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Greenhouse Gas Allowance Revenue
Allocation Methodologies for Emissions
Intensive and Trade Exposed Entities and
Small Businesses

Energy Division Staff Proposal

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Staff Proposal on Greenhouse Gas Allowance Revenue Allocation Methodologies for Emissions Intensive and Trade Exposed Entities and Small Businesses

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1. Introduction

1.1. Summary

This Energy Division staff proposal recommends methodologies to allocate greenhouse gas (“GHG”) allowance revenue to eligible industrial entities and small businesses. The purpose of this revenue allocation is to provide transition assistance so that industrial production and GHG emissions do not shift (i.e. “leak”) out of California, and small businesses have an opportunity to invest in measures that reduce their exposure to GHG costs in electricity rates. This proposal implements policies the California Public Utilities Commission (“CPUC” or “Commission”) enacted in Decision (D.)12-12-033 (the “Decision”), which determined how California investor-owned utilities (“IOUs” or “utilities”) would use revenue from the sale of GHG allowances that the California Air Resources Board (“ARB”) freely allocated to them as part of the Cap-and-Trade Program. D. 12-12-033 outlined specific policy objectives and established a broad framework that identifies what classes of electricity customers will receive this revenue. It also defined an implementation process through which the Commission would further develop specific formulas to allocate GHG allowance revenue to individual industrial entities and small businesses. This proposal is the result of the public process, including workshops and opportunities for public comment, initiated by the Decision, to resolve these outstanding implementation issues.

Appendices A and B to the Decision set forth preliminary formulas and a rationale for these formulas that could be used to determine what amount of GHG allowance revenue each qualifying industrial entity and small business should receive.¹ The formulas and implementation details we address herein build upon the appendices to the Decision and are substantially based on similar

¹ D.12-12-033, Findings of Fact (FOF) 84-101.

methodologies ARB developed to determine what amount of free allowances industrial entities are eligible to receive to address their direct emissions costs.² In developing these formulas, we followed a primary policy objective, supported by the Decision:³ mirror to the fullest extent practical the methodologies ARB uses to allocate allowances to entities that qualify for Industry Assistance. As a result, our recommendations maintain ARB's basic conceptual and methodological approach, where possible.

As required in the Decision,⁴ this proposal addresses the following topics:

1. Revenue allocation formulas for eligible industrial entities and small businesses;
2. Required input sources for the formulas;
3. Timing of all information and data exchanges that must occur;
4. Timing of the revenue distribution;
5. Method by which revenue should be returned to industrial entities; and
6. Alternatives to the requirement that industrial entities opt in to the Cap-and-Trade program if their emissions are less than 25,000 metric tons of carbon dioxide equivalent gas (MTCO_{2e}).

1.2. Procedural History

Under ARB's economy-wide GHG Cap-and-Trade program, the first phase of which began in 2012, the state's investor-owned electric utilities are annually granted a free allocation of GHG allowances that they are required to sell in ARB's quarterly allowance auctions. This mandatory consignment of allowances generates substantial revenue that, according to ARB's Cap-and-Trade

² See ARB's Initial Statement of Reasons (ISOR) Appendix J.

³ D.12-12-033, FOF 85.

⁴ Ibid, Conclusion of Law (COL) 68; Ordering Paragraph (OP) 25.

regulation, must be used exclusively for the benefit of customers of electric distribution utilities, consistent with the goals of Assembly Bill (“AB”) 32, the Global Warming Solutions Act of 2006.⁵ The Commission established a proceeding, Rulemaking (R.)11-03-012, to address the various policy questions that arose from ARB’s implementation of AB 32, among other issues. Track 1 of this proceeding, of which this proposal is a part, addresses how GHG allowance revenue should be allocated in accord with direction provided in ARB’s Cap-and-Trade regulation, as well as with parameters established by the Legislature in Senate Bill (“SB”) 1018, which Governor Brown signed on June 27, 2012.

Senate Bill 1018 added § 748.5 to the Public Utilities Code, which among other things required the Commission to provide a direct return of allowance revenue to residential, “small business,” and “emissions-intensive and trade-exposed” entities. For the purposes of GHG allowance revenue allocation, