated with wholesale sales to counterparties inside of California involving power purchased or taken from specified sources, metric tonnes

$CaWS_{E,\ GF}$ = sum of emissions from wholesale sales to counterparties inside of California from sources operated by the retail provider, metric tonnes

$CaWS_{E,\ specified,\ NO}$ = sum of emissions from wholesale sales to counterparties inside of California of power purchased or taken from specified sources not operated by the retail provider, metric tonnes

$CaWS_{MWh,\ specified}$ = total amount of wholesale sales to counterparties inside of California involving power purchased or taken from specified sources, MWh

$CaWS_{MWh,\ GF}$ = sum of power sold from all sources operated by the retail provider to counterparties inside of California, MWh

$CaWS_{MWh,\ specified,\ NO}$ = sum of all wholesale sales to counterparties inside of California of power initially purchased or taken from sources not operated by the retail provider, MWh

$$CaWS_{E,GF} = \sum_{i=1}^{n} CaWS_{MWh,i} EF_i$$

$$CaWS_{MWh,GF} = \sum_{i=1}^{n} CaWS_{MWh,i}$$

Where:

$CaWS_{MWh,\ i}$ = net generation sold in California taken from operated plant i, MWh

$EF_i$ = ARB assigned emission factor for plant i, metric tonnes per MWh

n = total number of facilities operated by the retail provider

$$CaWS_{E,specified,NO} = \sum_{i=1}^{n} CaWS_{MWh,i} EF_i$$

$$CaWS_{MWh,specified,NO} = \sum_{i=1}^{n} CaWS_{MWh,i}$$

Where:

$CaWS_{MWh,\ i}$ = net generation sold inside of California purchased or taken from plant i, MWh

$EF_i$ = ARB assigned emission factor for plant i, metric tonnes per MWh

n = total number of facilities the retail provider purchased or took power from (but did not operate)

## 4.5. Unspecified Wholesale Sales to Counterparties within California ($CaWS_{E,\ unspecified}$)

### *4.5.1. Emission Factors for Unspecified Wholesale Sales*

The ARB database will calculate an emission factor for unspecified wholesale sales for each retail provider. The emission factors are calculated as follows:

$$EF_{UWS} = \frac{PP_E - CaWS_{E,specified} - ExpWS_{E,specified} - NL_E}{PP_{MWh} - CaWS_{MWh,specified} - ExpWS_{MWh,specified} - NL_{MWh}}$$

Where:

$EF_{UWS}$ = retail provider's emission factor for unspecified wholesale sales, metric tonnes per MWh

$PP_E$ = sum of emissions from power purchased or taken from specified and unspecified sources (including power plants operated by the retail provider), metric tonnes

$(PP_E = PP_{E,\ specified} + PP_{E,\ unspecified})$

$CaWS_{E,\ specified}$ = sum of emissions associated with wholesale sales to counterparties inside of California originating from specified sources, metric tonnes

$ExpWS_{E,\ specified}$ = sum of emissions associated with wholesale sales from specified sources exported to regions outside California, metric tonnes

$NL_E$ = sum of emissions based on power claimed to serve native load (taken from generating facilities operated by the retail provider and power purchased or taken from other specified sources), metric tonnes

$PP_{MWh}$ = sum of power purchased or taken from specified and unspecified sources (including plants operated by the retail provider), MWh

$(PP_{MWh} = PP_{MWh,\ specified} + PP_{MWh,\ unspecified})$

$CaWS_{MWh,\ specified}$ = sum of power sold wholesale from specified sources to counterparties inside California, MWh

$ExpWS_{MWh,\ specified}$ = sum of power sold wholesale from specified sources exported to regions outside California, MWh

$NL_{MWh}$ = sum of power claimed to serve native load (taken from generating facilities operated by the retail provider and purchased or taken from other specified sources), MWh

### *4.5.2. Calculation of Unspecified Wholesales Sales to Counterparties within California*

Once the unspecified wholesale sales emission factor has been established the emissions attributable to unspecified wholesale sales to parties within California can be calculated as follows:

$$CaWS_{E,unspecified} = EF_{UWS} CaWS_{MWh,unspecified}$$

$$CaWS_{MWh,unspecified} = \sum_{i=1}^{m} CaWS_{MWh,unspecified,i}$$

Where:

$CaWS_{E,\ unspecified}$ = sum of emissions from wholesale sales from unspecified sources to counterparties inside California, metric tonnes

$CaWS_{MWh,\ unspecified,\ i}$ = individual unspecified wholesale sale to a counterparty i within California, MWh

$EF_{UWS}$ = emission factor for unspecified wholesale sales, metric tonnes per MWh

$CaWS_{MWh,\ unspecified,\ i}$ = sum of all unspecified wholesale sales to counterparties within California, MWh

m = total number of unspecified sales to counterparties inside of California

## 5. Emission Factors for Retail Sales

The ARB database will calculate emission factors for each retail provider that represent emissions per MWh associated with retail sales. In the event that ARB should choose to calculate emissions associated with indirect power usage for entities outside of the electric sector, the appropriate emission factors by retail provider would be multiplied by the amount of power used by the end user. The emission factor for retail sales will be calculated as follows:

$$EF_{RS} = (PP_E - WS_E) / (PP_{MWh} - WS_{MWh})$$

Where

$EF_{RS}$ = emission factor for retail sales, metric tonnes per MWh

$PP_E$ = sum of emissions from power purchased or taken from specified and unspecified sources, metric tonnes

$$(PP_E = PP_{E,\ specified} + PP_{E,\ unspecified})$$

$WS_E$ = sum of emissions from all specified and unspecified wholesale sales including power exports, metric tonnes

$PP_{MWh}$ = sum of total power purchased or taken from facilities from specified and unspecified sources, MWh

$WS_{MWh}$ = sum of all specified and unspecified wholesale sales including power exports, MWh

### *5.1. Special Case: Emission Factors for Retail Sales from Retail Providers with "Green Programs"*

Some retail providers offer environmentally differentiated retail electricity products. For these products, retail providers purchase renewable energy and renewable energy credits specifically for the use of green energy customers who pay a premium for this power. Retail providers may choose to report green power retail sales separately from other retail power sales.

When the retail sales from these green products are reported, ARB will attribute a specified emission factor to these sales and remove these sales from the retail provider's general retail sales emission factor ($EF_{RS}$).

## 6. Wheel-through Transactions

Wheel-through transactions, where power is imported into California but terminates outside of California, are reported separately and are not included in any of the above calculations.

## 7. ARB Emissions Inventory for the Power Sector

ARB will calculate the statewide emissions inventory related to the power sector by summing the emissions from generating facilities located inside California as reported by the operators of the generating facilities and the emissions from power imported into California from specified and unspecified sources (including out-of-state generating facilities operated by California operators) as reported by retail providers and marketers. In the absence of a regional source-based regulation, the ARB inventory may also include emissions associated with adjusted ownership share differentials reported by retail providers.

# ATTACHMENT D

## Decision of the California Public Utilities Commission and Attachment:

## California Public Utilities Commission / California Energy Commission Joint Proposed Electricity Sector Greenhouse Gas Reporting and Verification Protocol

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Decision **PROPOSED DECISION OF COMMISSIONER PEEVEY (Mailed 8/15/2007)**

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

| | |
|---|---|
| Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework and to Examine the Integration of Greenhouse Gas Emissions Standards into Procurement Policies. | Rulemaking 06-04-009 (Filed April 13, 2006) |

# INTERIM OPINION ON REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS IN THE ELECTRICITY SECTOR

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# INTERIM OPINION ON REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS IN THE ELECTRICITY SECTOR

## I. Summary

The California Public Utilities Commission (Public Utilities Commission) and the California Energy Commission (Energy Commission) recommend that the California Air Resources Board (ARB) adopt the proposed regulations contained in Attachment A to this order, as reporting and verification requirements applicable to retail providers and marketers in the electricity sector. These requirements would be adopted as part of ARB's implementation of Assembly Bill (AB) 32, which requires that statewide greenhouse gas (GHG) emissions be reduced to 1990 levels by 2020, and that ARB adopt regulations by January 1, 2008 regarding the reporting and verification of statewide GHG emissions.[7]

The proposed electricity sector reporting and verification protocol (Protocol) in Attachment A that we recommend to ARB would apply to all retail electricity providers in California, including investor-owned utilities (IOUs), multi-jurisdictional utilities, electric cooperatives, publicly-owned utilities (POUs), energy service providers (ESPs), and community choice aggregators (CCAs). The California Department of Water Resources (DWR) and other state agencies would be required to report the power that they generate or procure from entities other than a retail provider to serve their own loads. Because the Western Area Power Administration (WAPA) sells a small amount of power to end users in California, it would be requested to report as a retail provider under the recommended Protocol. Separate reporting requirements in Attachment A would apply to marketers that import power into or export power from California. The annual reports submitted in compliance with the recommended reporting Protocol would complement the electricity source-based reporting requirements that are being developed separately by ARB.

The Public Utilities Commission and the Energy Commission have developed the recommended reporting Protocol to collect the information that would be needed to track and verify GHG emissions attributed to the electricity sector under a load-based GHG regulatory approach. In addition, the Protocol provides for the collection of information from marketers that would be needed if a GHG regulatory approach that focuses on entities that deliver power to the California transmission grid (sometimes called a "deliverer" or "first-seller" approach) is adopted instead of a load-based approach. We take no position at this time on whether a load-based, first-seller, or some other approach should ultimately provide the framework for the electricity sector regulatory approach under AB 32.

[7] Section 38530(a). Unless indicated otherwise, citations to Sections refer to California Health and Safety Code sections added by AB 32.

The recommendations proposed in today's decision build upon the reporting protocols of the California Climate Action Registry (CCAR), as required by AB 32 (Section 3850(3)). Voluntary reporting to CCAR already encompasses most of the California electricity sector's GHG emissions. Our recommended reporting protocol is best regarded as an interim measure that refines and standardizes the CCAR conventions and applies them uniformly to all California retail providers. Implementing mandatory reporting for the entire industry is an important first step toward creating a comprehensive GHG regulatory framework. We anticipate that further refinements will be made once that framework is developed.

AB 32 requires that regulations adopted by ARB ensure that identified GHG emission reductions are "real, permanent, quantifiable, verifiable, and enforceable" by ARB. (Section 38562(d)(1).) To that end, Attachment A contains certain recommendations regarding the manner in which GHG emissions associated with owned power plants, purchases from specified sources, and wholesale sales are attributed to retail providers.

A particularly contentious issue in this proceeding has been whether and how to address transactions classified as "contract shuffling" in the context of the reporting and verification protocol. Contract shuffling refers to a situation in which a retail provider modifies its power contracts to make it appear that emissions have been reduced whereas in fact, emissions are unchanged. Opportunities and incentives to enter such transactions are a natural consequence of the state's limited jurisdiction within an electricity market that encompasses almost the entire western United States (as well as parts of Canada and Mexico). California is particularly vulnerable to contract shuffling because on average about half of the emissions associated with our electricity consumption are from imported power. Establishing a cap on GHG emissions that includes other western states, as envisioned by the Western Regional Climate Initiative, would diminish these incentives and opportunities. A cap spanning the entire Western Electricity Coordinating Council (WECC) region would eliminate them almost entirely.

We intend to consider the issue of contract shuffling in depth in the next phase of the proceeding, which will focus on developing recommendations on the regulatory approach for the electric sector. We will be better situated to develop policies related to this issue once the question of the overall regulatory approach has been resolved, and when the Western Regional Climate Initiative has progressed further. However, the issue of contract shuffling is not entirely distinct from the reporting and verification policies that are the focus of this decision. AB 32 requires that emissions reductions that are counted toward the state's GHG reduction goals be "real." By definition, contract shuffling does not yield real emissions reductions. The reporting and verification protocol should therefore not recognize apparent emissions reductions resulting from such transactions. The complexity of energy markets makes it difficult to discern all instances of contract shuffling or to determine the motivation for a particular transaction. Therefore in this decision we focus exclusively on a class of transactions that are most likely to yield GHG reductions that are not real. These transactions involve sales of energy from high-emitting generating units that are offset by purchases from nuclear and hydroelectric plants. As explained in Section V.A such transactions would only result in real emissions reductions in extremely unusual circumstances. To accommodate such exceptional cases, the reporting and verification protocol allows for review of the emissions factors applied to individual transactions.

We take this limited action to address contract shuffling in today's decision for two reasons. First we wish to send a clear signal that we intend for California's system of GHG regulations to provide real emissions reductions. Ensuring the environmental integrity of our regulations is critical in order to position California to be able to trade with other states, regions and nations. Second, we wish to convey to retail providers that contract shuffling is not a viable strategy to meet their (yet to be determined) GHG emissions reduction targets under AB 32. Moreover, by creating a deterrent to the most conspicuous form of contract shuffling at this time, we also seek to avoid a situation in which retail providers have amassed significant paper reductions by the time that we consider this issue in greater depth in the context of developing the compliance regime.

We recommend that, when the source of a power purchase is not identified, ARB use a regional default emission factor of 1,100 pounds of carbon dioxide equivalent emissions per megawatt-hour (lbs $CO_2e$/MWh). This value would be used for purchases from both in-state and out-of-state unspecified sources, and should be in effect until a regional tracking system for GHG emissions from electricity is implemented.

The recommendations we adopt today apply to the reporting and verification of GHG emissions for 2005 through 2008. In addition to modifications to the default emission factors once a regional electricity tracking system is implemented, modifications to other aspects of the reporting protocol may be warranted for future years once the type of GHG regulation for the electricity sector is determined. We recommend additionally that a comprehensive review of GHG reporting requirements for the electricity sector be undertaken in 2010, so that updated reporting requirements can be in place prior to the commencement of the GHG regulatory scheme in 2012.

We strongly support the call made by several parties in this proceeding for a multi-state regional GHG reporting and tracking system. A regional solution to reporting and tracking would greatly increase the accuracy of GHG reporting in California and could decrease the reliance on default emission factors. We urge ARB to lead California's participation in a regional effort to develop and implement such a system promptly, as is the intent of the Governors' Western Climate Initiative. The Public Utilities Commission and the Energy Commission are prepared to assist in this effort.

## II. Background

AB 32 requires that, on or before January 1, 2008, ARB adopt regulations to require the reporting and verification of statewide GHG emissions and to monitor and enforce compliance with the program. (Section 38530(a).) The statute specifies that "statewide GHG emissions" includes the total annual emissions of GHG gases in the state. (Section 38505(m).) While certain language in AB 32 focuses on "electricity consumed in the state," we interpret the statutory definition of "statewide GHG emissions" to include emissions from electricity generated in California and exported from the state, in addition to electricity consumed in the state.

Decision (D.) 07-05-059, the second order amending the Order Instituting Rulemaking (R.) 06-04-009, and the Scoping Memo for Phase 2 of this proceeding provide that the Public Utilities Commission, in collaboration with the Energy Commission, will provide recommendations to ARB regarding, among other things, the reporting and verification regulations that ARB will adopt pursuant to AB 32.

The Public Utilities Commission and the Energy Commission jointly held a workshop on April 12 and 13, 2007 that addressed GHG reporting and verification issues, among other subjects. Based on information presented at that workshop, subsequent ARB workshops, and existing reporting protocols of the Energy Commission and the California Climate Action Registry, staff from the two agencies (Joint Staff or Staff) developed a Joint Staff proposal for an electricity retail provider GHG reporting protocol. Pursuant to a June 12, 2007 ruling by the Administrative Law Judges (ALJs), parties were invited to comment on the Joint Staff proposal. The ALJ ruling also asked parties to comment, among other things, on whether modifications to the Joint Staff reporting proposal would be needed to support a deliverer/first-seller GHG regulatory structure for the electricity sector.

Today's decision is based on information presented at the April 12 and 13, workshop; the Joint Staff reporting proposal; materials incorporated into the record by ALJ rulings dated June 18, June 27, and July 19, 2007; and comments filed by the parties in this proceeding.

## III. Overview of Tracking of GHG Emissions in the Electricity Sector under a Load-based Regulatory System

This section provides a general description of the method that we recommend to ARB for verifying GHG emissions in the electricity sector if a load-based regulatory approach is adopted for the electricity sector. Subsequent sections address the needed reporting and verification provisions in more detail.

ARB plans to collect net generation, fuel consumption, and GHG emissions data from all generating facilities in California with a nameplate generation capacity of one or more megawatts (MW). The reporting and verification protocol we recommend for the electricity sector would complement ARB's source-based protocol. As the regulatory framework for the electric sector has yet to be determined, our current objective is simply to ensure that the initial reporting protocol yields data that will support alternative approaches. We take no position at this time on whether a load-based, first-seller, or some other approach should ultimately provide the framework for the electricity sector regulatory approach under AB 32.

A load-based tracking approach would assign responsibility to each electricity retail provider for the GHG emissions associated with the electricity generated to serve its load. Consistent with this approach, the retail providers would report information regarding their procurement of electricity from various types of sources, including the following:

- o Owned generation, which includes partial ownership (in-state or out-of-state),
- o Contracts for power purchases tied to specific power plants,
- o Contracts for power purchases tied to specific fleets of power plants,
- o Contracts for power purchases that do not specify the generation source(s), and
- o Purchases from the real-time market and the planned Integrated Forward Market of the California Independent System Operator (CAISO).

ARB would then attribute GHG emissions to the power procured by the retail provider, based on emissions information from a variety of sources:

- o For owned in-state generation and power contracts with specified in-state sources, emissions information would be available from ARB's source-based reporting regulations.
- o ARB would obtain emissions information regarding other specified sources from reports that those plants may submit voluntarily, or from power plant data submitted to federal agencies.
- o For procurements from unspecified sources, ARB would develop default emission factors and/or supplier-based emission factors, as detailed in Section V.C of this order.
- o ARB may need to make certain adjustments to ensure that attributed emissions are accurate and that reported emission reductions are real, as discussed in Section V.A of this order.

To allow assessment of emissions due to electricity generated in California and exported from the state, retail providers would be required to report information regarding their wholesale power sales, including exports. Marketers would similarly be required to report information regarding their exports from California.

Multi-jurisdictional utilities would be required to report information for their operations that provide electricity to service territories that include end use customers in California. ARB would attribute GHG emissions to their California operations based on the proportional share of their electricity sales in California.

Lastly, marketers would be required to submit information regarding imports of electricity into California, which would be needed if a deliverer/first-seller approach is adopted.

## IV. Definitions, Criteria for Establishing GHG Reporting and Verification Protocols, and Covered Entities

### A. Definitions

Most of the definitions recommended in the Joint Staff proposal are not disputed by parties. We make several changes to the definitions in Attachment A in response to parties' comments and to provide greater clarity.

The California Municipal Utilities Association (CMUA) believes that the Staff report would expand the definition of "leakage" beyond that intended by AB 32 and improperly uses it within the Staff's definition of "contract shuffling." CMUA points out that AB 32 defines "leakage" as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." We address CMUA's concerns regarding the Joint Staff's proposal regarding contract shuffling in Section V.A. below. We do not adopt the Staff's proposed definition of "leakage," since that term is defined in AB 32. Nor do we see a need to adopt a definition of the term "contract shuffling," since that term is not used in Attachment A.

The Division of Ratepayer Advocates (DRA) recommends that the definitions for "emission factor" be expanded to include all GHG emissions because, in DRA's opinion, AB 32 requires that all retail electricity providers measure GHG emissions related to their consumers' electricity consumption, and because Section 38505(g) defines GHG to include more gases than just carbon dioxide ($CO_2$). DRA is correct that AB 32 defines GHGs to include six gases: $CO_2$, methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons. ARB will assign emission factors that reflect all six gases. While we clarify the definition of emission factors in Attachment A, we see no need to list the six gases in this definition.

For clarity regarding reporting requirements, we add certain definitions of terms that are used in Attachment A. We also delete certain definitions that were in the Joint Staff proposal, but which are not needed in the Protocol recommended in Attachment A.

### B. Covered Entities

The Joint Staff recommends that all retail providers of electricity in California be required to report under the recommended protocol. This encompasses all IOUs, ESPs, CCAs, POUs, and WAPA. As pointed out by the Natural Resources Defense Council and Union of Concerned Scientists (NRDC/UCS), DWR procures electricity to meet the needs of the State's water projects, but was not covered in the Joint Staff's proposal. Section 38530(b) requires that any reporting system adopted by ARB account for all electricity consumed in the State. The reporting Protocol that we recommend would require that DWR, as well as any other state agencies that generate or procure power from entities other than retail providers to meet their electricity needs, report using the retail provider portion of the reporting Protocol in Attachment A.

As a federal agency, WAPA should be requested to report under the Protocol. If WAPA declines to report, ARB should consider requiring end use customers of WAPA to report their receipts of electricity from WAPA.

Several parties recommend that marketers be required to report information regarding power that they import into California. We agree that such a reporting requirement would be helpful, particularly if a deliverer/first-seller regulatory approach is adopted. In addition, marketers should be required to report information regarding power that they export from California. These reporting requirements are specified in the marketers section of the reporting Protocol in Attachment A.

## V. Attributing GHG Emissions to Various Sources of Electricity

For purposes of reporting GHG emissions, the Joint Staff explains that the sources of power used to meet retail load fall into two categories: power that can be tracked to a specific facility (specified sources) and power that can only be tracked to a mix of power plants at one of various geographic levels (unspecified sources).

In order to assign responsibility for GHG emissions to retail providers, the appropriate emissions factor of each source of power must be determined. This emission factor multiplied by the amount of power generated to deliver the power received from the source will yield the gross amount of emissions to be attributed to the retail provider, which must be adjusted for wholesale sales to other entities. For specified sources, the plant-specific emission factor will be established by ARB based either on its own source-based reporting requirements or on data filed with the United States Environmental Protection Agency (EPA) or the Energy Information Agency (EIA). Suppliers that own their own fleet of generation resources may also obtain supplier-specific emission factors from ARB. For unspecified sources, estimated default emissions factors must be established.

### A. AB 32 Requires Accurate Reporting and Real Emissions Reductions that Are Enforceable by ARB

AB 32 requires ARB to adopt, on or before January 1, 2008, regulations to govern the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program. (Section 38530(a).) The reporting system adopted by ARB will be used to ensure that the identified GHG reductions are "real, permanent, quantifiable, verifiable, and enforceable" by ARB. (Section 38562(d)(1).) The reporting and verification system is central to determining individual entities' compliance with AB 32 and ensuring that the overall goals of AB 32 are achieved.

Retail providers balance a variety of objectives when procuring electricity. In addition to accommodating the variability of electricity demand that occurs from hour to hour, retail providers must factor in price volatility of underlying fuel sources, reliability of power sources, various Public Utilities Commission and Energy Commission program requirements (including Renewable Portfolio Standard (RPS), energy efficiency, and resource adequacy requirements), and general market volatility.

As a result, retail providers use a variety of complex commercial arrangements to procure power.

As Staff notes, these complex arrangements may make it difficult to determine the true effect that a procurement choice can have on a retail provider's GHG emissions. With the exception of source-specific contracts, electricity can be resold and repackaged multiple times before a retail provider purchases it. Even with a source-specific contract, other power may be substituted should the need arise. Such transactions make it difficult to track the electricity to its original source. Therefore, default emission factors must be established based on analysis of sources in a region.

### 1. Staff's Proposal to Ensure Real GHG Emission Reductions

Staff is concerned that, with the advent of GHG regulation to meet AB 32 requirements, a retail provider may modify its power contracts or purchases from CAISO markets and report its power acquisitions in a manner that would make it appear that the retail provider has reduced its GHG emissions when, in reality, the same amount of GHG emissions is occurring as before.[8] In its report, Staff provides an example, as follows. A California retail provider that has an ownership share in an out-of-state high GHG-emitting generating facility could sell that power to an out-of-state entity which, in return, sells to the California retail provider the same amount of power but obstensibly from a lower GHG-emitting source. If the retail provider's emissions are calculated based only on the purchase from the out-of-state entity, it could appear that the California retail provider has reduced GHG emissions. However, in reality, the same amount of GHG would be emitted into the atmosphere.

Staff reports that there is sufficient relatively low-GHG generation (including from natural gas-fired plants) available outside of California such that, if such contractual power swap arrangements were treated as reducing the California retail provider's GHG emissions, California retail providers could be deemed to largely meet the statutory GHG reduction targets but with no reductions in the total GHG emissions due to electricity generation in the WECC region.

The Joint Staff recommends that conditions be imposed on the recognition of facility-specific purchases for GHG accounting purposes to ensure that the power purchase truly modifies generation from the specified plant. The Joint Staff explains that one acceptable condition may be the existence of a long-standing contractual relationship between the retail provider and a specified plant. At the same time, the Joint Staff cautions that new contracts for existing low- or zero-GHG plants are unlikely to yield real reductions in GHG emissions, commenting that "there is little reason to believe that an agreement between a retail provider and an existing plant will induce generation that would not have occurred anyway." Staff states that any new plants owned or partially-owned by a retail provider should be viewed as being used to meet

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[8] Joint Staff refers to this concern as "contract shuffling."

the retail provider's load. The new power plants would reduce overall demand for existing generation sources and, if the new power plant has lower GHG emissions than the previous source the retail provider utilized, a real reduction in GHG emissions would result. The Joint Staff also suggests that a long-term power contract signed between a retail provider and a developer prior to a plant's construction would be sufficient to demonstrate a causal link between the retail provider and the addition of the specified new capacity.

### 2. Positions of the Parties

Several parties object to the Joint Staff's proposal to restrict the manner in which emission factors would be attributed to power that retail providers report as being received or sold from specified sources.

Several parties contend that the Joint Staff's proposed conditions regarding the treatment of emissions for power received or sold from specified resources are not consistent with AB 32. In these parties' opinion, the intent of AB 32 was to reduce the carbon footprint of electricity consumed in California. They recognize that the intent of AB 32 is to mandate reductions in GHG emissions, but they argue that AB 32 does not support the Joint Staff's attempt to limit contract shuffling. In these parties' opinions, AB 32 does not purport to regulate GHG emissions from generation outside California if the electricity is not consumed in California. These parties argue that AB 32 prevents ARB from regulating out-of-state GHG emissions not caused by electricity consumed in California. Parties also argue that it would be impermissible to regulate a California retail provider that sells a higher-emission resource and replaces it with an existing lower-emission resource. They assert that, as a state law, AB 32 cannot and should not affect the carbon reduction strategies of other states.

Several parties interpret the Joint Staff proposal as an attempt to disapprove or prohibit certain contracts. They interpret the Staff reference to limiting "claims" to existing low- and zero-GHG resources as a proposal to restrict their ability to enter into contracts with existing resources.

Parties argue that limiting facility-specific contracts would be contrary to criteria proposed by the Joint Staff. In particular, they assert that the Joint Staff's limits would have the unintended consequence of preventing California utilities from seeking and procuring existing renewable resources outside California.

CMUA and Morgan Stanley Capital Group Inc. (Morgan Stanley) argue that contract shuffling is not a large concern because of Senate Bill (SB) 1368 and other states' RPS goals. These parties contend that SB 1368 places significant restrictions on the procurement of unspecified resources to meet a retail provider's load.

### 3. Discussion

There are several potential types of contractual arrangements that could be used to show "paper" emission reductions, but which would not actually reduce GHG emissions. A California retail provider could sell power from its owned (or partially-owned) high-GHG generation facility to an out-of-state entity and simultaneously purchase power from a lower-GHG specified source, or from an unspecified source with a lower default emission factor. If left unchecked, incentives for this type of contract shuffling would be strongest for out-of-state high-GHG plants in either a load-based or first-seller GHG regulatory structure, and also for in-state high-GHG plants in a load-based GHG regulatory structure if the retail provider is not responsible for emissions associated with exports. If the nature of such a contract shuffle is not recognized, the retail provider's reported GHG emissions would decline but, in reality, the high-GHG power plant would still be operating, making it unlikely that the total amount of GHG emissions within the region had actually been reduced. A source-based GHG regulatory system throughout the WECC region would greatly limit, if not eliminate, the incentives to engage in this type of contract shuffling.

In a similar strategy that could show illusory emission reductions, a California retail provider that usually purchases power from a relatively high-GHG source (specified or unspecified) could buy power instead from another existing source with a lower GHG emission factor, thus appearing to reduce its GHG emissions. If the relatively high-GHG source continues to operate, total GHG emissions may remain at previous levels, with no real reduction in GHG emissions. As in the previous example, such opportunities, if unchecked, would provide the strongest incentives for contract shuffling if the relatively high-GHG source is out-of-state. This is because GHG emissions from this source no longer would have to be reported to ARB, leading to an apparent reduction of California electricity sector emissions.

We agree with Staff that, through selling or otherwise not taking receipt of power from their high-GHG facilities or power purchase contracts and replacing that power with existing low-GHG resources that would have operated anyway, California retail providers could attempt to receive credit for GHG reductions that are not real, as illustrated by the above examples. We believe that such attempts to transfer responsibility for existing emissions would be counter to the intent of AB 32. If other states in the WECC region were to adopt GHG regulations, such attempts might be less problematic since the relatively higher-emitting sources would become subject to another state's GHG regulations. However, since there is no regional or federal GHG regulatory system in place at this time, ARB should send a strong signal now to discourage contract shuffling, by not permitting the apparent emissions reductions to be counted under the reporting and verification protocol. Broader policy questions concerning contract shuffling and other measures that might be taken to minimize and mitigate various forms of this practice should be addressed more completely in the context of the overall compliance framework. By employing an interim deterrent, we seek to avoid a situation in which retail providers could accumulate significant apparent emissions reductions that are highly unlikely to be recognized in the eventual compliance regime.

In their comments, several parties argue that AB 32 does not provide any authority to deal with the problems that the Joint Staff identify as contract shuffling. One of the arguments made is that contract shuffling is not necessarily "leakage" as defined in the statute. (Section 38505(i).) However, while minimizing leakage is one of the goals of the statute (Section 38562(b)(8)), the statute also requires ARB to ensure that the "greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable" by ARB. (Section 38562(d)(1).) We propose that ARB adopt verification conditions that would prevent the attribution to retail providers of GHG emission reductions that are not real. Accordingly, such regulations are within the scope of the statutory authority.

Several parties object to the Joint Staff report's concept of rejecting "claims" to specified sources. We think that the language concerning "claims" used in the Joint Staff report caused unnecessary confusion and accordingly we do not use this terminology in the proposed rules. The question we are dealing with here is whether a shift in the reported source of power would result in real emission reductions. If not, the retail provider should not get credit for illusory emission reductions.

While the Southern California Public Power Authority (SCPPA) raises such a concern in its comments, the regulations we recommend to ARB would not cause any quantity of electricity to go unreported. Nor would they regulate out-of-state facilities selling electricity for consumption outside of California, as claimed by CMUA. Rather, these regulations would specify the level of emissions that ARB would attribute to power obtained by a California retail provider in a manner that would ensure that any identified GHG reductions are real, as required by AB 32. These regulations are not intended to affect the carbon reduction strategies of other states, only to ensure that California's carbon reduction strategies produce real reductions in carbon emissions.

The recommended reporting regulations would not prohibit parties from entering into contracts for the supply of electricity that they are otherwise permitted to enter into, a concern raised by the Los Angeles Department of Water and Power (LADWP). What these regulations would establish is the level of GHG emissions that would be attributed to electricity procured pursuant to reported contractual relationships. To avoid the mistaken identification of GHG reductions that are not real, in some instances these regulations would require that the level of emissions attributed to certain power for the purpose of GHG accounting be different than the level of GHG emissions that occurs from the source specified in the contract.

Some parties object to a suggestion in the Joint Staff report that certain contract shuffling problems might be dealt with by treating some purchases from specified in-state generating resources differently than purchases from specified out-of-state resources. We agree with these commenters that that suggestion should not be pursued further.

The methods that we recommend to ARB for attributing GHG emissions related to the purchase of power from existing specified sources and the sale of power generated by owned power plants would allow more accurate tracking of GHG emissions and avoid the calculation and attribution of GHG reductions that are not real. These recommendations are also discussed in Sections V.B.2 and V.D.1 of this order, and the recommended reporting and verification protocol is set forth in Attachment A.

In verifying GHG emissions associated with owned or partially-owned power plants, we recommend that ARB consider first the GHG emissions related to the full ownership share of the output of the plant. Under a load-based GHG regulation approach, once emissions associated with the retail provider's ownership share of the plant's generation are known, ARB would subtract emissions attributed to power sales from the plant[9]. Emissions attributed to sold power that is delivered to a point of delivery in California for use to serve California load would be subtracted, based on the emissions profile of the power plant, since under AB 32 those emissions are the responsibility of the retail provider using the power to serve its load (as discussed further in Section V.D of this order).

For other sales, the attributed emission factor may depend on the reason for the sale, to prevent the reporting of emission reductions that are not real. ARB would attribute emissions to the sale based on the emissions profile of the power plant under the following circumstances, because they would not raise contract shuffling concerns:

- If the power could not be delivered to the retail provider or the retail provider had surplus power during the hours in which it was sold, or,
- If the power was from a California-eligible renewable plant with WREGIS certificates transferred to the buyer along with the power.

For sales under other circumstances, we recommend that ARB attribute emissions to the sale using an average emission factor of the retail provider's sources that were available for unspecified sales (described in Section V.D.2 of this order). This recommendation would apply only to the portion of the sale that exceeds ten percent of the retail provider's proportional ownership share of the generation, in recognition of the fact that the retail provider may need some flexibility in receiving power from the power plant in order to meet its operational needs.

For GHG accounting purposes, we view contractual arrangements in which the purchasing party has a contractual entitlement to a specified percentage of the output of a power plant as comparable to an ownership interest in the power plant. The incentives for selling the power from such plants, if they have relatively high GHG emissions, would be the same as for partially-owned plants. Thus, for GHG reporting purposes, retail providers should report power they receive or sell from such plants as being from partially-owned plants, and ARB should attribute emissions to the purchases and sales from those plants on that basis.

As an additional step to ensure that reported emission reductions are real, the proposed decision recommended that ARB attribute emissions associated with any purchases through new contracts with existing specified sources based on the default emission factor of the region in which the specified source is located. However, based in large part on comments on the proposed decision, we conclude that the largest

[9] For power plants located in California, emissions associated with exports are not subtracted, since AB 32 requirements encompass exports of power generated in California.

concern about contract shuffling associated with new contracts with existing sources arises with new contractual arrangements with existing nuclear or large hydro plants.[10]

Due to the nature of nuclear and large hydro plants, they almost always are operated at the full capacity of which they are capable. Therefore, if a retail provider buys additional power from such a plant to replace power previously obtained from another source (e.g., from a high-GHG source), it is logical to conclude that the nuclear or large hydro facility is not producing more power to fulfill the new contract. Rather, it is most reasonable to conclude that the entity that previously obtained that power from the nuclear or hydro facility will have to obtain replacement power. Therefore, the real reduction in GHG emissions is not the difference between the emissions rate of (i) the old (high-GHG) source and (ii) the nuclear or hydro source. Rather, the real reduction in GHG emissions is the difference between the emissions rate of (i) the old (high-GHG) source and (ii) the emissions rate of the replacement power procured by the party that previously received power from the nuclear or hydro source. To best reflect that difference, the recommended protocol ascribes to the power purchased from the existing nuclear or large hydro power plant the default emission factor for the region in which the plant is located.[11]

We are less convinced that operations of other types of existing power plants could not be improved, in terms of reducing GHG emissions on a regional basis, through contractual modifications. For example, shifting generation from less-efficient to more-efficient natural gas-fired power plants may become more advantageous with the recognition of the value of GHG emission reductions. Additionally, limiting the attribution of default emission factors to new contracts with existing nuclear and large hydro plants would encourage greater contracting flexibility for ESPs and other market participants that may rely more heavily on short-term contracts. Further, emission factors of existing natural gas facilities are closer to the regional default emission factors, so use of regional default emission factors would have relatively small impacts on attributed emissions. For these reasons, we reject the recommendation in the proposed decision that would attribute regional default emission factors to all purchases through new contracts with existing specified sources.

We make these recommendations because it is our opinion that the high demand on all resources in the WECC region makes it unlikely that replacing power from relatively high GHG-emitting resources with power from existing lower GHG-emitting resources would result in operational changes for the resources or in lower total GHG emissions in the WECC region. The emission attribution procedures we recommend help ensure that GHG reductions that ARB may calculate as result of a retail provider replacing generation from a high GHG-emission source with lower GHG-emission purchases are based on a convincing showing that real GHG emission reductions were achieved.

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[10] By "large hydro plant," we mean any hydroelectric plant larger than 30 megawatts that is not a California-eligible renewable plant.

[11] As discussed in Section V.C, we recommend that ARB use a uniform regional default emission factor at this time. We expect that default emission factors for each region will be set at a later date.

PG&E and other parties argue that AB 32 does not allow the attribution of emissions other than those actually occurring at a contracted resource, citing Section 38530(a), which requires ARB to adopt regulations for the "reporting and verification" of GHG emissions from GHG sources. This argument ignores a key portion of Section 38530(a), which provides that the reporting and verification regulations to be adopted by ARB are to "monitor and enforce compliance with [California's] program" to reduce GHG emissions. A key element of this program is that the GHG "emission reductions achieved are real…" (Section 38562(d)(1).) As described above, a reporting and verification regime that allowed a retail provider to reduce the emissions attributed to it through contractual changes without there being actual reductions would violate this requirement. The methods that we propose to attribute emissions in certain instances according to historical contractual arrangements rather than the sleight of hand that Staff calls contract shuffling would ensure that the reporting entity does not receive improper credit for emission reductions that are not real, consistent with Section 38562(d)(1). Accordingly, we reject this argument.

SDG&E and CMUA argue that the definition of "statewide greenhouse gas emissions" in Section 38505(m) precludes ARB from enacting regulations that would attribute to power delivered to California a GHG emissions rate different than the emissions rate of the generation facility specified in the contract under which the power is delivered. However, Section 38505(m) does not refer to the emissions of specific generation facilities or how to calculate the emissions from specific facilities. Instead, it generally refers to the "emissions of greenhouse gases from the generation of electricity delivered to and consumed in California . . . whether the electricity is generated in state or imported." The apparent purpose of the cited language is to ensure that imported electricity is not omitted in calculating the overall GHG emissions for which California is responsible. The regulations we propose would achieve this purpose, while also ensuring that reported emission reductions are real. Accordingly, we decline to conclude that the general language contained in Section 38505(m) overrules the requirement of Section 38562(d)(1) that emission reductions be "real."

Sempra Global (Sempra) objects that there is nothing in the record to support the conclusion in the proposed decision that "it is unlikely that new contracts with existing generation sources would produce real reductions in GHG emissions, since most, if not all, of existing power plants would run the same regardless of any new contract." With the revisions we make to the recommended Protocol, the use of default, rather than plant-specific, emission factors would be limited to purchases under new contracts with existing nuclear and large hydro plants. As explained above, these plants usually are operated at full capacity to the extent possible, so that changes in contractual arrangements for their output would not change GHG emissions. If an entity believes that use of default emission rates does not recognize a real reduction in GHG emissions, it can make its case to ARB, as provided in Section 2.14 of the Protocol in Attachment A, that a different emissions factor should be used so as to reflect the actual reduction in GHG emissions.

Sempra argues further that, "Because the proposed rule [in the proposed decision that would assign default emission factors to purchases from certain existing generation facilities] would have the effect of directing that wholesale sellers of electricity from existing units could only contract with their current counterparties, the rule could easily be found to unlawfully interfere with interstate commerce. Also, limiting the seller's pool of potential buyers to a single party could be viewed as creating an unlawful restraint on trade." However, the regulation we are proposing today, as compared to the rule proposed in the proposed decision, would apply default emission factors to a much smaller group of existing generation facilities. Furthermore, nothing in the regulation would require wholesaler sellers of electricity from existing power plants to contract with their current counterparties.

One impact of establishing a GHG cap that applies only to California is that a low-GHG emitting power plant may be a more valuable source of electricity to a California retail provider than it is to a retail provider from a state that has no GHG cap. Thus, under the proposed regulations, there may be a financial advantage for the seller of electricity from an existing power plant to sell to certain California retail providers, rather than to a retail provider from another state. However, this advantage would apply equally to sellers of power from existing low-GHG plants whether they are located inside California or out of state. Thus, there is no discrimination against interstate commerce. These regulations, of course, may have an incidental impact on interstate commerce, just as different minimum wages in different states may have an incidental impact on interstate commerce; but it is not unlawful for a state to establish regulations that have an effect on interstate commerce.12

As for Sempra's argument concerning restraint of trade, also made by Independent Energy Producers Association (IEP), these parties provided no citation to any particular anti-trust law that the proposed ARB regulations might violate. Indeed, we are not aware of any situation where a state law or regulation that requires private parties to behave in a certain way has been held to violate the anti-trust laws. Here, the proposed regulations would require the covered entities to comply with the ARB's reporting requirements.

IEP argues that there may be a taking if the GHG regulations strip away the economic value of the environmental attributes (i.e., low GHG emissions) associated with a particular power plant, by using a default emission factor in

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[12] In essence, Sempra's argument is that it may be disadvantaged because existing low-GHG emission power plants may not be able to get the full economic benefit created by AB 32's GHG cap. This argument has by and large been eliminated by our recommendation to narrow the use of default emission rates to purchases under new contracts where the electricity is generated by existing nuclear or large hydro facilities. (And even as to those facilities, the default rate would not apply if the purchaser can show a real reduction in GHG emissions.) But to the extent that some generator still might not realize the same economic benefits as a result of the implementation of AB 32 as the owner of a new plant, this would still only establish that two differently situated entities have received different financial benefits as a result of the new law. Sempra has made no showing that this would illegally discriminate against interstate commerce or otherwise be illegal.

calculating emissions. This argument ignores the fact that the economic value to which IEP refers (the value of a power plant with low GHG emissions under a GHG regulatory scheme) is created by that regulatory scheme. Therefore, creating this regulatory scheme does not deprive the owner of anything that was already owned.

CMUA argues that the recommended reporting protocols may result in a regulatory taking requiring the payment of compensation. It discusses the situation of a California retail provider that owns a share in a high-emitting GHG power plant. CMUA contends that, in order to reduce its GHG emissions, that retail provider would have to sell its share in the power plant, or lay-off the owner's proportional share of the power. CMUA apparently argues that these would be the retail provider's only options because it could not get credit for reducing GHG emissions by buying power from an existing low-GHG power plant. Due to revisions that we make in the protocol recommended in the proposed decision, purchases from many existing lower-GHG power plants would allow the retail provider to show lower GHG emissions. But even if this change were not made in the protocol, the retail provider would still have the option of buying low-GHG power from a new power plant, or using allowances to offset its emissions. Only the reporting protocol is now at issue. Regulations that ARB will regarding, for example, the distribution of allowances (e.g., whether auctioned or allocated for free, and if so how) and the rate at which any particular retail provider will be required to reduce its GHG emissions, have not yet been determined. Therefore, it is premature to argue that these reporting protocols would have the particular economic impact predicted by CMUA. Furthermore, even if a retail provider were to be required to sell its share in a power plant to achieve AB 32 compliance, the owner would not be deprived of all economic use of its property, as CMUA contends, if someone would be willing to buy that share in the power plant. CMUA does not explain why the owner could not sell its share to an entity not subject to California's GHG controls. Nor does CMUA cite any cases holding that there is a regulatory taking if a pollution control requirement causes an owner of a plant to shut it down entirely.

CMUA also argues that there would be a regulatory taking if a power plant owner has to sell its ownership share or lay off its share of the power, because that would "interfere with the owner's reasonable investment-backed expectations whereby the owner could not have contemplated that contingency years ago during the initial investment." As explained above, these are not the only possible ways of that the owner could deal with the high-GHG emissions of a coal plant. Moreover, we are not aware of, and CMUA does not cite, any case where a requirement that an owner of power plant reduce pollution has been held to be a regulatory taking because that requirement has reduced the value of the power plant and the owner had no expectation that it would have to meet those particular pollution requirements when it invested in the power plant.

CMUA and NCPA seek clarification as to how the Protocol would treat emissions associated with power that is generated by a retail provider outside of California and also delivered and consumed outside of California. They take the position that emissions associated with such power should always be excluded from the retail provider's emissions profile for California. We agree that the amount of such power should be subtracted from the total amount of power generated and purchased by that provider. However, to prevent the counting of emission reductions that are not real, in a contract shuffling situation the Protocol would attribute to certain sales an emissions factor different than the emissions factor of the plant specified in the sales contract. In short, ignoring the retail provider's ownership share, and its corresponding share of sales from the plant, would defeat the regulations designed to prevent retail providers from showing GHG emission reductions that are not real.

### B. Specified Sources

A clear link between power delivered to a retail provider and a specific generating facility may exist if a retail provider owns or has an equity share in the facility or if it has a contract to purchase power from the facility. In some cases, certain utilities also receive specific allocations of power from federally-managed hydroelectric facilities. The GHG emissions associated with the delivered power can be determined with reasonable certainty based on these specified sources.

The Joint Staff describes that some contracts for purchasing power may describe a group of substantially identical resources at a single location as the source of power. We agree that, in that situation, it would be appropriate to treat the group of resources as a specified source for purposes of GHG accounting.

We address the determination of emission factors for power received from different types of specified sources in turn.

#### 1. Emission Factors for Owned or Partially-owned Specified Sources

In the Joint Staff report, Staff proposes that, for each wholly- or partially-owned generation source, the GHG emissions be based upon ARB-approved source data and, in the case of partially-owned generation, emissions should be allocated on the basis of the amount of electricity taken. Staff proposes, however, that reporting entities be required to provide explanations whenever the share of generation taken deviates from the ownership share, with the apparent view that adjustments may be warranted if it appears that the retail provider engaged in a form of contract shuffling in an attempt to reduce its GHG emissions responsibility.

LADWP seeks clarification on the appropriate emission factor for coal-based generation sources. As described above, ARB plans to establish emission factors for each wholly- or partially-owned generation source. We encourage LADWP to address its concerns through the appropriate ARB workgroup.

SCPPA objects to the use of ownership shares in calculating the GHG emissions to be attributed to a retail provider that owns a portion of a particular generating facility, stating that the attribution of emissions should be on the basis of actual deliveries. For reasons described in Section V.A., we recommend that ARB initially attribute emissions for owned and partially-owned power plants proportional to an entity's ownership share, adjusted for sales of power from the plant. As detailed in

Sections V.A and V.D, emissions would be attributed to the sale of power from the power plant, either by the retail provider or by the plant operator on behalf of the retail provider, based on the emission factor of the power plant for sales to another retail provider in California; if the power could not be delivered to or was not needed by the owner; and for sales from renewable resources. In those situations, the emissions associated with the generating facility would no longer be the responsibility of the reporting retail provider. Thus, the proposed regulations we recommend to ARB, taken as a whole, would not automatically result in a retail provider being responsible for all of the GHG emissions associated with its ownership share of a plant. However, the requirement that retail providers provide an explanation does permit ARB to act in particular instances to prevent the reporting of reductions in GHG emissions that are not real.[13]

No party raised concerns with Staff's recommendation that ARB establish GHG emission factors for owned and partially-owned generation. It is our understanding that ARB will determine the emission factors for owned and partially-owned generation based on either its source-based reporting protocol or data that generators are required to file with EPA or EIA. As explained above, if a retail provider has a contractual entitlement to a specified percentage of the output of a power plant, that source would be treated as a partially-owned plant for purposes of GHG accounting.

### 2. Emission Factors for Purchases from Specified Sources

For most power purchased from specified sources or obtained through exchange agreements from specified sources,[14] ARB will develop emission factors using information provided by in-state sources under ARB's source-based reporting requirements or, for out-of-state sources, from voluntary reporting by those facilities or from EIA and EPA data. We address the appropriate emission factors for attribution to purchases from various types of specified sources.

#### a) New Contracts with Existing Specified Sources

We recommend that ARB attribute emissions for purchases from specified sources based on emission factors of the specified source, except for new contracts with existing nuclear and large hydro power plants entered into on or after January 1, 2008. As described in Section V.A, in our opinion it is unlikely that such new contracts would produce real reductions in GHG emissions, since existing nuclear and large hydro power plants would be expected to run the same regardless of any new contract. Therefore we recommend that ARB attribute emissions to purchases made pursuant to new contracts with existing nuclear or large hydro plants based on the default emission factor for the region in which the plant is located.

[13] We note that, if a reporting retail provider sells its ownership share or the power plant does not operate, the retail provider would no longer be responsible for emissions from the power plant.

[14] We recommend that power obtained or delivered through exchange agreements be treated as a purchase or sale, respectively, for purposes of GHG accounting.

### b) Null Power from Renewable Resources

The term "null power" refers to electricity generated from a renewable resource for which the renewable and environmental attributes have been sold to another party. In D.07-01-039, the Public Utilities Commission decided that, for the limited purposes of the emissions performance standard, null power would be assigned the emissions value of the underlying renewable generation.[15]

Southern California Edison Company suggests that this approach be followed in our reporting recommendations to ARB. Center for Resource Solutions (CRS) proposes that null power be assigned system average emission characteristics. Sacramento Municipal Utility District (SMUD) proposes similarly that null power be assigned a default emission factor for the region in which the null power is generated.

Because California has not adopted Renewable Energy Credits (RECs), it would be premature to choose among these approaches at this time. The Public Utilities Commission is currently reviewing in R.06-02-012 the possible relationship between the renewable and environmental attributes embodied in a REC and the associated power. The attribution of GHG emissions to null power is an issue that will be dealt with as California decides whether to implement a REC program.

### c) Firming Power for Renewable Resources

Some contracts for the purchase of intermittent renewable resources such as wind and solar contain provisions that provide for the use of non-renewable resources to "firm" the power to meet the energy profile needs of retail providers. SMUD recommends that the non-renewable power used to firm intermittent renewable resources be assigned the carbon attribute of the associated renewable resource. SMUD states that this treatment would be consistent with how both Commissions have implemented the emission performance standard.

In D.07-01-039 we differentiated between two types of contracts with intermittent renewable resources that include firming energy: (1) contracts in which the firming resource is specified, and (2) contracts in which the firming resource is unspecified.[16] If the firming resource is specified, we determined that each individual resource must be compliant with the emissions performance standard adopted in D.07-01-039. In cases where the firming resource is unspecified, we limited the amount of substitute energy purchases from unspecified sources such that, "For specified contracts with intermittent renewable resources (defined as solar, wind and run-of-river hydroelectricity), the amount of substitute energy purchases from unspecified resources is limited such that total purchases under the contract (whether from the intermittent renewable resource or

[15] D.07-01-039 emphasized that the "determination on how to treat null renewable power and associated RECs is specific to the application of [the] adopted interim [emission performance standard]. This determination in no way guarantees that null renewable power will be assigned a zero or low GHG emissions value in the context of the Procurement Incentive Framework we are implementing in Phase 2 of this proceeding, or the statewide GHG emissions limit adopted by the Legislature in AB 32." (D.07-01-039, *mimeo*., at 127.)

[16] D.07-01-039, *mimeo*., at 134-151.

from substitute unspecified sources) do not exceed the total expected output of the specified renewable powerplant over the term of the contract."[17]

For the purposes of GHG reporting we recommend a similar approach, although our focus here is on annual GHG accounting rather than the generation and receipt of power over the life of the contract. If a contract with an intermittent renewable resource provides that firming energy will be provided, and if the total purchase under the contract is no more than the energy generated from the renewable facility in the reporting period, the firming energy should be attributed the same emission characteristics as the contracted renewable power plant and need not be reported separately. Any firming energy used beyond the amount of renewable power attributed to the reporting entity in WREGIS shall be reported consistently with the source of the firming power, i.e., generated from owned assets or purchased from specified or unspecified resources.

D.07-01-039 only dealt with long-term contracts and did not address how to treat circumstances where the retail electricity provider takes energy from a renewable resource and provides its own firming (in contrast to contracts in which the renewable energy seller does the firming). In these cases, emissions attributed to the renewable energy should be based on the characteristics of the renewable resource, and the firming energy should be attributed emissions based on its source, whether specified or unspecified.

#### d) Substitute Power

Contracts for power from a specified source may be structured such that the seller will fill in power from the specified plant with power from unspecified sources during planned and unplanned outages, start-ups, ramp rates, and other operating conditions that limit the plant's output. SMUD requests that substitute power provided under such contracts be attributed the emission factor of the contracted-for facility.

In D.07-01-039, we permitted contracts that would otherwise meet the emissions performance standard to provide for substitute energy purchases up to 15 percent of the forecasted energy production of the specified power plant over the term of the contract, provided that the contract only permits the seller to purchase system energy for substitute energy.[18] However, the emissions performance standard does not have the same purpose as the GHG reporting protocols. The emissions performance standard is a gateway standard that determines the types of long-term contracts that load serving entities are authorized to enter into. Even if a contract meets the emissions performance standard, ARB will need to identify the actual GHG emissions associated with the contract. Therefore, we recommend that all substitute power should have emissions attributed according to the source of the substitute power, whether specified or unspecified.

[17] *Ibid.*, at 146.
[18] *Ibid.*, at 148.

## C. Unspecified Sources

### 1. Default Emission Factors

The Joint Staff recommends that default emission factors be used for purchases from CAISO and for purchases from other unspecified sources, with separate default emission factors for the CAISO markets, purchases from other unspecified sources in California, purchases from unspecified sources in the Pacific Northwest, and purchases from unspecified sources in the Southwest. We recommend, instead, that a single regional default emission factor be used at this time for all purchases from unspecified sources.

#### a) Positions of the Parties

The default emission factor that Staff recommends for real-time purchases from the CAISO would be based on the emissions from hydro and natural gas units that can be ramped quickly. The Joint Staff report recommends a split of 90 percent gas and 10 percent hydro, resulting in a default factor of 900 lbs $CO_2$e/MWh. For the CAISO's Integrated Forward Market, the Joint Staff report expects that the market will include bids from all fuel sources but recommends a default emission factor of 1,000 lbs $CO_2$e/MWh, based on an assumption that natural gas will be the principal marginal resource.

Several parties urge adoption of a single default emission factor for the CAISO real-time and forward markets. Parties believe that different emission factors for the different pools would give market participants incentives and opportunities to enter into transactions that would undermine the efficient operation of electricity markets and would reduce the accuracy of these emission rates over time. The CAISO recommends that the Commissions adopt the same emission factor for the real-time market and the Integrated Forward Market when it becomes operational, and that the emission factor be between 1,000 and 1,100 lbs $C0_2$e/MWh.

The Joint Staff recommends that power from in-state unspecified sources be assigned the average 2005 emission factor for all California natural gas units. Staff reports the rounded emission factor to be 1,000 lbs $CO_2$e/MWh.

The Joint Staff recommends that default emission factors for power obtained from unspecified out-of-state sources be calculated for the Southwest and Pacific Northwest regions by first removing from the calculation all power purchased from specified sources (whether purchased by California entities or by entities in other states). A marginal method then would be used to calculate a regional average emission factor based on the historical and future probable dispatch patterns of the region. The Joint Staff report concludes that power from unspecified sources in the Southwest is 90 percent natural gas and 10 percent coal, with a weighted average emission factor of 1,075 lbs $CO_2$e/MWh. Based on its hybrid analysis, the Joint Staff report characterizes power from unspecified sources in the Northwest as 66 percent hydro and 22 percent natural gas, with small amounts of coal, nuclear, and renewables. On that basis, the Joint Staff obtained a Northwest default emissions factor of 419 lbs $CO_2$e/MWh.

Several parties dispute the default emission factor that the Joint Staff recommends for unspecified purchases from the Northwest. Some of these parties object that "unintended consequences" would occur because the Southwest default emission factor would be more than twice the size of the default emission factor that the Joint Staff recommends for the Northwest. These parties believe that this difference would provide incentives for parties to enter into transactions to hide high-emission sources located in the Southwest by moving power through California to the Northwest and then back into California. They suggest further that sellers could hide high-emission sources located in the Northwest by selling power from such sources into the Northwest power pool, with the power then resold as pool power, which would be attributed the default emission factor for the Northwest. In their view, either situation would reduce the accuracy of reported GHG emissions associated with serving California load and could also increase congestion on an already-constrained transmission system.

The Oregon Public Utility Commission and the Oregon Department of Energy (Oregon) and the State of Washington, Department of Community, Trade and Economic Development (Washington) express concerns that the methodology used in the Joint Staff proposal to develop a default emission factor for unspecified sources in the Northwest is inconsistent with the methodology currently used in Oregon and Washington. They contend, specifically, that the use of inconsistent methodologies in the Northwest and California would result in double-counting of hydropower. Oregon and Washington assert that hydropower in their states is used primarily to serve local or regional loads and that thermal power (coal and gas) is exported to serve load in California. In 2005, Oregon and Washington determined that the emission factor for the "net system mix" of electricity available for export from their region was 1,062 lbs $CO_2e$/MWh.

The Community Environmental Council and DRA propose interim Northwest default emission factors that are closer in value to the default emission factor that the Joint Staff proposes for the Southwest.

SCPPA argues that the Joint Staff's recommended method of basing the Northwest default factor, in part, on historical sales is not consistent with the "pure" marginal approach that the Joint Staff uses to calculate the default emission factor for the Southwest. SCPPA asserts that, if marginal economic dispatch modeling were used to calculate the Northwest default emission factor, this would indicate that the cheapest resources (hydro) would be used to serve native load in the Northwest and that more expensive resources (coal and gas) would be used to serve load in California. The resulting default emission factor would be larger than the Joint Staff recommends. SCPPA argues that this larger emission factor would eliminate incentives to hide higher-emission resources in the Southwest.

Calpine Corporation (Calpine) and NRDC/UCS urge adoption of higher default emission factors than those recommended by the Joint Staff, for both the Southwest and the Northwest, in order to encourage retail providers to use less power from unspecified sources and to encourage retail providers to contract with low- and zero-emission resources. Calpine recommends that default emission factors should represent emissions from the highest emitting unit in the region. NRDC/UCS recommend that the emission factor for all natural gas plants be set at the emission factor for the least efficient natural gas plant (1,640 lbs $CO_2e$/Mwh).

PG&E contends that insufficient information and data are presented in the Joint Staff's proposal to determine whether the proposed default emission factors are accurate, fair and verifiable. PG&E recommends that the reporting protocol be adopted without specific default emission factors and further workshops be scheduled to discuss calculation of emission factors.

#### b) Discussion

In setting a default emissions factor, we are persuaded to use a higher, conservative value. We agree that setting high regional default emission factors at this time for unspecified sources would further, rather than hinder, the goal of accurate reporting. As several parties, including Environmental Defense (ED), NRDC/UCS, and Calpine, point out, high default emission factors would help discourage high-emitting resources characterizing themselves as unspecified resources. Conservatively estimated default emission factors would encourage retail providers to specify their sources of power, thus furthering the goal of accuracy in reporting and tracking emissions data. They also would reduce contract shuffling opportunities and encourage retail providers to seek low-or zero-emission power sources. By contrast, as Calpine points out, low default emission factors may actually increase purchases from high-emitting resources by encouraging such sources to market themselves as unspecified sources. Calpine notes further that, if the default emission factor is lower than the actual emissions, the calculated emissions would be understated and, thus, emissions reductions would be overstated.

For these reasons, we recommend that ARB use a uniform regional default emission factor for purchases from unspecified sources, and that it be set at a level that reduces incentives to claim unspecified sources. We recommend that ARB use 1,100 lbs $CO_2e$/MWh as an interim regional default emission factor for purchases from unspecified sources. This value is close to the WECC regional average, and is higher than the emission factors for the most modern natural gas combined cycles and for hydropower and nuclear systems. Cleaner facilities and power systems will have the opportunity to have ARB verify and certify their emissions as a specified source with a known emissions factor.

As the Western states have now committed to developing a regional tracking system, California can best demonstrate its willingness to collaborate by not adopting at this time our own quantification system for default emission factors for imports from unspecified sources. Instead, we recommend that ARB use a uniform regional default emission factor for all unspecified sources on an interim basis. This would remove the incentive to arbitrage among regions based on differences in default emission factors, and, in this respect, would level the playing field among similar types of units in different regions. This interim default emission factor should be replaced with values derived from a common set of rules that will be developed by the Governors' Western Climate Initiative. We anticipate that this new tracking process will be in place before the start of the first GHG compliance year in 2012.

Several parties are concerned that the methods used to assign default emission values for unspecified sources should be consistent from 1990 forward so that artificial trends are not created solely due to changes in accounting conventions. ARB, Public Utilities Commission, and Energy Commission staffs have worked together to modernize the 1990 accounting to track as many specified sources, especially out-of-state coal units, as possible. This creates a greater degree of consistency than existed previously. But we cannot go back and create a 1990 Western regional tracking system to assign emissions to all power sources. Instead, we must rely on estimation techniques. Fortunately, interest in emissions related to electricity has been a topic of high policy interest starting in the late 1980s, so ARB can use information from that period to estimates 1990 emissions from the electricity sector.

We are aware that the choice of default emission factors may interact with computation of current emission responsibilities and proposals that some parties may have for allocation methods. This may be particularly true for those retail providers that currently purchase large amounts of power from unspecified sources. These issues will be addressed in the program design recommendations that we will send to ARB next year.

The proposed reporting and verification regulations in Attachment A are drafted to accommodate default emission factors that differ among the regions. Thus, if the regional collaboration yields region-specific default emission factors in the future, the regulations would not require modification in this respect. For now, however, we recommend a default emission factor of 1,100 lbs CO2e/MWh for use uniformly for purchases from unspecified sources in the Northwest, the Southwest, and California.

### 2. Supplier-Specific Emission Factors

The Joint Staff suggests that separate GHG emission factors may be appropriate for purchases from generators that sell power on an unspecified basis from their own fleets of generating units. Asset-owning or controlling sellers could document their sources of power to avoid attribution of a regional default emission factor. We agree that entities that own or control generating assets should be allowed to request that ARB develop and apply a supplier-specific emission factor for their sales from unspecified sources.

### 3. When to Calculate Default Emission Factors

The Joint Staff report describes that default emission factors could be estimated after a reporting period based on factors such as hydro availability and weather. Another option is to calculate ex ante emission factors that could be fixed at the start of a reporting period. The Joint Staff recommends that default emission factors be calculated on an ex ante basis to provide greater market certainty to retail providers.

Several parties support the Joint Staff recommendation in this regard. However, NRDC/UCS argue that ex post calculation of emission factors would provide a higher level of precision. In their view, if emissions factor were calculated ex post on an annual basis, retail providers would know the emissions factors established for the previous year and could use those emissions factors for planning purposes. They assert that, in most circumstances, emissions factors would be unlikely to deviate significantly from one year to the next. As a compromise, NRDC/UCS suggest that, to provide greater market certainty for retail providers, a hybrid approach could establish, on an ex ante basis, a range for allowable emission factors for each region. The specific emission factor would then be determined ex post on an annual basis, but would be limited by the adopted range.

We agree with Staff, as a general policy, that default emission factors should be calculated on an ex ante basis to provide greater market certainty to retail providers.

#### 4. Updating Default Emission Factors

The Joint Staff recommend that default emission factors be updated periodically, possibly every three years. Several parties urge more frequent updating of emissions factors. One party suggests that the frequency with which default emission factors should be updated be resolved after more of the structure of GHG regulation has been resolved.

We recommend that ARB update the data inputs for default emission factors on an annual basis, at least initially, so that ARB, the reporting entities, and other market participants can better understand the implications of the adopted GHG regulations. The interim default emissions factors described above should be updated when either a regional tracking method is operational or ARB has collected sufficient data to document the validity of a revised method.

### D. Retail Providers' Wholesale Sales

AB 32 governs statewide GHG emissions, including electricity consumed in California (including imports), and in-state generation that is exported out of California. In a load-based approach, retail providers would be responsible for the GHG emissions incurred to meet their retail load and for power generated in California and exported out of California. They would not be responsible in a load-based approach for the GHG emissions associated with power they sell or deliver through exchange agreements that is used to meet another retail provider's retail load. To avoid an incentive to mask exports by intermediary sales to marketers with a point of delivery in California, who could then export the power out of state, we require that retail providers document that in-state sales that are delivered to a point of delivery in California are in fact used to serve California load. Without such documentation, such sales would be treated as exports for purposes of GHG emission verification.

In a load-based approach, once a retail provider's own generation, power purchases, and related GHG emissions are known, GHG emissions must be attributed to the retail provider's wholesale sales and the emissions attributable to in-state sales must be deducted from the retail provider's emission responsibilities. The remaining GHG emissions represent the power used to serve the retail provider's in-state load and any sale of power that was exported from the state.

### 1. Sales from Specified Sources

Retail providers may make sales from specified sources or deliver power from specified sources through the terms of an exchange agreement. If delivered to a counterparty located in California for use in meeting California load, the corresponding emissions would be removed from the provider's GHG responsibility. To adjust total emissions for sales and exchanges from specified sources, ARB would use source-specific emission factors, as described in Section V.B.1 above.

However, an adjustment may be needed to the manner in which emissions are attributed to certain sales from owned or partially-owned power plants, to address concerns regarding contract shuffling, as discussed in Section V.A. We recommend that ARB require that retail providers explain why sales from owned or partially-owned power plants were undertaken.[19] We recommend that, if the power could not be delivered to the retail provider or the retail provider did not need the power during the hours in which it was sold for reasons such as because it had surplus power from its owned power plants and the specified plant was the marginal plant during the hours in which the power was sold, or if the power was from a California-eligible renewable plant with WREGIS certificates transferred to the buyer along with the power, ARB attribute emissions to the power sold based on the emission factor of the power plant. Otherwise, ARB should use the average emission factor of the retail provider's sources that are available for unspecified sales, as described in Section V.D.2. This recommendation would apply only to the portion of sales in excess of ten percent of the retail provider's proportional ownership-based share of the plant's total net generation.

For sales from all other specified sources, i.e., purchases from power plants that are not owned or partially-owned by the retail provider, we recommend that ARB attribute emissions to the sold power based on the emission attributes of the specified power plant.

### 2. Sales from Unspecified Sources

The Joint Staff report proposes what it calls an "adjusted all-in" methodology for the attribution of GHG emissions to a retail provider's sales from unspecified sources. The Staff method would remove sources reported as serving the retail provider's own native load from its resource mix and then would determine an average GHG emission factor for generation from the remaining owned assets and purchases. The retail provider's sales from unspecified sources would be assigned this average GHG emission factor. The Joint Staff suggest that retail providers be allowed to request that a more disaggregated calculation be performed if they believe that this averaging method

[19] As explained in Section V.A.3, contractual arrangements in which the purchasing party has a contractual entitlement to a specified percentage of the output of a power plant would be treated, for purposes of GHG accounting, as an ownership interest in the power plant.

does not reflect accurately the nature of their transactions. No parties commented on the Joint Staff's proposal to account for GHG emissions associated with sales from unspecified sources using the "adjusted all-in" method.

With some modifications, we adopt Staff's proposal to use the "adjusted all-in" method to calculate GHG emissions associated with retail providers' sales from unspecified sources. First, in addition to sources reported as serving native load, power that the retail provider sold or delivered pursuant to an exchange agreement from specified sources should be removed from the retail provider's resource mix before an average emission factor is calculated for power available for unspecified sales. Additionally, we limit and clarify the sources that a retail provider may claim as serving native load.

### 3. Exports

As described above, the retail providers' GHG emissions responsibilities are adjusted for sales to other entities to meet California load. Sales of power to entities outside the state constitute exports, and emissions responsibilities for power generated in California and exported should be attributed to the selling party, in this case the retail provider.

Some parties argue that they should not be required to report electricity exported from California. SMUD argues that ARB should not consider the emissions associated with exports. It focuses on the language in Section 38530(b)(2), which provides that the GHG regulations shall account for GHG emissions from all electricity consumed in the state whether generated in the state or imported. However, this argument ignores Section 38505(m), which defines "statewide greenhouse gas emissions" as "the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California . . . whether the electricity is generated in state or imported" (emphasis added). One purpose of the language beginning with the word "including" is to ensure that California's GHG regulatory scheme accounts for GHG emissions associated with electricity imported into California for consumption here. However, the part of the definition preceding the word "including" requires the regulatory scheme to encompass all greenhouse gases that are emitted in California. There is nothing in Section 38530(b)(2) that would exclude any in-state emissions or overrule the requirement of Section 38505(m). Accordingly, it is proper for the reporting scheme to include electricity that is generated within the state, whether it is consumed in California or exported out of California.

SMUD contends that the recommended adjustment that would subtract energy sold to counterparties within California from total emissions, but not energy sold to counterparties outside of California. SMUD states that this difference would be an incentive to sell energy to in-state entities and may create an impediment to wholesale sales to out-of-state entities potentially in violation of the dormant Commerce Clause and/or the Federal Power Act. Under a load-based (i.e., a retail provider-based) reporting system, emissions generated within California by retail providers should be accounted for by one retail provider or another. Where such power is sold for consumption in California, the associated emissions can be subtracted from the emissions of the retail provider that generated the power. On the other hand, where power is exported out of the state, it would not be reported by another retail provider, and therefore the associated emissions should not be subtracted from the gross emissions of the retail provider that generated the power. This is not a matter of discriminating against sales to non-California counterparties. Rather, it is an accounting method to help ensure that all California emissions are reported by a retail provider, whether the power is sold in-state or out-of-state. Because there is no discrimination against sales to other states, there is no violation of the Commerce Clause.[20]

SMUD and other parties stress a concern with possible compliance obligations for exports. These parties argue that holding them accountable for emissions related to exports would put a heavier burden on the electricity sector than on any other sector. They contend that contributing emissions associated with exports to California would be contrary to the concept of integrating GHG emission tracking among the states.

While we are aware of the parties' concerns regarding potential double counting of GHG emissions associated with exports if regional GHG regulations develop, AB 32 requirements encompass exports of power generated in California. As a result, we recommend that ARB collect information regarding exports and verify emissions associated with those exports, as detailed in Attachment A. We will address later in this proceeding the manner in which GHG emissions associated with exports should be treated for purposes of AB 32 compliance.

### E. Reporting Requirements for Marketers

Section 3 of the reporting Protocol in Attachment A contains recommended reporting requirements for marketers that import electricity into California or export electricity from California to other states. Data regarding marketers' imports that are used to meet California load would be needed if a first-seller regulatory approach is adopted. Data regarding marketers’ exports would be needed under a load-based approach. We recommend that ARB attribute emissions to marketers' imports used to meet California load and exports in a manner similar to the way in which emissions would be attributed to retail providers, as detailed in Section 3 of Attachment A. We also recommend that marketers be required to report imports into California that terminate in a location outside of California, i.e., that are wheeled through California.

While AB 32 would not regulate emissions associated with power wheeled through California, information regarding the quantity of wheeled electricity would facilitate cross-checking and the derivation of control totals, if the deliverer/first-seller approach is chosen for the electricity sector. If the deliverer/first-seller approach is not chosen, the additional reported information may still be helpful to ARB.

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[20] SMUD does not explain why, in its view, this portion of the reporting protocol might violate the Federal Power Act.

## VI. Recommended Reporting Protocol

### A. What Will Be Reported

In the Joint Staff's proposal, California retail providers would be required to report total GHG emissions from all power used to serve their load in California. That proposal would require that retail providers submit the total quantity of power generated and purchased separately for specified and unspecified sources, emission factors for specified sources, and wholesale sales. However, as described above in Section III, ARB intends to establish emission factors for all specified and unspecified sources. ARB will also determine the total GHG responsibility for each retail provider. As a result, the reporting and verification protocol in Attachment A, which we recommend to ARB, reflects ARB's planned process.

We recommend that ARB require retail providers to report the source of all power used to serve load in California. For specified sources, retail providers would identify the amount of power received and a unique ARB plant identification code. For partially-owned power plants, the percentage ownership share is required. For unspecified sources, retail providers would report the amount of power received and the region that is the source of the power. Retail providers would also report wholesale sales by counterparty and by destination region (California, Northwest, and Southwest). Wholesale sales are also to be differentiated between sales from owned or partially owned power plants, other specified sources, and unspecified sales from the retail provider's pool of generated and purchased power.

As several parties suggest, we recommend that ARB adopt reporting requirements for 2008 that would facilitate consideration by ARB and the Commissions of the deliverer/first-seller type of GHG regulation. We recommend additional reporting requirements, which would direct marketers that either import power into or export power from California to report all such sales by counterparty, disaggregated by region as appropriate. Marketers would also be required to report any power wheeled through the state of California. Additional details regarding the reporting requirements for retail providers and marketers are contained in Attachment A.

### B. Submission Process

#### 1. State Agency Responsibilities for Receiving and Maintaining Data

The Joint Staff proposes that ARB be the primary recipient of all GHG emission reports and that both Commissions receive simultaneous copies of all reports filed with ARB. At this time, we do not see a need for the two Commissions to routinely receive the GHG emission reports. Each Commission may develop data-sharing agreements to ARB. We may also request that reporting entities provide their GHG reports directly if the need arises. If needed, the Commissions will assist ARB in the validation of data submitted in the GHG reports.

### 2. Frequency of Reporting

The Joint Staff proposes that retail providers submit annual GHG reports. Most parties support this proposal. DRA wants quarterly reporting as a means to increase transparency. PG&E recommends that the frequency of reporting be consistent with the nature of the market and recommends that the appropriate frequency be determined after the market has been designed. We agree with Staff's suggestion and recommend that ARB require that retail providers and marketers submit annual reports.

### 3. Verification

Verification is vital to any credible tracking system. ARB proposes to use third-party certification for all reporting under AB 32, and is developing a training and certification program for third party auditors.

While the Joint Staff considers the development of verification rules to be within the ARB's responsibilities, some parties want the Commissions to address verification in more detail. Several parties note that verification would be very difficult for out-of-state operations. Others are concerned about the burden that a verification system might place on retail providers. ED and DRA stress the importance of a strong compliance mechanism in an effective reporting and tracking system.

We agree that verification is a critical component to any mandatory GHG reporting mechanism. ARB is developing a verification process including requirements for third-party certifiers. We believe that ARB is in the best position to develop appropriate verification requirements, and we direct our Staff to work with ARB to address any unique verification requirements for the electricity sector.

### 4. Reporting Template

The Joint Staff proposal includes a reporting template. Several parties recommend clarifications and minor corrections to the template. The Alliance for Retail Markets (AREM) wants a streamlined reporting template for non-asset-owning retail providers.

As we have noted, the Joint Staff's proposal assumes that retail providers would report emission factors and total GHG emission responsibilities. With ARB's plan to develop emission factors itself, we modify the reporting template proposed by the Joint Staff to reflect ARB's planned reporting system. As a result, some of the recommended clarifications and minor corrections proposed by parties are moot.

The reporting requirements that we recommend to ARB are contained in Attachment A, which also contains the template of a sample reporting form that parties could use, subject to any modifications in the reporting requirements that ARB may adopt.

## C. Reducing Reporting Burden

Some of the smaller retail providers believe that the Joint Staff reporting proposal should be modified to reduce the burden and costs on smaller retail providers of reporting GHG emissions. AREM and several POUs desire a web-based reporting system. Some of the smaller retail providers recommend that the Energy Commission work with ARB to reduce duplicative reporting of facility generation. CMUA encourages the Energy Commission, the Public Utilities Commission, and ARB to work toward a single, unified set of reporting requirements.

In modifying the reporting protocol to be consistent with ARB's planned reporting process, we have responded to parties' request for a streamlined reporting protocol that reduces the burden on reporting entities.

### D. Review of Adopted Protocols

Staff recommends that reporting protocols implemented in 2008 be reviewed no later than 2011 so that they can be refined for the first compliance year in 2012.

We agree with Staff that a comprehensive review of the reporting protocol should be conducted prior to the first compliance year in 2012. The review should occur early enough to allow time to implement any revisions in 2011, so that parties may accommodate any revisions prior to the first year of compliance. We recommend that ARB undertake a review early enough to ensure that any revisions will be effective during the 2011 reporting year.

### E. Reporting and Tracking under Deliverer/First-Seller Regulation

Many parties submit that the Joint Staff reporting proposal would need to be modified if a deliverer/first-seller structure is adopted. Some of these parties propose detailed modifications to the Joint Staff proposal to provide the reporting needed under a deliverer/first-seller structure. Most of the proposed changes would require that the first entity that sells power into California track and report the emissions associated with such sales.

We do not address the merits of the deliverer/first-seller approach today, but we recommend that ARB include requirements that marketers report any sales where the marketer is the first party to deliver power into California. This, combined with ARB's intention to require most generators to report source emissions directly to ARB, would provide much, if not all, of the additional information regarding GHG emissions that would be needed if the deliverer/first-seller approach is adopted. It may also reduce retail providers' uncertainty regarding the sources of power bought from marketers. Because the deliverer/first seller approach still requires development, additional reporting changes may be necessary if the deliverer/first-seller approach is adopted.

### F. Confidentiality

AREM requests that the reporting protocol include provisions to maintain the confidentiality of market-sensitive information and to avoid disclosure of detailed transaction data. AREM recommends that the reporting protocol include the "window of confidentiality concept" adopted by the Public Utilities Commission in D.06-06-066.

While we agree with AREM that the early release of market-sensitive information could adversely affect retail providers, we do not make recommendations to ARB regarding the extent to which the data reported to ARB should be treated confidentially. AREM should address its concerns about the release of market-sensitive information in the ARB process that is currently developing confidentiality requirements. In adopting final reporting regulations, ARB will determine what, if any, information will be treated confidentially.

## VII. The Need for Regional Reporting and Tracking

Staff suggests that a comprehensive generation information system could be developed for some or all of the WECC region, as will be covered by the Western Climate Initiative. A regional system would require that all (or most) states and provinces require the plants located in their areas to participate in the tracking system.

The Joint Staff report describes that a growing number of states either allow or require retail providers to designate the generation that serves their native load. Washington and Oregon have a tracking system in place, and several states are adding renewable portfolio standards, which mandate that renewable energy meet a designated portion of native load. The Joint Staff report recognizes that resources used to serve native load in another state should not be counted as sold to California retail providers. Staff proposes a pilot project with Oregon and Washington to help identify resources claimed by sellers to avoid double counting.

Adoption of GHG regulations in additional Western states would increase the importance of a regional reporting and tracking system. One particularly important development is the Governors' Memorandum of Understanding (MOU) to establish a regional GHG program for the Western states that are signatories. To date, the Western Climate Initiative MOU has been signed by the governors of six Western states (California, Washington, Oregon, Arizona, New Mexico, and Utah) and the premiers of British Columbia and Manitoba. Several federal climate change bills also have been proposed in Congress.

Many of the commenting parties urge the Commissions to move forward rapidly with the development of a regional reporting and tracking system. Some parties suggest that California take leadership, either working through the Western Governors Association or starting with the states that signed the MOU. The parties assert that a regional reporting and tracking system is the only way to produce a completely accurate "source-to-sink" accounting of GHG emissions attributed to electricity that serves California's retail load.

A few parties recommend that the Commissions not develop an interim reporting and tracking system, but instead wait until a regional tracking system is implemented. Other parties accept that an interim reporting system is needed in California, but want a regional solution to be in place prior to 2012, the first year that AB 32 GHG emission reduction requirements will be in force. Several parties suggest that concerns about contract shuffling and leakage can only be addressed by having a regional reporting and tracking system.

We support the call for a regional reporting and tracking system made by several parties in this proceeding. A regional solution to reporting and tracking would greatly increase the accuracy of GHG reporting in California. We direct our Staff to support the

California Environmental Protection Agency and ARB to lead a regional development effort through the Western Climate Initiative.

While we support parties' recommendation that a regional solution be in place before January 1, 2012, AB 32 requires that ARB adopt reporting and verification regulations on or before January 1, 2008, and our recommendations support that statutory mandate. The reporting protocol we recommend would aid ARB and the reporting entities during the interim period until a regional reporting and tracking system can be developed and implemented. We recommend that ARB continue to refine our recommendations. Our recommended reporting protocol could be utilized for determining compliance, if a regional solution is not in place by January 1, 2012.

## VIII. Comments on Proposed Decision

The proposed decision of President Michael R. Peevey on this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and Rule 14.6(c)(9) of the Public Utilities Commission Rules of Practice and Procedure, with a reduction in the 30-day period for public review and comment.

Parties filed comments by August 24, 2007 and reply comments by August 30, 2007. Public necessity required that the comment period be reduced so that the Public Utilities Commission and the Energy Commission can provide recommendations to ARB by mid-September, 2007 and so that ARB may consider these recommendations as it prepares its draft regulations for publication in mid-October. AB 32 requires that ARB adopt reporting regulations on or before January 1, 2008. We find that the need for timely recommendations to ARB, when balanced against the need for comments, warrants the reduced comment period. We note further that, through this decision and comparable action anticipated by the Energy Commission, the two Commissions propose rules to ARB, which ARB may refine further if it is persuaded through its public process that changes are warranted.

We have made corrections and clarifications in the proposed decision in response to comments, as well as substantive changes on selected issues, as we describe in today's decision.

## IX. Assignment of Proceeding

President Michael R. Peevey is the Assigned Commissioner in this proceeding, and Charlotte F. TerKeurst and Jonathan Lakritz are the assigned Administrative Law Judges in Phase 2 of this proceeding.

## X. Findings of Fact

1. Some purchases of electricity cannot be traced to a specific generation source.
2. To attribute emissions to California retail providers for purchases of electricity that cannot be traced to a specific generation source, ARB will need to establish emission factors.
3. A uniform regional default emission factor for purchases from unspecified sources would minimize the potential gaming and arbitrage among regions.

4. A provision whereby ARB may certify supplier-specific emission factors and the setting of a conservative regional default emission factor would help accomplish the goals of AB 32 by encouraging market participants to obtain their power from specified sources.

5. A regional tracking system for the electricity sector is needed for an expandable GHG regulatory system because so much power is bought and sold across state lines in the highly interconnected Western electricity market.

6. The Protocol in Attachment A is a reasonable rule for reporting and tracking GHG emissions from the electricity sector.

7. In some situations, to ensure that only real GHG reductions are calculated for power transactions reported by California retail providers, ARB may need to attribute emissions to purchases or sales of power by California retail providers that are different than the GHG emissions that occur from the source specified in the contract.

8. The public interest in the Public Utilities Commission adopting a decision on reporting and verification of GHG emissions in the electricity sector before expiration of the 30-day review and comment period clearly outweighs the public interest in having the full 30-day period for review and comment.

## Conclusions of Law

1. Under AB 32, ARB has the authority to adopt conditions that would prevent the attribution to retail providers of GHG emission reductions that are not real.

2. AB 32 governs statewide GHG emissions, including electricity consumed in California (including imports) and in-state generation that is exported out of California.

## INTERIM ORDER

Therefore, **IT IS ORDERED** that the California Public Utilities Commission recommends that the California Air Resources Board adopt the Proposed Electricity Sector Greenhouse Gas Reporting and Verification Protocol contained in Attachment A to this order.

This order is effective today.

Dated _________________________, at San Francisco, California.

Attachment 1 (Rev 1) Peevey R0604009

**ATTACHMENT A**

# Proposed Electricity Sector
# Greenhouse Gas Reporting and Verification Protocol

## 1. Definitions and Covered Entities

### **1.1** Definitions

#### **1.1.1** Asset-controlling Entity

"Asset-controlling entities" are entities that operate power plants or serve as exclusive marketers for certain power plants even though they do not own them.

#### **1.1.2** Asset-owning Entity

An "asset-owning entity" is an entity that owns power plants. Asset-owning entities may include, but are not limited to, independent power producers, qualifying facilities (QFs), investor-owned utilities (IOUs), publicly owned utilities (POUs), state agencies, federal agencies, and community choice aggregators (CCAs).

#### **1.1.3** Emission Factor

An "emission factor" is a ratio that reflects the level of emissions of a specified pollutant per unit of specified activity, e.g., pounds of carbon dioxide ($CO_2$) equivalent emissions emitted per megawatt-hour (MWh) of electricity produced.

#### **1.1.4** Exchange Agreement

An "exchange agreement" is an agreement between electricity market participants that provides for an exchange of energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

Generating Unit

**1.1.5** Generating Unit

A "generating unit" or "unit" is comprised of one or more physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

**1.1.6** Marketer

A "marketer" is a Purchasing/Selling entity that is not a retail provider and that is listed as the Purchasing/Selling Entity at the first point of delivery in California for power imported into California or the last point of receipt for power exported from California.

**1.1.7** Multi-jurisdictional Utilities

"Multi-jurisdictional utilities" are distribution utilities that provide electricity to end users in California and in one or more other states.

**1.1.8** Null Power

"Null power" is any electricity produced by a renewable electricity facility from which a Western Renewable Energy Generation Information System (WREGIS) certificate has been unbundled and sold separately.

**1.1.9** Pacific Northwest

The "Pacific Northwest" or "Northwest" region includes Washington, Oregon, Idaho, Montana, and British Columbia.

**1.1.10** Point of Delivery

A "point of delivery" is a point on an electric system where a power supplier delivers electricity to the receiver 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.

**1.1.11** Point of Receipt

A "point of receipt" is a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.

**1.1.12** Power Contract

A "power contract" is an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

**1.1.13** Power Plant

A "power plant" or "plant" is a facility for the generation of electricity which may be comprised of one generating unit, or more than one generating unit if (a) the units are at the same location, and (b) each unit utilizes the same resource (fuel). For purposes of this Protocol, the terms "unit" and "plant" are used interchangeably, but the reporting entity shall report the quantities of electricity generated, sold, or purchased for each individual unit wholly-owned, partially-owned, or identified in power contracts as applicable.

**1.1.14** Purchasing/Selling Entity

A "Purchasing/Selling Entity" is an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

**1.1.15** Qualifying Facility

A "Qualifying Facility" is a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.

**1.1.16** Retail Provider

"Retail provider" means an entity that provides electricity to end users in California. Thus, "retail provider" includes electrical corporations (including IOUs, multi-jurisdictional utilities, and electric cooperatives), POUs (including municipalities, municipal utility districts, public utility districts, irrigation districts, and joint power authorities), electric service providers (ESPs), CCAs, and the Western Area Power Administration (WAPA).

**1.1.17** Sink

A "sink" is the final point of delivery for an electricity transaction: the actual load.

**1.1.18** Southwest

The Southwest region includes Arizona, Nevada, Utah, Colorado, and western New Mexico.

**1.1.19** Specified Sources

"Specified sources" are generating units or power plants whose electrical generation can be tracked due to full or partial ownership by the reporting entity, or due to their identification in a power contract with the generator or marketer selling the power. Specified sources may also include federally-managed hydroelectric facilities, to the extent their power is specifically allocated to a reporting entity.

**1.1.20** Substitute Energy

"Substitute energy" refers to energy delivered under a plant-specific power contract that was not produced by the plant specified in the contract.

**1.1.21** Unspecified Sources

"Unspecified sources" refers to the origin of purchases of electricity that cannot be tracked to a particular power plant. Many purchases from entities that own fleets of power plants such as independent power producers, utilities, and federal power agencies, and many purchases from marketers and brokers are purchases from unspecified sources. All purchases from pooled power markets are from unspecified sources.

### 1.2 Reporting Entities

This Electricity Sector Greenhouse Gas Reporting and Verification Protocol (Protocol) applies to every retail provider in California. Since WAPA sells a small amount of power to end users in California, it is a retail provider and is requested to report under this Protocol. The California Department of Water Resources (DWR) and any other state agencies that generate or procure power for their own use from any entity that is not a retail provider are required to report, using the reporting requirements for retail providers in this Protocol, the power that they generate or procure to serve their own loads.

Additionally, the Protocol applies to all marketers that import power into or export power from California, meaning any marketer delivering electricity to the first point of delivery in California or, for exported power, delivering electricity to the first point of delivery outside California.

The reporting requirements for retail providers are contained in Section 2 of this Protocol, and the reporting requirements for marketers are contained in Section 3 of this Protocol. Section 4 describes the process by which entities may propose supplier-specific emission factors for sales or purchases from unspecified sources.

In addition to any requirements imposed by this Protocol, power plants are required to report emissions using the source-based protocol (California Code of Regulations, Title 17, Subchapter 10, Article 1, sections 95100 to 95132).

## 2. Retail Provider Reporting Protocol

For each calendar year, retail providers shall comply with the reporting requirements in Subsections 2.1, 2.3, 2.5, 2.8, 2.10, and 2.12. The other subsections in Section 2 describe how the California Air Resources Board (ARB) attributes GHG emissions to each retail provider.

Report all quantities of electricity generated, purchased, or sold in MWh, as measured at the busbar or, if busbar data is not available, at the first point of receipt for which the reporting entity has information.

Report quantities of electricity received under exchange agreements as purchases, and quantities of electricity delivered under exchange agreements as sales.

Report substitute energy received from specified sources under the appropriate category in Section 2.3, and report substitute energy received from unspecified sources under the appropriate category in Section 2.5.

If a reporting entity has a contract with a specified source that provides the reporting entity with a contractual entitlement to a specified percentage of the plant's output, the reporting entity shall report power it purchases and sells from such plants as being from a partially-owned plant pursuant to Sections 2.1 and 2.8.1.

### 2.1 Net Generation from Wholly-owned and Partially-owned Power Plants

For each wholly-owned power plant, provide the plant name and ARB plant identification code. For each partially-owned power plant, provide the plant name and ARB plant identification code, the percentage ownership share of the reporting entity, and the quantity of net generation received by the reporting entity.

For each power plant, indicate whether the plant is identified for GHG reporting purposes as used exclusively to serve native load. One of the following three conditions must be met in order for a reporting entity to choose to report a plant as exclusively serving native load:

1. The plant is a California-eligible renewable resource and, prior to the reporting date, the reporting entity has retired the WREGIS certificates associated with the power received from the facility during the reporting year.

2. The plant is a hydro generation facility whose output the reporting entity takes whenever it is available.

3. The plant is a baseload plant running at an annualized capacity factor of 60 percent or greater. If a plant is reported as serving native load on this basis, all wholly-owned or partially-owned plants running at the same or greater annualized capacity factor shall also be reported as serving native load.

For each plant reported as serving native load, the reporting entity shall indicate which of the three conditions is met.

### 2.2 Calculation of Emissions from Wholly-owned and Partially-owned Power Plants

For wholly-owned and partially-owned power plants that report under ARB's source-based reporting system, ARB retrieves the emissions for all GHGs and the generation data transmitted to ARB under the source-based reporting system, and calculates an emission factor on that basis.

For power plants not reporting under ARB's source-based reporting system, ARB calculates emission factors using data from finalized reports under 40 CFR Part 75 or plant-level fuel consumption data from the Energy Information Administration if Part 75 data are not available.

ARB attributes emissions to the reporting entity based on its fractional ownership share (i.e., the product of the plant's net generation, the percentage ownership share, and the plant's emission factors), which may then be adjusted to reflect sales pursuant to Section 2.9 or Section 2.11.

## 2.3 Purchases from Specified Sources

For power purchased from each specified source, provide the plant name, ARB plant identification code, and the quantity of electricity purchased.
For each purchase from a renewable resource, indicate the quantity of the purchase that was null power.

For purchases from each nuclear plant, and each hydro plant greater than 30 megawatts (MW) nameplate capacity that is not a California-eligible renewable resource, indicate the quantity of the purchase that was made through a power contract that was in effect prior to January 1, 2008 and either is still in effect or has been renewed without interruption.
For each out-of-state power plant, indicate the quantity of the purchase that the reporting entity delivered to the first point of delivery in California.

For each power plant, indicate whether purchases from the plant are identified for GHG reporting purposes as used exclusively to serve native load. One of the following three conditions must be met in order for a reporting entity to choose to report purchases from a plant as exclusively serving native load:

1. The plant is a California-eligible renewable resource and, prior to the reporting date, the reporting entity has retired the WREGIS certificates associated with the power received from the facility during the reporting year.

2. The plant is a hydro generation facility whose output the reporting entity takes whenever it is available.

3. The plant is a baseload plant running at an annualized capacity factor of 60 percent or greater. If purchases from a plant are reported as serving native load on this basis, all purchases from specified sources running at the same or greater annualized capacity factor shall also be reported as serving native load.

4. The plant is a Qualifying Facility whose generation the reporting entity purchases under a power contract.

For each plant that the reporting entity lists as exclusively serving native load, the reporting entity shall indicate which of the four conditions are met.

## 2.4 Calculation of Emissions for Purchases from Specified Sources

2.4.1 For each purchase from a nuclear unit, or hydro plant of greater than 30 MW nameplate capacity that is not a California-eligible renewable resource, that was not made through a power contract that was in effect prior to January 1, 2008 and either is still in effect or has been renewed without interruption, ARB attributes emissions based on the net generation purchased and the default emission factor for the region in which the nuclear or hydro plant is located.

2.4.2 For all purchases from a specified source that reports under ARB's source-based reporting program, except purchases addressed in paragraph 2.4.1, ARB attributes emissions from these plants based on the quantity of net generation purchased and the plant's emission factors.

2.4.3 For all purchases from a specified source that does not report under ARB's source-based reporting program, except purchases addressed in paragraph 2.4.1, ARB calculates emission factors using data from finalized reports under 40 CFR Part 75 or plant-level fuel consumption data from the Energy Information Administration if Part 75 data are not available, and attributes emissions based on the calculated emission factors and net generation purchased.

2.4.4 Emissions attributed to the reporting entity for purchases from specified sources may be adjusted to reflect sales pursuant to Section 2.9 or Section 2.11.

**2.5 Purchases from Unspecified Sources**

Report all purchases of power from unspecified sources, other than those from the pooled California Independent System Operator (CAISO) real-time market and pooled Integrated Forward Market. Aggregate the purchases by counterparty but, for each counterparty, separately report the total quantities of electricity purchased from each of the three resource regions (Northwest, Southwest, and California). If there are any electricity purchases for which the region of origin cannot be determined, report these quantities as from "unknown region." Receipt of power attributed to the Northwest or Southwest region must be verifiable via North American Electric Reliability Corporation (NERC) Etags.

For each counterparty and region, indicate the quantity of purchases that the reporting entity delivered to the first point of delivery in California.

Report separately the quantity of purchases from the CAISO pooled real-time market and the CAISO pooled Integrated Forward Market, i.e., purchases not under contracts with specified counterparties.

**2.6 Calculation of Emissions for Purchases from Unspecified Sources**

For counterparties for which ARB has certified supplier-based emission factors (developed pursuant to Section 4), ARB multiplies the quantity of purchases from each supplier by the certified emission factors.

For other purchases, ARB sums the quantities of purchases for each region and CAISO market and multiplies the totals by the corresponding default emission factor.

ARB attributes emissions to purchases reported as originating from an unknown region using the highest of the three regional (California, Northwest, or Southwest) default emission factors.

### 2.7 Total $CO_2e$ Emissions from Wholly-owned and Partially-owned Plants and Purchases

ARB sums the total metric tons of emissions from wholly- and partially-owned power plants, purchases from specified sources, and purchases from unspecified sources as described in the above sections. ARB then converts the GHG emissions to $CO_2$ equivalents and calculates the total. The total emissions attributed to the reporting entity may be adjusted to reflect sales reported pursuant to Section 2.8 or Section 2.10.

### 2.8 Sales from Specified Sources

**2.8.1** Sales from Wholly-Owned and Partially-Owned Power Plants

For each power plant wholly-owned or partially-owned by the reporting entity, and for each power plant from which specified sales were made, identify the plant name and ARB plant identification code, and report the quantity of power sold (by or on behalf of the reporting entity) separately for each counterparty and destination region (California, Northwest, Southwest, or unknown).

In reporting sales from wholly-owned or partially-owned power plants to the California region, the reporting entity shall include only sales from power plants to other California retail providers, to the CAISO pooled markets, and to other parties where the power can be demonstrated to sink in California.

If the reporting entity delivers power to a point of delivery within California for which it cannot verify the destination region, the reporting entity shall report that sale as being to an unknown region.

For each power plant wholly-owned or partially owned by the reporting entity, if the fractional ownership share-based amount of plant output is larger than the quantity of power received, as reported pursuant to Section 2.1, plus the sum of sales from that power plant by or on behalf of the reporting entity, the reporting entity shall report any remainder as a sale of power from the power plant to an unknown region.

For each sale from a wholly-owned or partially-owned power plant, the reporting entity shall indicate whether the power was sold for either of the following reasons, with supporting documentation:

1. The power could not be delivered to the reporting entity during the hours in which it was sold.

2. The reporting entity did not need the power during the hours in which it was sold, for reasons such as the power was sold during hours in which the specified plant was plausibly the marginal plant.

For each wholly-owned or partially-owned power plant that is a California-eligible renewable plant, the reporting entity shall indicate separately the quantity of sales for which the WREGIS certificates were transferred to the buyer along with the power.

**2.8.2** Sales of Electricity Purchased from Specified Sources

For specified sales of electricity purchased from other specified sources not reported in Section 2.8.1, for each plant provide the plant name and ARB plant identification code and the quantity of electricity sold separately for each counterparty and destination region (California, Northwest, Southwest, or unknown).

In reporting sales to the California region, the reporting entity shall include only sales to other California retail providers, to the CAISO pooled markets, and to other parties where the power can be demonstrated to sink in California.

If the reporting entity delivers sold power to a point of delivery within California for which it cannot verify the destination region, the reporting entity shall report that sale as being to an unknown region.

For each sale from a specified source that is a California-eligible renewable plant, the reporting entity shall indicate the quantity of sales for which the WREGIS certificates were transferred to the buyer along with the power.

**2.9 Adjustments to Total Emissions for Sales from Specified Sources**

For purposes of GHG attribution under Section 2.9, sales reported as sales to an unknown region shall be deemed sales to a party outside of California.

**2.9.1** Adjustments to Total Emissions for Sales from Specified Sources to Parties within California

ARB attributes emissions by multiplying sales from each specified source to parties within California by the relevant emission factor. ARB then deducts the total emissions attributed to sales from specified sources to parties within California from the totals described in Section 2.7.

To adjust total emissions for sales from specified sources, ARB uses the emission rates of each plant either reported under the source-based reporting system or as calculated by ARB (see Section 2.2).

**2.9.2** Adjustments to Total Emissions for Sales from Specified Sources to Parties Located Outside of California

*2.9.2.1 Adjustments to Total Emissions for Sales from Specified Sources Located in California*

Specified sales from specified sources located in California to parties with a point of delivery outside of California are exports. Responsibility for the emissions resides with the selling entity and no adjustments are needed to total emissions described in Section 2.7.

*2.9.2.2 Adjustments to Total Emissions for Sales from Specified Sources Located Outside of California*

ARB adjusts the total emissions described in Section 2.7 for emissions attributed to sales to parties with a point of delivery outside California from purchases of specified sources located outside of California by multiplying emission rate for each power plant underlying the sale of the specified source by the quantity of power sold. ARB then deducts the total emissions attributed to sales from purchases of electricity from specified sources to parties outside California from the totals described in Section 2.7.

ARB uses the emission rates of each plant either reported under ARB's source-based reporting system or as calculated by ARB (see Section 2.2).

For sales from wholly-owned or partially-owned power plants located outside of California, including plants under contract for a fixed percentage of output, to parties located outside of California, ARB adjusts the total emissions described in Section 2.7 as follows.

If the reported specified sales and deliveries from a wholly-owned or partially-owned power plant amount to less than ten percent of the reporting entity's fractional ownership share of power from the plant, and if the sale does not meet one or both of the conditions specified in Section 2.8, ARB attributes emissions by multiplying each plant's sales to parties outside California by the emission rates of each plant either reported under the source-based reporting system or as calculated by ARB (see Section 2.2). ARB then deducts the total emissions attributed to sales from wholly-owned or partially-owned power plants located outside California to parties with a point of delivery outside California from the totals described in Section 2.7.

For sales from wholly-owned or partially-owned power plants located outside of California to parties with a point of delivery outside California, if the reported specified sales from a wholly-owned or partially-owned power plant amount to more than ten percent of the reporting entity's fractional ownership share of power from the plant and if the sale does not meet one or both of the conditions specified in Section 2.8, ARB attributes emissions as follows:

1. Multiply the portion of the sales equal to ten percent of the reporting entity's fractional ownership share of power from the plant using the emission rate of each plant either

reported under the source-based reporting system or as calculated by ARB (see Section 2.2).

2. Multiply the portion of the sales exceeding ten percent of the reporting entity's fractional ownership share of power from the plant using the average emission factor of power available for sales from unspecified sources (calculated as described in Section 2.11).

ARB then deducts the total emissions attributed to sales from wholly-owned or partially-owned plants from the totals described in Section 2.7.

**2.10 Sales from Unspecified Sources**

Report aggregated sales from unspecified sources, reported separately for each counterparty and each destination region (California, Northwest, Southwest, or unknown). Report quantities as measured at the first point of receipt for which the reporting entity has information.

In reporting sales from unspecified sources to the California region, the reporting entity shall include only sales from unspecified sources to other California retail providers, to the pooled CAISO markets, and to other parties where the power can be demonstrated to sink in California. If the reporting entity delivers power to a point of delivery within California for which it cannot verify the destination region, the reporting entity shall report that sale as being to an unknown region.

**2.11 Adjustments to Total Emissions for Sales from Unspecified Sources**

ARB adjusts the total emissions described in Section 2.7 for emissions attributed to sales from unspecified sources as reported pursuant to Section 2.10.

For purposes of GHG attribution under Section 2.10, sales reported as sales to an unknown region shall be deemed sales to a party outside California.

To obtain the quantity of power available for sales from unspecified sources, ARB deducts, from the total amount of electricity from owned or partially-owned facilities and purchases, the quantities of power from the following sources:

1. Sources reported as serving native load, as described in Section 2.1 and Section 2.3.

2. Sales from specified sources, as described in Section 2.8.

To obtain the amount of emissions associated with power available for sales from unspecified sources, ARB deducts from the total emissions from wholly-owned and partially-owned facilities and purchases, as described in Section 2.7, all emissions attributed to the sources in the itemized list above.

The average emission factor of power available for sales from unspecified sources is the ratio of the emissions from power available for sales from unspecified sources to the quantity of power available for sales from unspecified sources.

To adjust the total GHG emissions for sales from unspecified sources to parties within California, ARB multiplies the quantity of electricity sold from unspecified sources to parties within California, as reported pursuant to Section 2.10, by the average emission factors available for sales from unspecified sources. These quantities are deducted from the total emissions calculated as described in Section 2.7 and adjusted as described in Section 2.9.

To adjust the total GHG emissions for sales from unspecified sources to parties outside California, ARB multiplies the quantity of electricity sold from unspecified sources to parties outside California, as reported pursuant to Section 2.10, by the average emission factors for sales from unspecified sources, and pro rates by the ratio of the emissions from in-state sources in the pool divided by all emissions in the pool. ARB deducts the emission from unspecified sales to parties outside of California from the total emissions calculated as described in Section 2.7 and adjusted as described in Section 2.9.

### 2.12 Reporting by Multi-jurisdictional Utilities and WAPA

Multi-jurisdictional utilities shall report the information required in Subsections 2.1, 2.3, 2.5, 2.8, and 2.10 for the service territory that includes California end use customers. They shall report California retail sales, and also total retail sales in the service territory that includes California end use customers.

WAPA is requested to report the information identified in Subsections 2.1, 2.3, 2.5, 2.8, and 2.10 for the sources of electricity that are used to serve the WAPA Lower Colarado River service territory . WAPA is also requested to report California retail sales and total retail sales in the WAPA Lower Colarado River service territory.

### 2.13 Calculation of Emissions for Multi-jurisdictional Utilities and WAPA

For each multi-jurisdictional utility and WAPA, ARB determines emissions associated with the utility’s service territory that includes California end use customers and attributes a pro-rata share of those emissions to the reporting entity in California, based on the ratio of California retail sales to total retail sales in that service territory.

### 2.14 Requests for Exemptions

On a case-by-case basis, a reporting entity may request that ARB modify its determination of emissions to be attributed to the reporting entity based on the methodology set forth in Section 2. Such a request for exemption shall document why the reporting entity believes that the methodology in Section 2 does not recognize real reductions in GHG emissions that have been achieved due to the reporting entity’s actions, and shall contain a proposed alternative determination of attributable emissions, with complete supporting documentation.

# 3. Marketer Reporting Protocol

Marketers shall comply with the reporting requirements in Subsections 3.1, 3.3, and 3.4. The other subsections in Section 3 describe how ARB attributes GHG emissions to each marketer.

Report all quantities of electricity generated, purchased, or sold in MWh, as measured at the busbar or, if busbar data is not available, at the first point of receipt or point of delivery for which the reporting entity has information. For purposes of this Protocol, quantities of electricity received under exchange agreements are considered purchases, and quantities of electricity delivered under exchange agreements are considered sales.

## 3.1 Imports

Exclude any transactions reported pursuant to Section 3.3.

Report all imports of electricity from specified sources with a final point of delivery in California that the reporting entity delivered to the first point of delivery in California, reported separately for each power plant supplying the power. Include the plant name and ARB plant identification code for each plant.

Report all imports of electricity from unspecified sources with a final point of delivery in California that the reporting entity delivered to the first point of delivery in California, reported separately for each region of origin (Northwest or Southwest) and, within each region, reported separately for each party supplying the power, including the reporting entity itself where applicable.

## 3.2 Calculation of Emissions from Imports

Emissions are calculated based on the quantities of electricity imported and the corresponding emission factors as described below.

For imports from specified sources that report under ARB's source-based reporting system, ARB retrieves the emissions for all GHGs and the generation data transmitted to ARB under the source-based reporting system, and calculates emission factors on that basis.

For imports from specified sources not reporting under ARB's source-based reporting system, ARB calculates emission factors using data from finalized reports under 40 CFR Part 75 or plant-level fuel consumption data from the Energy Information Administration if Part 75 data are not available.

For imports from unspecified sources for which ARB has certified supplier-based emission factors (developed pursuant to Section 4), ARB uses the certified supplier-based emission factor. For imports from all other unspecified sources, ARB uses the appropriate regional default emission factor.

### 3.3 Wheel-throughs

Report any electricity imported into California that terminates in a location outside of California, as measured at the first California point of delivery. Report these transactions aggregated separately for each counterparty supplying the power, and for each region of origin (Northwest or Southwest), These transactions must be verifiable via NERC Etags.

### 3.4 Exports

Exclude any transaction reported pursuant to Section 3.3.

Report all exports of electricity from specified sources that the reporting entity delivered to the first point of delivery outside California. Report totals separately for each power plant supplying the power. Include the plant name and ARB plant identification code for each plant.

Report all exports of electricity from unspecified sources that the reporting entity delivered to the first point of delivery outside California.

### 3.5 Calculation of Emissions from Exports

Emissions are calculated based on the quantities of electricity exported and the corresponding emission factors as described below.

For exports from specified sources that report under ARB's source-based reporting system, ARB retrieves the emissions for all GHGs and the net generation data transmitted to ARB under the source-based reporting system, and calculates an emission factor on that basis.

For exports from specified sources not reporting under ARB's source-based reporting system, ARB calculates emission factors using data from finalized reports under 40 CFR Part 75 or plant-level fuel consumption data from the Energy Information Administration if Part 75 data are not available.

For exports from unspecified sources for which ARB has certified supplier-based emission factors (developed pursuant to Section 4), ARB uses the certified supplier-based emission factor. For exports from all other unspecified sources, ARB uses the appropriate default emission factor.

## 4. Supplier-based Emission Factors

Asset-owning or controlling entities may request that ARB certify a supplier-specific emission factor for their sales from unspecified sources. An entity making such a request shall document that the power it sells originates from a fleet of plants either under its operational control or for which it serves as exclusive marketer and shall document the derivation of its proposed supplier-specific emission factor.

# 5. Submission Process

## 5.1 Submission of Reports

Retail providers and marketers shall provide annual GHG emission reports, due to ARB as required by ARB reporting deadlines.

## 5.2 Verification

ARB has proposed using third-party certification and is developing a training and certification program for third party auditors.

**(END OF ATTACHMENT A)**

# ATTACHMENT E

## Technical Attachment on Development of Emissions Reporting Requirements for Oil Refineries and Hydrogen Plants

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## TECHNICAL ATTACHMENT: DEVELOPMENT OF EMISSIONS REPORTING REQUIREMENTS FOR OIL REFINERIES AND HYDROGEN PLANTS

*This nonregulatory attachment provides background information and a description of the proposed emission estimation methods for oil refineries and hydrogen plants.*

### Background

The California Global Warming Solutions Act of 2006 (the Act) requires that the Air Resources Board "*ensure rigorous and consistent reporting of (GHG) emissions and provide reporting tools and formats to ensure collection of necessary data…. beginning with the sources or categories that contribute the most to statewide emissions*."

There are currently twenty-one petroleum refineries operating in the State of California and these refineries produce some 60 percent of the fuels consumed in the State. Numerous energy intensive refinery processes transform domestic and imported crude oils into the fuels and chemicals routinely consumed by industry and consumers in California. Greenhouse gas emissions from these 21 refineries are estimated to contribute roughly 7 percent of the total $CO_2$, $CH_4$ and $N_2O$ emissions in the State each year. Thus petroleum refinery operations were identified as major contributors to statewide GHG emissions and are subject to mandatory greenhouse gas reporting requirements under the Act.

The process of developing reporting regulations for the petroleum refinery sector has been a multi-faceted process involving staff at ARB, industry representatives and a host of stakeholders from the public and private sectors. A Refinery Sector Technical Team was established with over 85 individuals expressing an interest in participating in the process. Four well-attended Technical Team meetings were held where ARB personnel lead discussions on GHG reporting methodologies and solicited comments and input from the Technical Team participants. This public process lead to the release of a preliminary draft regulatory document on August 10, 2007. The draft documentation contains greenhouse gas emission reporting methodologies developed by ARB for the refinery, hydrogen production, and oil and gas exploration and production (E&P) sectors. This regulatory development process is discussed in detail in this section of the Staff Report.

The Act also directs the ARB to "*where appropriate and to the maximum extent feasible, incorporate the standards and protocols developed by the California Climate Action Registry."* The Registry's General Reporting Protocol (GRP) has been very helpful in guiding the process. Many of the reporting procedures detailed in the GRP such as the section on Stationary Combustion have relevance to the refinery sector and have thus been incorporated where applicable in the CARB GHG reporting methodology. CCAR has not yet developed GHG reporting protocols to meet the particular needs of refineries, hydrogen plants and the E&P sector. However, in parallel to the ARB regulatory development process, CCAR developed a "Discussion Paper for a Petroleum

Refining Greenhouse Gas Accounting and Reporting Protocol" which provided valuable input as well.

The first step in the development of a GHG reporting methodology was the adoption of a set of principles which inform and guide the process. Several core principals guide the development of an effective greenhouse gas reporting program. As outlined in a World Resources Institute document (The Greenhouse Gas Protocol) and the 2006 IPCC Guidelines, any reporting methodology must be relevant, complete, consistent, transparent, and accurate.

Once these underlying principles were established, the next step taken in developing GHG reporting methodologies was to identify the major sources of GHG emissions within the refinery, hydrogen plant and oil and gas production field sectors. If a reporting methodology is to be relevant and accurate it is essential that the largest emission sources are well characterized and reporting methods designed to be as rigorous as possible. The degree of materiality of all source categories must be a primarily consideration in designing a relevant, complete and accurate data collection and GHG reporting methodology.

**Table A: Greenhouse Gas Sources within the Oil and Gas Industry**

| Category | GHGs | Primary Sources |
|---|---|---|
| Stationary Combustion | $CO_2$<br>$CH_4$<br>$N_2O$ | boilers, heaters, furnaces, IC engines, turbines, incinerators |
| Process Emissions | $CO_2$<br>$CH_4$ | hydrogen plants, catalytic cracking units and catalyst regeneration, sulfur recover units, process vents |
| Fugitive Emissions | $CH_4$<br>$CO_2$ | wastewater treatment, storage tanks, oil/water separators. equipment fugitive emissions |
| Flaring | $CO_2$<br>$CH_4$<br>$N_2O$ | tail gas destruction, start-up shut-down emissions |

A general categorization of greenhouse gas emissions within the petroleum refining sector is shown in Table A. Emission categories are listed in descending order of relative size and importance to overall facility GHG emissions. The first two categories, stationary combustion and process emissions, contribute the majority of the GHG emissions from petroleum refineries and hydrogen plants, accounting for over 90 percent of total emissions. Fugitive emissions and flaring contribute relatively minor amounts (<10 percent) of total GHG emissions.

A second critical step in the development of an accurate and complete GHG reporting protocol is an assessment of existing relevant resources and GHG calculation methodologies. A number of documents provided valuable guidance on more generic

GHG accounting practices common to a variety of industrial sectors. The CCAR GRP was mentioned above. The Department of Energy voluntary reporting guidelines established under section 1605(b) of the 1992 Energy Policy Act (DOE, 2007) is another valuable reference for more general GHG reporting guidance and methods.

Petroleum refining involves many energy intensive GHG generating processes which are sector specific. The 2003 publication from IPIECA (Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions) supplements the best practices developed in the WRI/WBCSD Greenhouse Gas Protocol with petroleum industry guidance. This document provided guidance on issues such as defining reporting boundaries, identifying and evaluating GHG emission sources and general reporting guidelines. Publications of the Canadian Association of Petroleum Producers (e.g. CAPP, 1999, 2003), while focused primarily on the up-stream exploration and production segment of the industry, were also helpful. IPCC documents provided general guidance (Volume 1) and specific direction in the areas of combustion emission calculations (Volume 2 Energy) and fugitive emissions (e.g. Volume 5 Waste) (IPCC, 2006).

For process specific GHG methodologies, the American Petroleum Industries (API) Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (API 2004) was consulted extensively and this document served as the basis for many of the GHG methodologies in the CARB regulation. The API Compendium (hereafter referred to as API) is an extensive 480 page document that covers key industry segments ranging from the exploration and production of oil and natural gas, to refining and product distribution.

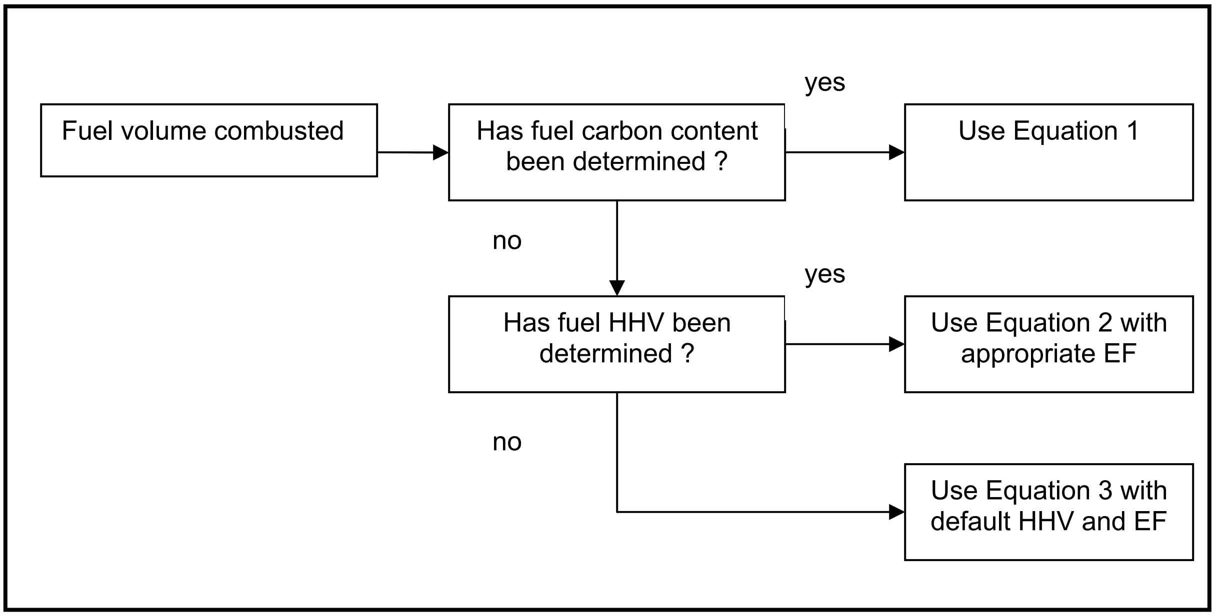
Once staff identified and prioritized the processes responsible for GHG emissions, a second critical consideration was addressed. Accurate GHG accounting requires reliable and accurate data on the chemical composition (specifically carbon content) and heating value (HHV, Btu/fuel unit) of major fuels and feed stocks. High quality activity data is also essential as the rate at which fuels and feed stocks are consumed is a central input of an accurate GHG emission accounting practice. The refinery reporting methodologies are based on the quantity and type of fuel combusted. These fuel specific methods are discussed in detail below.

## 95113. Reporting Requirements for Petroleum Refineries

### (a) Stationary Combustion – $CO_2$ Section 95113(a)(1)

A review of standard stationary combustion $CO_2$ emissions accounting methodologies will help frame the discussion of the fuel specific methodologies which follows. Below we present a decision tree very similar to one provided in API to illustrate possible calculation methods. In a number of cases API presents preferred and alternative approaches or calculation methodologies. For the sake of consistency, staff has provided a single methodology for most calculations. However, we have worked to insure that the regulatory methods are flexible enough to cover the range of operational parameters encountered in the 21 California refineries.

**Figure A: Decision Tree for Stationary Combustion $CO_2$ Emission Calculation Methodologies**




Equation (1)

$$CO_2 = \text{Fuel Volume x Fuel Carbon Content}$$

Equation (2)

$$CO_2 = \text{Fuel Volume x Fuel HHV x Fuel Specific or Default EF}$$

Equation (3)

$$CO_2 = \text{Fuel Volume x Default Fuel HHV x Default Fuel EF}$$

The most reliable and accurate method available for calculating stationary combustion $CO_2$ emissions is the material or mass balance method which is shown in Equation 1. API classifies this method as “preferred” and CCAR (2007 Discussion Paper) and DOE also recognize the material balance approach as one which provides a high level of accuracy.

Here the fuel volume and carbon content are measured by the facility (or fuel supplier) and the product of these two terms determines $CO_2$ emissions. The only implicit assumption in this calculation is that all the carbon contained in the fuel is converted to $CO_2$. An oxidation factor (usually ≤ 1 percent) may be added to this equation to account for the very small fraction of fuel carbon that remains un-oxidized. Fuel carbon content is typically determined using either in-line chromatographic instrumentation or by grab samples which are subsequently analyzed by the refiner or in a third party laboratory. Recognizing that this analysis can be costly and may require the installation of instrumentation, we have examined a second calculation method which requires less sophisticated instrumentation and fewer chemical analyses. This method is shown in Equation 2.

In Equation 2, $CO_2$ emissions are calculated as the product of three variables 1) the fuel volume, 2) the fuel high heating value (HHV), and 3) a fuel specific $CO_2$ emission factor (EF). In this case, the fuel specific EF must be measured, either by the reporter or fuel supplier. The frequency of the HHV measurement will also be determined by the extent of fuel variability. The third factor, the fuel specific $CO_2$ emission factor, may be determined by the reporter, or in certain circumstances, it may be appropriate to use a default emission factor supplied by ARB. However, in some circumstances, the use of a default emissions factor may introduce unacceptably large error. It is very important that the emission factor be accurate if this calculation is to produce accurate emissions estimations.

Finally, the approach outlined in Equation 3 is very similar to that of Equation 2, with one important exception, the source of both the fuel HHV and EF. In this approach, no characteristics of the actual fuel are directly measured. Default values for both HHV and EF are used. For large GHG sources such as refineries, this approach would lead to an unacceptably large degree of error and thus this method was deemed inappropriate. This is especially true in the case of highly variable fuels such as refinery fuel gas. Thus it was determined that Equations 1 and 2 will provide an accurate $CO_2$ emissions accounting for stationary combustion $CO_2$ sources in the petroleum sector. Application of these two approaches is fuel specific and is discussed in detail below.

**95113(a)(1)(A) Refinery Fuel Gas**
Internally generated fuels represent a very significant proportion of the fuels routinely combusted in California refineries. The term “internally generated” refers to fuels such as refinery fuel gas (RFG) which are produced from the crude oil at various stages of the refining process. RFG is captured and used to fuel devices such as heaters, boilers and furnaces. Available data suggests that combustion of crude oil derived fuels such as RFG may represent approximately 40-50 percent of a typical refinery’s annual GHG emissions (CIIEDAC, 2007). Thus because combustion of RFG is so important in routine refinery operation, and is such a large source of refinery GHG emissions, it is evident that an accurate characterization of RFG is essential to the accuracy of GHG emissions determinations from the refinery sector.

RFG composition (heating value and carbon content) can vary significantly over both short (daily) and longer (monthly and seasonally) time scales as the processes which generate RFG continually evolve with plant operational parameters such as crude oil composition, seasonal changes in product requirements and daily operational parameters. In addition to the dynamic nature of operating scenarios in a refinery, an individual refinery may have numerous separate and distinct RFG systems (typically one to four). In general, distinctly different refining processes generate the RFG collected in each of the systems. Thus RFG characteristics vary significantly within a refinery from system to system as well as from refinery to refinery. We estimate that within the 21 refineries operating in the State of California, there may anywhere from 20 to 80 separate and distinct refinery fuel gas systems, each supplying gas with varying composition to a host of combustion devices. Finally, while the heating value and chemical composition of conventional fuels such as natural gas have been well characterized, the same cannot be said for RFG. While the heating value of RFG may be monitored routinely for process control purposes, fuel compositional (carbon content) data either in the form of fuel system specific emissions factors (mass of $CO_2$ emitted/Btu) or fuel carbon analysis is required to make accurate GHG emissions calculations. An additional complicating factor which affects our ability to accurately calculate RFG combustion GHG emissions is the fact that RFG may also be mixed with conventional fuels such as natural gas prior to combustion.

Because the chemical composition and heat content of RFG varies significantly, both within a refinery and from refinery to refinery, staff feels that the use of a default $CO_2$ emission factor will result in unacceptably large errors in emission calculations. The obvious solution to this problem is to calculate a $CO_2$ emission factor for each RFG fuel system. The use of a refinery fuel gas system specific emissions factor and a daily average fuel heating value, both measured quantities, helps to insure that 1) each RFG system in a refinery is well characterized and, 2) short term (daily) fluctuations in fuel composition are accounted for. Methodology adopted to accomplish this is found in section **95113(e)** and is shown in the equation below:

$$EF_{CO2} = CC/HHV \times MW_{CO2}/MVC \times \text{tonnes}/1000\text{kg}$$

Where:

$EF_{CO2}$ = daily $CO_2$ emissions factor (metric tonnes $CO_2/10^6$ Btu)
CC = carbon content (kg carbon/kg fuel or weight % carbon))
HHV = High Heating Value (Btu/scf)
$MW_{CO2}$ = molecular weight of $CO_2$
MVC = molar volume conversion (849.5 scf/kg-mole)
tonnes/100 kg = conversion from kg to metric tonnes

Carbon content shall be determined once per day and used with a measured HHV value to calculate a daily fuel system specific RFG $CO_2$ emission factor. HHV should be determined as part of the carbon content analysis if possible. An hourly average HHV value which coincides with the hour at which the carbon content sample was taken or the on-line analysis performed may also be used. This process will be carried out daily for each RFG fuel system. The daily EF will then be used with a daily average HHV value to calculate daily stationary combustion $CO_2$ emissions for each combustion source (or sources) utilizing RFG from each RFG system (Equation 2).

This methodology is designed to 1) allow refinery operators to calculate a $CO_2$ emission factor specific to each of their refinery fuel gas systems which then can be used to provide an accurate and consistent accounting of RFG stationary combustion $CO_2$ emissions while 2) providing reporters with a method which does not require the resource intensive measurements of the more rigorous method shown in Equation 1. Calculation of a RFG system specific factor will prevent significant over or underestimation of $CO_2$ stationary combustion emissions. This method is also consistent with other reporting protocols such as the IPCC (2006) and the European Union Emissions Trading Scheme (EU 2007). For process gas streams such as refinery fuel gas and coke oven gas, EU ETS policy dictates a frequency of analysis of "at least daily – using appropriate procedures at different parts of the day".

A very material GHG combustion source such as RFG where fuel composition is presently not well documented and potentially highly variable requires a rigorous accounting methodology. Without an accurate and consistent methodology to quantify emissions resulting from the combustion of refinery fuel gas we risk significantly over or under estimating $CO_2$ emission from this very material source. This methodology will require that refiners examine all their refinery fuel gas systems and install the necessary equipment (flow meters and sampling ports or in-line analytical equipment) to ensure that the measurements they make are free of bias and accurately represent the required fuel characteristics.

In cases where RFG is mixed with another fuel such as natural gas prior to combustion, reporters are provided with the option of determining carbon content of RFG and RFG fuel mixtures and calculating daily $CO_2$ emissions using the methods found in section **95125(f)**. Operators may characterize the fuels separately or they may measure HHV and carbon content or just carbon content using the prescribed fuel methods. The primary consideration must be that instrumentation placement and sampling locations provide unbiased and representative data with which emissions calculations are made.

As the mandatory reporting process generates industry wide RFG system $CO_2$ emission factor data, ARB will examine this data to determine if it may be possible to modify the required carbon content measurement frequency and provide reporters with sampling frequency options based on RFG composition variability and refinery operational parameters. Unfortunately, at the present time we do not have the data available to provide this guidance and the high degree of materiality of this source dictates an accurate accounting methodology which will require rigorous measurement strategies.

**(1) Natural Gas – Section 95125(c) or (d)**

RFG and natural gas are the two major fuels utilized in California refineries and thus combustion of these fuels contributes a very large fraction of total refinery $CO_2$ emissions. In contrast to RFG, natural gas composition is very uniform. The HHV and chemical composition of this fuel are well characterized by fuel suppliers and/or refinery operators. Industry standards dictate the acceptable range of natural gas heat content. Thus in most cases the emissions calculation method shown in Equation 2, with a default emission factor, will provide an accurate emissions accounting. Section 95125(c) requires natural gas HHV be determined on a monthly basis, either measured by the refinery or fuel supplier. Natural gas HHV values are typically made available to industrial, commercial and residential consumers by the fuel supplier, thus requiring no additional measurements by the refineries. For example, Pipe Ranger, a PG&E website, provides this information on a daily basis. An entity need only know their Btu area or 7 digit transit number to gain access to the appropriate data. The PG&E Pipe Ranger website may be accessed at the following web address: www.pge.com/pipeline/operations/gas_quality/index.shtml.

A default $CO_2$ emission factor supplied by ARB shall be used to calculate $CO_2$ emissions when pipe-line quality natural gas is combusted. The HHV of pipe line quality natural gas typically falls in the range of 975 – 1100 Btu/scf. A table of emission factors which cover this range is provided by ARB. These emission factors were derived from an analysis of 6,743 pipe-line quality natural gas collected in 26 cities located in 19 states (DOE/EIA, 1994). DOE observed an approximate 10 percent range of HHV values nationwide, and thus the use of a measured HHV rather than a default value (as in Equation 3 above) will help to insure an accurate emissions accounting. Outside this range, carbon content of the natural gas must be determined on a weekly basis, either by the refiner or fuel supplier. In this case refiners will be required to use Equation (1) method to calculate weekly $CO_2$ emissions. An examination of natural gas heating content data available on the PG&E Pipe Ranger web site reveals that very few (typically ≤ 4 percent) natural gas supply lines deliver gas outside the 975-1100 range.

**(1) Fuel Mixtures – Section 95125(f)**

In situations where fuels such as RFG are mixed with other fuels such as natural gas prior to combustion, two $CO_2$ emissions calculation methods are provided – **(95125(f)(A) and (B)).** Reporters may choose to measure the fuel flow rate and appropriate fuel factors such as HHV or carbon content of each fuel stream prior to mixing. They would then apply the appropriate fuel specific calculation methodology to derive emissions from each specific fuel stream and sum the results to calculate total emissions from the combustion device. Alternatively, they may measure the fuel mixture flow rate after mixing and apply the more rigorous calculation method shown above in Equation (1) and (4). Reporters may also measure the carbon content of fuel mixtures.

These alternatives were designed to provide reporters with some flexibility in determining where and how fuel flow and heat content/carbon content measurements are made, while ensuring that $CO_2$ emissions calculations remain rigorous. It is incumbent upon the reporter to measure flow and fuel characteristics at a location or locations which are free of bias and accurately characterize the fuel and flow rate of that fuel stream which is combusted at one or more devices.

(1) **Other Fuels - Section 95125(d)**

Many other fuels such as No 1 and 2 fuel oil, diesel fuel, gasoline, and kerosene may be combusted as part of refinery operations. Operators are required to determine the HHV of the fuel by fuel type and for the measurement period which is defined as from receipt of each new fuel shipment or delivery for the following fuels: middle distillates (diesel, fuel oil, and kerosene) residual oil, LPG (ethane, propane, isobutene, n-butane, unspecified LPG). Emissions are calculated using a default $CO_2$ emission factor supplied by ARB (Equation 2).

**(b) Stationary Combustion – $CH_4$ and $N_2O$ Section 95125(b)**
Emission of methane ($CH_4$) and nitrous oxide ($N_2O$) represent a very small fraction of total stationary combustion GHG emissions. Because of the low degree of materiality less rigorous methods are appropriate. Default emission factors are provided. Section 95113(b) of the Petroleum Refinery regulations directs reporters to section **95125 Additional Calculation Methods,** subsection **(b) Method for Estimating $CH_4$ and $N_2O$ Emissions from Fuel Combustion Using Default Emission Factors.** The calculation method specified in this section is consistent with CCAR protocols (GRP, Section III.8.4 Calculating Emissions from Stationary Combustion), IPPC 2006 guidelines (Volume 2 Energy, Chapter 2 Stationary Combustion, Section 2.3.1.3 Tier 3 approach), and DOE Technical Guidelines (Chapter 1, Part C: Stationary Combustion, 1.C.4 Common Sources: Methane and Nitrous Oxide).

**(c) Cogeneration**
**Section 95113(c) Cogeneration** refers reporters to section **95112 Reporting Requirements for Cogeneration Facilities.** The development of cogeneration facility reporting methodologies is discussed in the Cogeneration section of the Staff Report.

**(d) Process Emissions – 95113(a)(5)**
As stated in the introductory Background section above, process related GHG emissions represent a sizable fraction (typically ≥ 40 percent) of total refinery emissions. Process emissions are defined in the Definitions section **95102.**
Carbon dioxide, methane and nitrous oxide may be emitted from process vents and the magnitude and scope of these emissions vary widely with specific refinery operations. The following emission sources are ordered in terms of their relative magnitude of process related emissions. Not all of these processes may take place at all refineries.

**(1) Catalytic Cracking – 95113(d)(1)**
High temperature and pressure catalytic cracking is a very important step in the production of clean, high octane fuels. In general, catalytic cracking units take the heavier hydrocarbon fractions distilled from crude oils and break them down into lighter, more useful products. As part of this process, elemental carbon or coke is generated and this coke coats the catalyst, reducing its effectiveness. The catalyst thus requires regeneration which involves burning the carbon or coke off. The regeneration process generates large amounts of $CO_2$ which are subsequently released to the atmosphere. Regeneration can be done continually as in a fluidized catalytic cracking unit (FCCU) or periodically.

API presents two calculation methodologies for the determination of $CO_2$ process emissions resulting from catalyst regeneration. API states that these methods are "*based on process parameters that are generally monitored or estimated as part of routine refinery operation. Both process calculation approaches should provide equally accurate emission estimates*". The first API approach assumes that combustion of the coke proceeds to $CO_2$ (that is, very little CO is emitted) and is based on the determination of the coke burn rate. All refiners operating a catalytic cracking unit subject to Federal Regulation Title 40 (Chapter I, Part 63

National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units. Catalytic Reforming Units, and Sulfur Recovery Units), are required to calculate coke burn rate using methods specified in this Federal Regulation. California refiners are currently measuring the parameters required to calculate coke burn rate. This method will provide accurate and consistent emissions estimates for this important GHG source. Thus we propose to use an API method for the calculation of catalytic cracking related $CO_2$ emissions and incorporate the US EPA coke burn rate calculation method to insure consistency across California refineries.

EPA guidance from 40CFR Part 60 has also been included in the reporting regulation concerning the determination of the variable $Q_r$.

After reporters calculate the coke burn rate using the EPA methodology, $CO_2$ emissions resulting from catalyst regeneration will be calculated using the API methodology show below:

$$CO_2 = \sum_{0}^{n} (CR_{ave} \times H \times CF) \times 3.664 \times tonne/\ 1000\ kg$$

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
n = number of days operational during the reporting period
$CR_{ave}$ = average hourly coke burn rate (kg/hr)
H = hours of operation per day (hr)
CF = carbon fraction in coke burned
3.664 = conversion from carbon to carbon dioxide
tonne/1000 kg = conversion from kg to metric tonnes

Catalyst regeneration may also be done periodically. For instance, regeneration of catalytic reformer and hydroprocessing catalyst may be conducted on a periodic basis. Again we have chosen an API method for the calculation of these $CO_2$ emissions. This method which assumes complete conversion of catalyst carbon to carbon dioxide is shown below:

$$CO_2 = \sum_{0}^{n} CRR \times CF \times 3.664 \times tonne/1000\ kg$$

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
CRR = mass of catalyst regenerated per cycle (kg)
CF = weight fraction of carbon on the catalyst
n = number of regeneration cycles per year

**(2) Hydrogen Production - 95114**

The production of hydrogen is an integral part of typical refinery operations as hydrogen is essential to the production of clean transportation fuels. The hydrogen production process also produces significant quantities of $CO_2$ and may contribute 20 percent of the total GHG emissions of a large refinery. Section 95103 - The General Greenhouse Gas Reporting Requirements – provides guidance as to which entity reports GHG emissions for hydrogen production facilities. The company or organization having operational control of a facility is required to report emissions for the hydrogen facility.

The process of hydrogen production generates significant GHG emissions from both fuel combustion and from the reaction of the chemical feed stock (process emissions). Process emissions represent the largest GHG emissions source associated with hydrogen production. Several processes are used commercially to produce hydrogen: steam methane reforming (SMR), auto thermal reforming and partial oxidation. Each of these processes results in the release of the carbon contained in the feed stock as $CO_2$. Typically hydrogen is generated by steam reforming where a hydrocarbon or mixture of hydrocarbons is reacted with steam in the presence of a catalyst to form hydrogen and carbon dioxide as shown below:

$$C_xH_{(2x+2)} + 2xH_2O \rightarrow (3x + 1)H_2 + xCO_2$$

API presents two methodologies designed to quantify hydrogen production related $CO_2$ process emissions and states that both methods are rigorous. Staff has chosen the first of these methods, a feed stock mass balance approach for this calculation. This method, with one modification, will provide an accurate accounting of $CO_2$ process emissions under the operational conditions found in hydrogen plants. The second of the API approaches, based on hydrogen production rate, while valid under certain circumstances, would require significant modification and additional measurements to assure it's applicability under operational scenarios commonly employed in hydrogen plants.

Hydrogen plant operators are provided with three options for the calculation of combustion and process emissions. Operators may choose to quantify both combustion and process emissions using a Continuous Emission Monitoring System (CEMS). These systems must meet federal requirements contained in 40 CFR Part 75. Operators may also use the mass balance methodology to calculate both combustion and process emissions. This method requires that hydrogen plant operators accurately measure all fuel and feedstock flow rates and carbon content. This approach assumes that all the carbon entering the plant in both the fuel and feedstock is converted to $CO_2$. In some cases a fraction of the carbon may be diverted (e.g. to a refinery fuel gas system or a flare). The mass balance methodology includes a term which allows for operators to account for this diverted carbon which is accounted for by other methods in these regulations to avoid the possibility of double counting these emissions. Finally, hydrogen plant operators may choose to calculate combustion and process emissions separately.

The mass balance based method we have chosen does require knowledge of the feedstock chemical composition and this can be complicated by the fact that various feed stocks are used to produce hydrogen, either singly or as mixtures. Natural gas, naphtha, pentane, and refinery fuel gas are just some of the species used as feed stocks in hydrogen plants. The calculation methodology for process related $CO_2$ emissions is shown below:

$$CO_2 = \sum_{0}^{n} ((FSR \times CF) - S) \times 3.664 \times \text{tonne}/1000 \text{ kg}$$

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
FSR = feed stock supply rate (kg/day)
CF = carbon fraction in feed stock (kg C/kg feed stock)
S = carbon fraction diverted and accounted for elsewhere (kg C/day)
3.664 = conversion factor (carbon to carbon dioxide)
n = days of operation

An additional term (S) has been added to the original API derivation. This term was added at the request of hydrogen plant operators and is included to avoid double-counting of some $CO_2$ process emissions associate with hydrogen production. The application of factor S (the carbon fraction diverted and accounted for elsewhere) is limited to situations where $CO_2$ emissions are accounted for using other methodologies in the regulations. The SMR reaction does not go to completion and thus the gas stream exiting the hydrogen production unit is a mixture of compounds which must be purified in order to produce the required high purity hydrogen product. In the most typical purification process, pressure swing adsorption (PSA), the gas stream is routed sequentially through up to 12 vessels containing solid absorbents. This purification process generates an off-gas stream containing varying amounts of $H_2$, $CH_4$, $CO_2$, $H_2$, $N_2$ and CO. This off-gas may 1) be routed directly back to the hydrogen plant process heaters; 2) it may be directed into the refinery fuel gas system to be combusted in any number of combustion devices throughout the refinery or 3) it may be sent to a flare. If the purification off-gas is routed into the RFG system, the S term should be used to account for this fact to avoid double counting as this carbon will be accounted for elsewhere. If hydrogen plant operators chose not to recover the energy contained in the off-gas stream, the PSA off-gas stream may be routed to a flare for destruction. In this case, combustion emissions will be accounted for using the flare reporting methods found in section **95113(f).** Thus, in this case it is appropriate to use the S factor to avoid double-counting.

If the off-gas stream is used as a fuel in the hydrogen plant boilers or heaters it would not be appropriate to use the S correction term (S = 0) as the mass balance equation will account for $CO_2$ combustion emissions of the off-gas stream.

Hydrogen plant stationary fuel combustion emissions of $CO_2$, $CH_4$ and $N_2O$ shall be reported as described in Sections 95113(a) and (b) and the development of these methods is discussed above.

Hydrogen plant operators may also sell carbon dioxide to third parties. The EU ETS refers to this as “transferred $CO_2$” and provides a number of examples of transferred $CO_2$:

“pure $CO_2$ used for the carbonation of beverages:
pure $CO_2$ used to produce dry ice;
pure $CO_2$ used as a fire extinguishing agent, refrigerant or laboratory gas:
pure $CO_2$ used for grain disinfestation.”

At the request of industry stakeholders a provision has been added to the regulations to provide for reporting of these sales. At the present time, transferred $CO_2$ may not be subtracted from facility emissions. The definition of avoided or off-set emissions and the establishment of accounting procedures for these types of emissions is not the intent of this Article. While it is important to quantify GHG pools such as transferred $CO_2$, these accounting related issues will be dealt with as other aspects of the California Global Warming Solutions Act of 2006 move forward.

**(3) Process Vents**

Process emissions from “cold” (not directly related to combustion) vents may be a source of $CO_2$ and $CH_4$. An example is emissions occurring when emergency shutdown systems vent to an uncontrolled atmospheric blowdown system and the gas stream is vented directly to the atmosphere. An API material balance method has been adopted to calculate process vent emissions.

$$E_x = \sum_{0}^{n} VR \times F_x \times MW_x / MVC \times VT \times \text{tonnes}/1000\text{ kg}$$

Where;

$E_x$ = emissions of GHG gas (x = $CO_2$, $CH_4$, $N_2O$) (metric tonnes/yr)
VR = vent rate (scf/unit time)
$F_x$ = molar fraction of X in vent gas stream
$MW_x$ = molecular weigh of X (kg/kg-mole)
MVC = molar volume conversion (849.5 scf/kg-mole)
VT = time duration of venting
n = number of venting vents
tonnes/1000 kg = conversion factor – kg to metric tonnes

**(4) Asphalt Production**

GHG emissions result from the refinery based production of asphalt products, both from stationary combustion of fuels and from the asphalt blowing process where heated air is blown through asphalt to polymerize and stabilize the resulting product. Stationary combustion emissions shall be calculated as shown in section 95113(e) and 95113(b). California AQMD/APCD regulations prohibit uncontrolled asphalt blowing, that is the directed release of emissions to the atmosphere, and require refiners to direct emissions to a destruction device such as an incinerator. Consequently, emissions will be predominantly in the form of $CO_2$ resulting from the incineration of the hydrocarbons released during the blowing process. If asphalt blowing emissions are not directed to a flare where combustion and fugitive emissions are reported as prescribed in section 95113(f), these GHG emissions shall be reported in the following manner:

$$CO_2 = MA \times EF \times MW_{CH4}/MVC \times DE \times 2.743 \times tonne/1000\ kg$$

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
MA = mass of asphalt blown ($10^6$ bbl/yr)
EF = emission factor (default = 2,555 scf $CH_4/10^6$ bbl)
$MW_{CH4}$ = $CH_4$ molecular weight (16.04 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg-mole)
DE = destruction efficiency (default = 1)
2.743 = conversion factor – methane to carbon dioxide
tonne/1000 kg = conversion factor – kg to metric tonnes

API discusses emissions from asphalt blowing and suggests a similar GHG emissions calculation method employing an EPA (AP-42) derived emission factor. The default emission factor stipulated in these regulations was derived from the US EPA (2007).

**(5) Sulfur Recovery**

As requirements for clean transportation fuels become more stringent and the sulfur content of available crude oil supplies increases, sulfur recovery from crude oil becomes more important. Numerous gas streams are directed to refinery sulfur recovery units (SRU) where sulfur contained in compounds such as $H_2S$, COS and $CS_2$ is converted to elemental sulfur. SRUs remove and thus reduce emissions of toxic sulfur compounds such as $H_2S$ and also produce a commercial product, elemental sulfur.

Along with the sulfur containing species, hydrocarbons and $CO_2$ enter the sulfur removal processes. The configuration of sulfur recovery operations vary from refinery to refinery. Typically, gases are routed first to an amine gas sweeter, then through the Claus conversion process, and finally to a tail-gas treatment process. Entrained carbon dioxide may be emitted as the amine is heated and regenerated, or it may “slip” through the amine process, pass through the Claus reactor and be released in the tail-gas treatment along with entrained hydrocarbons oxidized to $CO_2$ in the Claus unit. An API derived mass balance methodology was adopted to calculate SRU $CO_2$ process emissions. This method is shown below:

$$CO_2 = \sum_{0}^{n} FR \times MW_{CO2}/MVC \times MF \times tonne/1000\ kg$$

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
FR = volumetric flow rate to the SRU (scf/day)
$MW_{CO2}$ = molecular weight of $CO_2$ (44 kg/kg-mole)
MVC = molar volume conversion (849.5 scf/kg-mole)
MF = weight fraction of $CO_2$ in sour gas (default = 0.20)
n = number of days of operation in reporting period

The method shown is drawn from the API. It was designed to account for $CO_2$ emissions from amine based sour gas treatment of gas streams such as natural gas. However, a material balance approach such as this is also valid for calculating $CO_2$ emissions from refinery based SRU operations. The difficulty encountered with this method is in the determination of the factor MF, the weight fraction of $CO_2$ in the gas entering the SRU process. EPA suggest that typical Claus tailgas composition before application of control devices "*may contain about 12 percent $CO_2$ and much smaller amounts of carbon containing species such as COS and $CS_2$*" (EPA, 1996). This average value does not consider $CO_2$ removed and emitted during the amine stripping prior to the Claus unit however and AP-42 does not present an emission factor for $CO_2$.

In a 1998 report ARPEL (Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean) state that $CO_2$ emissions do result from the combustion of hydrocarbons in the SRU feed, and/or from $CO_2$ in the feed. They suggest that in the absence of plant specific data, $CO_2$ emissions from an SRU be estimated by multiplying the sulfur production by 0.1374. They also note that this includes only $CO_2$ resulting from the combustion of hydrocarbons in the SRU, not $CO_2$ released from the acid gas during the amine stripping process.

It would not be appropriate to require reporters monitor carbon content for a small GHG source such as this and thus we have decided to adopt a conservative default value of 20 percent by weight $CO_2$ in the absence of plant specific data. Complete combustion of hydrocarbons to carbon dioxide is assumed and thus the only additional data required is the volumetric flow rate to the refinery SRU to calculate $CO_2$ emissions as shown below:

$$CO_2 = \sum FR \times MW_{CO2}/MVC \times MF \times tonne/1000\ kg$$

Where:

$CO_2$ = carbon dioxide emissions (metric tonnes/year)
FR = volumetric flow rate to SRU (scf/day)
$MW_{CO2}$ = molecular weight of $CO_2$ (44 kg/kg-mole)
MVC = molar volume conversion ( 848.5 scf/kg-mole)
MF = molecular fraction of $CO_2$ in sour gas and Claus tail gas (default = 20%)
tonne/1000 kg = conversion factor – kg to metric tonne

In an effort to address concerns that the default emissions factor may not be appropriate for all SRU gas streams, we have included a provision which allows operators to use an ARB approved sampling method to develop a site specific emission factor.

**Fugitive Emissions**

(1)Wastewater Treatment
Refineries use large amounts of water for cooling purposes, as boiler feed, and in process units such as crude oil desalting operations. CEC (2005) estimates that

California refineries in the year 2000 used between 20 - 60 gallons of water per barrel of crude processed or 40 -120 million gallons in total. GHG emission accounting methodologies for both wastewater treatment and oil/water separator operations are include in the regulations. Methods adopted for the calculation of GHG emissions from wastewater treatment are discussed in this section.

The large amounts of water used in a refinery must be treated prior to discharge and treatment may result in the emissions of GHG such as $CH_4$ and $N_2O$. Some fraction of this treatment takes place at the refinery and additional treatment may occur at municipal water treatment facilities. The $CH_4$ and $N_2O$ emissions calculation methods included in these regulations deal only with GHG emissions resulting from on-site treatment prior to release to a domestic treatment facility or discharge.

The CCAR GRP does not provide specific guidance for calculating GHG emissions resulting from the treatment of industrial wastewater. API presents a relatively simple EPA method for calculating $CH_4$ emissions based on BOD (biological oxygen demand) and also mentions the 2000 IPCC method which is based on COD (chemical oxygen demand). We have adopted the updated 2006 IPCC method (IPCC 2006b) for estimating $CH_4$ emissions from industrial wastewater treatment. The magnitude of $CH_4$ emissions will be dependent on the degree of anaerobic treatment and the IPCC 2006 approach (which is essentially identical to the IPCC 2000 method discussed in API) includes a factor which allows the reporter to estimate the fraction of waste treated anaerobically. The IPCC 2006 method included in the regulations for the calculation of $CH_4$ emissions from industrial wastewater treatment is shown below:

$$CH_4 = [(Q \times COD) - S] \times B \times MCF \times \text{tonne}/1000\text{ kg}$$

Where:

- $CH_4$ = emissions of $CH_4$ (metric tonnes/yr)
- Q = volume of wastewater treated ($m^3$/yr)
- COD = chemical oxygen demand of wastewater (kg/$m^3$)
- S = organic component removed as sludge (kg COD/yr)
- B = methane generation capacity (default = 0.25 kg $CH_4$/kg COD)
- MCF = methane conversion factor for the anaerobic decay (0 – 1.0)

A table taken from IPCC 2006 is included in the regulations to aid in the determination of a methane conversion factor appropriate for the conditions present at the refinery wastewater treatment facility. If methane is recovered from refinery wastewater treatment facilities and routed to a destruction device such as a flare and emissions from the flare device are accounted for in section 95113(f) of these regulations, $CH_4$ emissions shall not be reported here to avoid double-counting. The IPCC MCF table is shown below:

| Default MCF values for Industrial Wastewater (IPCC, 2006) | | | |
|---|---|---|---|
| **Type of treatment and discharge pathway or system** | **Comments** | **MCF** | **Range** |
| **Untreated** | | | |
| Sea, river and lake discharge | | 0.1 | 0 – 0.2 |
| **Treated** | | | |
| Aerobic treatment plant | Must be well managed. Some $CH_4$ can be emitted from settling basins and other pockets | 0 | 0 – 0.1 |
| Aerobic treatment plant | Not well managed. Overloaded | 0.3 | 0.2 – 0.4 |
| Anaerobic digester for sludge | $CH_4$ recovery not considered here | 0.8 | 0.8 – 1.0 |
| Anaerobic reactor (e.g., UASB, Fixed Film) | $CH_4$ recovery not considered here | 0.8 | 0.8 – 1.0 |
| Anaerobic shallow lagoon | Depth less than 2 meters, use expert judgment | 0.2 | 0 – 0.3 |
| Anaerobic deep lagoon | Depth more than 2 meters | 0.8 | 0.8 – 1.0 |

Nitrous oxide is also released to the atmosphere from wastewater treatment facilities. Refinery wastewaters may contain significant quantities of N containing compounds such as ammonia ($NH_3$) and $N_2O$ is an intermediate product in the nitrification-denitrification cycle. API does not provide guidance for this small GHG source. The IPCC 2006 (Volume 5 Waste) document does discuss $N_2O$ emissions, stating that aerobic treatment facilities with nutrient removal are small but distinct sources of $N_2O$. The IPCC 2006 method for the calculation of these $N_2O$ emissions has been included in the regulations and is shown below:

$$N_2O = N_{eff} \times EF_{eff} \times 1.571 \times \text{tonnes}/1000\ \text{kg}$$

Where:

$N_2O$ = emission of $N_2O$ (metric tonnes/yr)
$N_{eff}$ = nitrogen in the effluent discharged (kg N/yr)
$EF_{eff}$ = emission factor for $N_2O$ emissions from wastewater (kg $N_2O$-N/kg N)
1.571 = conversion factor - kg $N_2O$-N to kg $N_2O$
tonnes/1000 kg = conversion factor - kg to metric tonnes

(1) Oil/Water Separators

The first step in refinery wastewater treatment is typically the removal of gross quantities of oil and suspended solids from the wastewater prior to downstream treatment. This is usually accomplished in an oil/water separator and VOC emissions are associated with this treatment step. API does not provide guidance in this area but a simple method to calculate non-methane volatile organic compounds (NMVOC) is available from an April 2007 CONCAWE publication. CONCAWE (Conservation of Clean Air and Water in Europe) is described as "the oil company's European association for environmental, health and safety in refining and distribution". This method is shown below:

$$E_{NMVOC} = EF_{sep} \times V_{H2O}$$

Where:

$E_{NMVOC}$ = emissions of NMVOC (kg/yr)
$EF_{sep}$ = emissions factor for the type of separator (kg NMVOC/$m^3$ wastewater treated)
$V_{H2O}$ = volume of wastewater treated ($m^3$/yr)

The reporter is provided with CONCAWE derived emission factors for a range of separators and these EFs are shown in the table below:

| **Separator Type** | **Emission Factor** ($EF_{sep}$)[1] kg NMVOC/$m^3$ wastewater treated |
|---|---|
| Gravity type - uncovered | 1.11e-01 |
| Gravity type - covered | 3.30e-03 |
| Gravity type – covered and connected to destruction device | 0 |
| DAF[2] or IAF[3] - uncovered | 4.00e-03[4] |
| DAF or IAF - covered | 1.20e-04[4] |
| DAF or IAF – covered and connected to a destruction device | 0 |

1. EFs do not include ethane
2. DAF = dissolved air flotation type
3. IAF = induced air flotation type
4. the emission factors for these types of separators apply where they are installed as secondary treatment systems

A number of factors must be considered when calculating potential GHG emissions based on NMVOC emissions calculated using the CONCAWE methodology.

In cases where NMVOC emissions from covered gravity, DAF or IAF separators are directed to a destruction device, it is incumbent on the reporter to determine whether $CO_2$ emissions from the combustion/destruction of these compounds is captured under the flare reporting method in regulation section 95113(f). If they are, these emissions should not be reported here to avoid double-counting. If separator derived NMVOC combustion emissions are not accounted for as part of the flare reporting, that is they are routed to a destruction device such as an incinerator, where emissions are not reported to the local AQMD/APCD, they must be reported here. To accomplish this, the reporter must first calculate the carbon fraction in NMVOC. We have adopted a default factor of 0.6 from the IPCC 2006 Guidelines for National Greenhouse Gas

Inventories. A destruction efficiency must also be used in order to calculate the resulting $CO_2$ emissions from the destruction of the NMVOC emitted from the oil/water separator. A conservative default value of 100 percent will be assumed. Thus to calculate $CO_2$ emissions resulting from the combustion of NMVOCs emitted from covered oil/water separators (not calculated in section 95113(f) Flaring) operators shall use the following method:

$$CO_2 = EF_{sep} \times V_{H2O} \times CF \times DE \times \text{tonnes}/1000\ \text{kg}$$

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
$EF_{sep}$ = emissions factor for the type of separator (kg NMVOC/$m^3$ wastewater treated)
$V_{H2O}$ = volume of wastewater treated ($m^3$/yr)
CF = conversion factor – carbon fraction in NMVOC (default = 0.6)
DE = NMVOC destruction efficiency (default = 1)

In the case of uncovered oil/water separators where emissions vent to the atmosphere, we have used guidance from the same IPCC 2006 Guidelines. In this case IPCC directs that $CO_2$ emissions resulting from the oxidation of NMVOCs to $CO_2$ be reported as follows:

$$ECO_2 = EFsep \times V_{H2O} \times C \times 3.664 \times \text{tonnes}/1000\ \text{kg}$$

Where:

$ECO_2$ = emissions of $CO_2$ (metric tonnes/yr)
$EF_{sep}$ = emissions factor for the type of separator (kg NMVOC/$m^3$ wastewater treated)
$V_{H2O}$ = volume of wastewater treated ($m^3$/yr)
C = carbon fraction in NMVOC (default = 0.6)
3.664 = conversion – carbon to carbon dioxide
tonnes/1000 kg = conversion factor – kg to metric tonnes

The default value of 0.6 for the carbon fraction contained in NMOC was derived from IPCC (2006) Guidelines (Volume 1: General Guidance and Reporting, Chapter 7 Precursors and Indirect Emissions).

(2) Storage Tanks

Emissions of VOCs including methane occur as a consequence of refinery operations and sources such as crude oil storage tanks have been discussed and documented in a number of publications (Rao et al., 2005; Kihlman et al., 2006; IMPEL, 2000; Environment Canada, 2006; Coburn 2002). These emissions are most important in the oil and gas production areas where installation of vapor recovery units (VRU) has proven very effective in recovering economically important quantities of methane, VOCs, natural gas liquids, and hazardous air pollutants which vaporize from crude oil stocks. In fact the US EPA Natural Gas STAR Program (2003) has demonstrated that VRU installation payback times can be as short as 3 months. Methane and VOC emissions from crude oil storage tanks are largest in oil and gas production fields, and while these emissions decrease as the crude oil moves from the production fields to the refinery, considerable effort is made to reduce and capture these emissions during crude loading, transit and unloading (MARINTEK, 2004). The current refining capacity of the 21 California refiners is over 2 million barrels of crude oil per day, and thus annually, over 700 million barrels (30 billion gallons) of crude oil is off-loaded, stored, and processed in California refineries. The movement and storage of such a large volume of crude oil must certainly result in emissions of methane. California AQMD/APCDs (BAAQMD, 2006; SCAQMD, 2006) have also devoted considerable effort to reduce these emissions and thus many refineries have installed VRUs on their crude oil storage tanks.

Models for calculating storage tank emissions have been developed by API (E&P TANK Version 2.0, 2000) and by the US EPA (TANKS Version 4.09D, 2005). Staff examined both these models. API staff indicated that the API E&P TANK model is more appropriate for the up-stream oil and gas exploration and production sector (T. Shires , personnel communication, 2007). Thus it was determined that the EPA TANKS model (Version 4.09D, 2005, USEPA 2005) which is available at no-cost from the US EPA will be used to calculate methane emissions from crude oil and asphalt storage tanks which are not equipped with VRUs. This model is based upon procedures from Chapter 7 of EPA's Compilation of Air Pollutant Emission Factors (AP-42). Program features include on-line help for every screen, an extensive *Frequently Asked Questions* selection and output in the form of a detailed report. It is available, along with a user's manual, at the following website: www.epa.gov/ttn/chief/software/tanks/index.html (accessed 9/15/07)

(3) Equipment Fugitive Emissions

Fugitive emissions are, by their very nature, difficult to detect and quantify and thus there remains a relatively high degree of uncertainty as to the magnitude of fugitive emissions emitted from petroleum refinery operations. A recent EPA workshop focused on new fugitive monitoring technology and potential gaps which currently exist in policy concerning fugitive emissions. A quote from the Executive Summary of this workshop (US EPA, 2006) provides some insight into the current state of our understanding of fugitive emissions - "*studies performed in Europe over the past decade, more recently in Canada, indicate that emissions from refinery and natural gas operations may be 10 to 20 times greater than the amount estimated using standard emission factors*". API states in the Compendium that "*an on-going API study is testing the hypothesis that $CH_4$ fugitive emissions from the refinery fuel gas system are negligible*".

As discussed above, refinery fuel gas and natural gas, both fuels containing significant quantities of methane (50-98 percent) are the two primary fuels combusted in California refineries. In an effort to decrease VOC emissions from refineries, California AQMD and APCDs currently require that refiners establish leak detection and repair (LDAR) programs (SCAQMD, 2003: BAAQMD, 2004, SJVUAPCD, 2005). These LDAR programs are based on EPA Method 21 – *Determination of Volatile Organic Compound Leaks*, which utilizes a handheld organic vapor analyzer (OVA) to screen and document leaking fittings such as valves, flanges, connections, pumps and compressors, pressure relief valves, process drains, open-ended valves etc. API identifies the LDAR method as the preferred approach for estimating fugitive emissions. The EPA Emissions Inventory Improvement Program (EPA, 1996) also incorporates a LDAR based emission inventory approach. Recognizing that California refineries currently have established LDAR programs and that EPA Method 21 is the accepted methodology for screening leaking components, we have chosen to use a CAPCOA/CARB (1999) method for estimating emissions at petroleum refineries which is also based on EPA Method 21 LDAR procedures.

Currently, AQMD/APCD LDAR regulations do not require refineries to screen natural gas and refinery fuel gas components because $CH_4$ is not considered to be a VOC contributing to ozone formation. Thus, while refiners do posses the necessary equipment and expertise, extension of existing LDAR screening procedures to fuel gas components will require additional effort by refinery staff.

**(f) Flaring**

Flaring at refineries serves as a safety measure to prevent volatile gases from being released directly to the atmosphere. Excess fuel gas, process gas emitted during start-up and shut-down of refinery equipment, and emergency releases are routed to a flare and combusted. Refinery facilities such as hydrogen plants and sulfur recovery units often flare emissions. California AQMD/APCDs have initiated rules and regulations to monitor and minimize flaring and require refineries to report emissions from flaring operations (BAAQMD, 2003, 2007; SJVUAPCD, 2006; SCAQMD, 2005). GHG emissions from flares result from the combustion of pilot gas used to maintain the presence of a flame for ignition, emissions of uncombusted hydrocarbons, combustion of gases sent to the flare from refinery operations, and in some instances combustion of purge gas (e.g. natural gas) which is introduced to the flare to maintain an inert atmosphere in the flare stack thus avoiding explosive situations and limiting combustion to the flare tip region.

All refinery operators shall report $CO_2$, $CH_4$, and $N_2O$ combustion emissions from the combustion of flare pilot and purge gas using standard stationary combustion calculation methods previously discussed above.

In the case of flare emissions resulting from the combustion of process gases sent to the flare, API guidance recommends the use of test data or vendor specific information as their preferred method for estimating flare GHG emissions. The methods specified in the regulations are consistent with API recommendations in that they utilize test data already provided to the AQMD/APCDs and thus should not impose any additional sampling or analytical burdens on refinery operators. Three GHG reporting methods are specified in these regulations. Refinery operators shall chose the appropriate method based on currently applicable AQMD/APCD flare monitoring and reporting requirements in their district. There are thirteen refineries located in the South Coast Air Quality District, five in the Bay Area Air Quality Management District, and three in the San Joaquin Valley Unified Air Pollution Control District.

As an example, BAAQMD refineries are subject to *Rule 12-11 – Miscellaneous Standards of Performance, Flare Monitoring at Petroleum Refineries*. Rule 12-11 requires monitoring and reporting of total hydrocarbons and methane in flare vent gases. Bay Area refineries subsequently generate a daily emissions summary where vent gas flow, sulfur dioxide, NMHC and methane emissions are reported. Monthly summary reports are publicly available on a website maintained by the BAAQMD (www.baaqmd.gov/enf/flares/ - accessed 9/16/07). In this case, reporters would use method 951139(f)(2)(A) shown below:

$CO_2$ = ∑ [($CF_{NMHC}$ x [NMHC x 1/1-FE]) x 3.664 + ($CH_4$ x 1/1-FE) x 2.197] x tonne/1000 kg

Where:

$CO_2$ = emissions of $CO_2$ (metric tonnes/yr)
$CF_{NMHC}$ = carbon fraction in NMHC (0.6 default value)
NMHC = flare non-methane hydrocarbon emissions (kg/day)
3.664 = conversion factor – carbon to carbon dioxide
FE = flare destruction efficiency (e.g. 98% = 0.98)
$CH_4$ = flare methane emissions (kg/day)
2.197 = conversion factor methane to carbon dioxide
tonne/1000 kg = conversion factor – kilogram to metric tonne

The $CF_{NMHC}$ conversion factor (0.6) was derived from IPCC (2006) Guidelines (Volume 1, Chapter 7 Precursors and Indirect Emissions)

The flare efficiency term (1/1-FE) scales reported emissions of NMHC and $CH_4$ to calculate the amount that was actually combusted. Reporters choose one of two default FE values which are based on the HHV of flared gases. These FE values were recommended by BAAQMD staff based on their experience at refineries in the Bay Area.

| **Vent Gas HHV (Btu/scf)** | **Default Flare Efficiency (percent)** |
|---|---|
| <200 | 98 |
| > 200 | 93 |

Similar calculation methods (95113(f)(2)(B) are provided for SCAQMD refiners required to report Reactive Organic Gases (ROG).

San Joaquin Valley refiners are subject to Rule 4311 which requires annual source testing for VOC and $NO_x$. In this case (95113(f)(2)(C)) operators shall use an emission factor based on refinery through-put. We have adopted the European Environment Agency (2006) NMHC emission factor of 0.002 kg/$m^3$ of refinery feed, assumed a flare destruction efficiency of 98 percent, and a NMHC to carbon conversion factor of 0.6 (IPCC, 2006), to calculate $CO_2$ emissions as shown below:

$$CO_2 = RT \times EF_{NMHC} \times CF_{NMHC} \times 1/1\text{-}FE \times 3.664 \times \text{tonne}/1000\ \text{kg}$$

Where:

$CO_2$ = emission of $CO_2$ (metric tonnes/year)
RT = refinery feed through-put ($m^3$/year)
$EF_{NMHC}$ = emission factor for refinery flares (kg NMHC/$m^3$ of refinery feed)
$CF_{NMHC}$ = conversion factor – NMHC to carbon
FE = flare destruction efficiency (default FE = 98%)(98% = 0.98)
3.664 = conversion factor (carbon to carbon dioxide)
tonne/1000 kg = conversion factor (kg to metric tonnes)

**(g) Indirect Energy Purchases**
Refinery and hydrogen plant operators are required to report indirect energy purchases as specified in sections 95125(k-l). These sections are discussed elsewhere in this Staff Report.

## The Oil and Gas Exploration and Production Sector

Under the current regulatory framework, facilities that are part of the upstream sector of the petroleum industry, oil and gas exploration and production, are required to report GHG emissions if their stationary combustion emissions exceed the threshold of 25,000 metric tonnes of $CO_2$ annually.

Section 95115(b) directs these facilities to the appropriate regulatory reporting sections. Reporting requirements for these facilities are identical to those discussed above for the refining sector. The E&P General Stationary Combustion facilities are required to report all stationary combustion emissions as well as emissions associated with cogeneration and hydrogen production. Reporting methods covering other aspects of this sector such as fugitive emissions will be included in subsequent modifications to the present regulation.

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# APPENDIX F

# TEXT OF ASSEMBLY BILL 32

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BILL NUMBER: AB 32 CHAPTERED
BILL TEXT

CHAPTER 488
FILED WITH SECRETARY OF STATE SEPTEMBER 27, 2006
APPROVED BY GOVERNOR SEPTEMBER 27, 2006
PASSED THE ASSEMBLY AUGUST 31, 2006
PASSED THE SENATE AUGUST 30, 2006
AMENDED IN SENATE AUGUST 30, 2006
AMENDED IN SENATE AUGUST 23, 2006
AMENDED IN SENATE AUGUST 9, 2006
AMENDED IN SENATE AUGUST 7, 2006
AMENDED IN SENATE JUNE 22, 2006
AMENDED IN SENATE APRIL 18, 2006
AMENDED IN SENATE AUGUST 15, 2005
AMENDED IN ASSEMBLY MARCH 31, 2005

INTRODUCED BY Assembly Members Nunez and Pavley
(Principal coauthor: Assembly Member Nation)
(Coauthors: Assembly Members Arambula, Baca, Bass, Berg, Bermudez, Calderon, Chan, Chavez, Chu, Cohn, Coto, De La Torre, Dymally, Evans, Frommer, Goldberg, Hancock, Jerome Horton, Jones, Karnette, Klehs, Koretz, Laird, Leno, Levine, Lieber, Lieu, Montanez, Mullin, Nava, Oropeza, Ridley-Thomas, Ruskin, Saldana, Salinas, Torrico, Vargas, Wolk, and Yee)
(Coauthors: Senators Alarcon, Bowen, Chesbro, Escutia, Figueroa, Kehoe, Kuehl, Lowenthal, Migden, Romero, Simitian, Soto, Speier, Torlakson, and Vincent)

DECEMBER 6, 2004

An act to add Division 25.5 (commencing with Section 38500) to the Health and Safety Code, relating to air pollution.

LEGISLATIVE COUNSEL'S DIGEST

AB 32, Nunez Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006.

Under existing law, the State Air Resources Board (state board), the State Energy Resources Conservation and Development Commission (Energy Commission), and the California Climate Action Registry all have responsibilities with respect to the control of emissions of greenhouse gases, as defined, and the Secretary for Environmental Protection is required to coordinate emission reductions of greenhouse gases and climate change activity in state government.

This bill would require the state board to adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program, as specified. The bill would require the state board to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020, as specified. The bill would require the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions, as specified. The bill would authorize the state board to adopt market-based compliance mechanisms, as defined, meeting specified requirements. The bill would require the state board to monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board, pursuant to specified provisions of existing law. The bill would authorize the state board to adopt a schedule of fees to be paid by regulated sources of greenhouse gas emissions, as specified.

Because the bill would require the state board to establish emissions limits and other requirements, the violation of which would be a crime, this bill would create a state-mandated local program.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

THE PEOPLE OF THE STATE OF CALIFORNIA DO ENACT AS FOLLOWS:

SECTION 1. Division 25.5 (commencing with Section 38500) is added to the Health and Safety Code, to read:

DIVISION 25.5. CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006

PART 1. GENERAL PROVISIONS

CHAPTER 1. Title of Division

38500. This division shall be known, and may be cited, as the California Global Warming Solutions Act of 2006.

CHAPTER 2. Findings and Declarations

38501. The Legislature finds and declares all of the following:

(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems.

(b) Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state.

(c) California has long been a national and international leader on energy conservation and environmental stewardship efforts, including the areas of air quality protections, energy efficiency requirements, renewable energy standards, natural resource conservation, and greenhouse gas emission standards for passenger vehicles. The program established by this division will continue this tradition of environmental leadership by placing California at the forefront of national and international efforts to reduce emissions of greenhouse gases.

(d) National and international actions are necessary to fully address the issue of global warming. However, action taken by California to reduce emissions of greenhouse gases will have far-reaching effects by encouraging other states, the federal government, and other countries to act.

(e) By exercising a global leadership role, California will also position its economy, technology centers, financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases. More importantly, investing in the development of innovative and pioneering technologies will assist California in achieving the 2020 statewide limit on emissions of greenhouse gases established by this division and will provide an opportunity for the state to take a global economic and technological leadership role in reducing emissions of greenhouse gases.

(f) It is the intent of the Legislature that the State Air Resources Board coordinate with state agencies, as well as consult with the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing this division.

(g) It is the intent of the Legislature that the State Air Resources Board consult with the Public Utilities Commission in the development of emissions reduction measures, including limits on emissions of greenhouse gases applied to electricity and natural gas providers regulated by the Public Utilities Commission in order to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements.

(h) It is the intent of the Legislature that the State Air Resources Board design emissions reduction measures to meet the statewide emissions limits for greenhouse gases established pursuant to this division in a manner that minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality.

(i) It is the intent of the Legislature that the Climate Action Team established by the Governor to coordinate the efforts set forth under Executive Order S-3-05 continue its role in coordinating overall climate policy.

## CHAPTER 3. Definitions

38505. For the purposes of this division, the following terms have the following meanings:

(a) "Allowance" means an authorization to emit, during a specified year, up to one ton of carbon dioxide equivalent.

(b) "Alternative compliance mechanism" means an action undertaken by a greenhouse gas emission source that achieves the equivalent reduction of greenhouse gas emissions over the same time period as a direct emission reduction, and that is approved by the state board. "Alternative compliance mechanism" includes, but is not limited to, a flexible compliance schedule, alternative control technology, a process change, or a product substitution.

(c) "Carbon dioxide equivalent" means the amount of carbon dioxide by weight that would produce the same global warming impact as a given weight of another greenhouse gas, based on the best available science, including from the Intergovernmental Panel on Climate Change.

(d) "Cost-effective" or "cost-effectiveness" means the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential.

(e) "Direct emission reduction" means a greenhouse gas emission reduction action made by a greenhouse gas emission source at that source.

(f) "Emissions reduction measure" means programs, measures, standards, and alternative compliance mechanisms authorized pursuant to this division, applicable to sources or categories of sources, that are designed to reduce emissions of greenhouse gases.

(g) "Greenhouse gas" or "greenhouse gases" includes all of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexaflouride.

(h) "Greenhouse gas emissions limit" means an authorization, during a specified year, to emit up to a level of greenhouse gases specified by the state board, expressed in tons of carbon dioxide equivalents.

(i) "Greenhouse gas emission source" or "source" means any source, or category of sources, of greenhouse gas emissions whose emissions are at a level of significance, as determined by the state board, that its participation in the program established under this division will enable the state board to effectively reduce greenhouse gas emissions and monitor compliance with the statewide greenhouse gas emissions limit.

(j) "Leakage" means a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.

(k) "Market-based compliance mechanism" means either of the following:

(1) A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases.

(2) Greenhouse gas emissions exchanges, banking, credits, and other transactions, governed by rules and protocols established by the state board, that result in the same greenhouse gas emission reduction, over the same time period, as direct compliance with a greenhouse gas emission limit or emission reduction measure adopted by the state board pursuant to this division.

(l) "State board" means the State Air Resources Board.

(m) "Statewide greenhouse gas emissions" means the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported. Statewide emissions shall be expressed in tons of carbon dioxide equivalents.

(n) "Statewide greenhouse gas emissions limit" or "statewide emissions limit" means the maximum allowable level of statewide greenhouse gas emissions in 2020, as determined by the state board pursuant to Part 3 (commencing with Section 38850).

## CHAPTER 4. Role of State Board

38510. The State Air Resources Board is the state agency charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.

PART 2. MANDATORY GREENHOUSE GAS EMISSIONS REPORTING

38530. (a) On or before January 1, 2008, the state board shall adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program.

(b) The regulations shall do all of the following:

(1) Require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources beginning with the sources or categories of sources that contribute the most to statewide emissions.

(2) Account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. This requirement applies to all retail sellers of electricity, including load-serving entities as defined in subdivision (j) of Section 380 of the Public Utilities Code and local publicly owned electric utilities as defined in Section 9604 of the Public Utilities Code.

(3) Where appropriate and to the maximum extent feasible, incorporate the standards and protocols developed by the California Climate Action Registry, established pursuant to Chapter 6 (commencing with Section 42800) of Part 4 of Division 26. Entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas emission reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board.

(4) Ensure rigorous and consistent accounting of emissions, and provide reporting tools and formats to ensure collection of necessary data.

(5) Ensure that greenhouse gas emission sources maintain comprehensive records of all reported greenhouse gas emissions.

(c) The state board shall do both of the following:

(1) Periodically review and update its emission reporting requirements, as necessary.

(2) Review existing and proposed international, federal, and state greenhouse gas emission reporting programs and make reasonable efforts to promote consistency among the programs established pursuant to this part and other programs, and to streamline reporting requirements on greenhouse gas emission sources.

PART 3. STATEWIDE GREENHOUSE GAS EMISSIONS LIMIT

38550. By January 1, 2008, the state board shall, after one or more public workshops, with public notice, and an opportunity for all interested parties to comment, determine what the statewide greenhouse gas emissions level was in 1990, and approve in a public hearing, a statewide greenhouse gas emissions limit that is equivalent to that level, to be achieved by 2020. In order to ensure the most accurate determination feasible, the state board shall evaluate the best available scientific, technological, and economic information on greenhouse gas emissions to determine the 1990 level of greenhouse gas emissions.

38551. (a) The statewide greenhouse gas emissions limit shall remain in effect unless otherwise amended or repealed.

(b) It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020.

(c) The state board shall make recommendations to the Governor and the Legislature on how to continue reductions of greenhouse gas emissions beyond 2020.

PART 4. GREENHOUSE GAS EMISSIONS REDUCTIONS

38560. The state board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part.

38560.5. (a) On or before June 30, 2007, the state board shall publish and make available to the public a list of discrete early action greenhouse gas emission reduction measures that can be implemented prior to the measures and limits adopted pursuant to Section 38562.

(b) On or before January 1, 2010, the state board shall adopt regulations to implement the measures identified on the list published pursuant to subdivision (a).

(c) The regulations adopted by the state board pursuant to this section shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of sources, in furtherance of achieving the statewide greenhouse gas emissions limit.

(d) The regulations adopted pursuant to this section shall be enforceable no later than January 1, 2010.

38561. (a) On or before January 1, 2009, the state board shall prepare and approve a scoping plan, as that term is understood by the state board, for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020 under this division. The state board shall consult with all state agencies with jurisdiction over sources of greenhouse gases, including the Public Utilities Commission and the State Energy Resources Conservation and Development Commission, on all elements of its plan that pertain to energy related matters including, but not limited to, electrical generation, load based-standards or requirements, the provision of reliable and affordable electrical service, petroleum refining, and statewide fuel supplies to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner.

(b) The plan shall identify and make recommendations on direct emission reduction measures, alternative compliance mechanisms, market-based compliance mechanisms, and potential monetary and nonmonetary incentives for sources and categories of sources that the state board finds are necessary or desirable to facilitate the achievement of the maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020.

(c) In making the determinations required by subdivision (b), the state board shall consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union.

(d) The state board shall evaluate the total potential costs and total potential economic and noneconomic benefits of the plan for reducing greenhouse gases to California's economy, environment, and public health, using the best available economic models, emission estimation techniques, and other scientific methods.

(e) In developing its plan, the state board shall take into account the relative contribution of each source or source category to statewide greenhouse gas emissions, and the potential for adverse effects on small businesses, and shall recommend a de minimis threshold of greenhouse gas emissions below which emission reduction requirements will not apply.

(f) In developing its plan, the state board shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices.

(g) The state board shall conduct a series of public workshops to give interested parties an opportunity to comment on the plan. The state board shall conduct a portion of these workshops in regions of the state that have the most significant exposure to air pollutants, including, but not limited to, communities with minority populations, communities with low-income populations, or both.

(h) The state board shall update its plan for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions at least once every five years.

38562. (a) On or before January 1, 2011, the state board shall adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions in furtherance of achieving the statewide greenhouse gas emissions limit, to become operative beginning on January 1, 2012.

(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.

(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

(3) Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.

(4) Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and

maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

(5) Consider cost-effectiveness of these regulations.

(6) Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.

(7) Minimize the administrative burden of implementing and complying with these regulations.

(8) Minimize leakage.

(9) Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

(c) In furtherance of achieving the statewide greenhouse gas emissions limit, by January 1, 2011, the state board may adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020, inclusive, that the state board determines will achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions, in the aggregate, from those sources or categories of sources.

(d) Any regulation adopted by the state board pursuant to this part or Part 5 (commencing with Section 38570) shall ensure all of the following:

(1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board.

(2) For regulations pursuant to Part 5 (commencing with Section 38570), the reduction is in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur.

(3) If applicable, the greenhouse gas emission reduction occurs over the same time period and is equivalent in amount to any direct emission reduction required pursuant to this division.

(e) The state board shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section.

(f) The state board shall consult with the Public Utilities Commission in the development of the regulations as they affect electricity and natural gas providers in order to minimize duplicative or inconsistent regulatory requirements.

(g) After January 1, 2011, the state board may revise regulations adopted pursuant to this section and adopt additional regulations to further the provisions of this division.

38563. Nothing in this division restricts the state board from adopting greenhouse gas emission limits or emission reduction measures prior to January 1, 2011, imposing those limits or measures prior to January 1, 2012, or providing early reduction credit where appropriate.

38564. The state board shall consult with other states, and the federal government, and other nations to identify the most effective strategies and methods to reduce greenhouse gases, manage greenhouse gas control programs, and to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.

38565. The state board shall ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions.

PART 5. MARKET-BASED COMPLIANCE MECHANISMS

38570. (a) The state board may include in the regulations adopted pursuant to Section 38562 the use of market-based compliance mechanisms to comply with the regulations.

(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

(3) Maximize additional environmental and economic benefits for California, as appropriate.

(c) The state board shall adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits and mandatory emission reporting requirements to achieve compliance with their greenhouse gas emissions limits.

38571. The state board shall adopt methodologies for the quantification of voluntary greenhouse gas emission reductions. The state board shall adopt regulations to verify and enforce any voluntary greenhouse gas emission reductions that are authorized by the state board for use to comply with greenhouse gas emission limits established by the state board. The adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

38574. Nothing in this part or Part 4 (commencing with Section 38560) confers any authority on the state board to alter any programs administered by other state agencies for the reduction of greenhouse gas emissions.

PART 6. ENFORCEMENT

38580. (a) The state board shall monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board pursuant to this division.

(b) (1) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division may be enjoined pursuant to

Section 41513, and the violation is subject to those penalties set forth in Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(2) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division shall be deemed to result in an emission of an air contaminant for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(3) The state board may develop a method to convert a violation of any rule, regulation, order, emission limitation, or other emissions reduction measure adopted by the state board pursuant to this division into the number of days in violation, where appropriate, for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(c) Section 42407 and subdivision (i) of Section 42410 shall not apply to this part.

PART 7. Miscellaneous Provisions

38590. If the regulations adopted pursuant to Section 43018.5 do not remain in effect, the state board shall implement alternative regulations to control mobile sources of greenhouse gas emissions to achieve equivalent or greater reductions.

38591. (a) The state board, by July 1, 2007, shall convene an environmental justice advisory committee, of at least three members, to advise it in developing the scoping plan pursuant to Section 38561 and any other pertinent matter in implementing this division. The advisory committee shall be comprised of representatives from communities in the state with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations, or both.

(b) The state board shall appoint the advisory committee members from nominations received from environmental justice organizations and community groups.

(c) The state board shall provide reasonable per diem for attendance at advisory committee meetings by advisory committee members from nonprofit organizations.

(d) The state board shall appoint an Economic and Technology Advancement Advisory Committee to advise the state board on activities that will facilitate investment in and implementation of technological research and development opportunities, including, but not limited to, identifying new technologies, research, demonstration projects, funding opportunities, developing state, national, and international partnerships and technology transfer opportunities, and identifying and assessing research and advanced technology investment and incentive opportunities that will assist in the reduction of greenhouse gas emissions. The committee may also advise the state board on state, regional, national, and international economic and technological developments related to greenhouse gas emission reductions.

38592. (a) All state agencies shall consider and implement strategies to reduce their greenhouse gas emissions.

(b) Nothing in this division shall relieve any person, entity, or public agency of compliance with other applicable federal, state, or local laws or regulations, including state air and water quality requirements, and other requirements for protecting public health or the environment.

38593. (a) Nothing in this division affects the authority of the Public Utilities Commission.

(b) Nothing in this division affects the obligation of an electrical corporation to provide customers with safe and reliable electric service.

38594. Nothing in this division shall limit or expand the existing authority of any district, as defined in Section 39025.

38595. Nothing in this division shall preclude, prohibit, or restrict the construction of any new facility or the expansion of an existing facility subject to regulation under this division, if all applicable requirements are met and the facility is in compliance with regulations adopted pursuant to this division.

38596. The provisions of this division are severable. If any provision of this division or its application is held invalid, that invalidity shall not affect other provisions or applications that can be given effect without the invalid provision or application.

38597. 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.

38598. (a) Nothing in this division shall limit the existing authority of a state entity to adopt and implement greenhouse gas emissions reduction measures.

(b) Nothing in this division shall relieve any state entity of its legal obligations to comply with existing law or regulation.

38599. (a) In the event of extraordinary circumstances, catastrophic events, or threat of significant economic harm, the Governor may adjust the applicable deadlines for individual regulations, or for the state in the aggregate, to the earliest feasible date after that deadline.

(b) The adjustment period may not exceed one year unless the Governor makes an additional adjustment pursuant to subdivision (a).

(c) Nothing in this section affects the powers and duties established in the California Emergency Services Act (Chapter 7 (commencing with Section 8550) of Division 1 of Title 2 of the Government Code).

(d) The Governor shall, within 10 days of invoking subdivision (a), provide written notification to the Legislature of the action undertaken.

SEC. 2 No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.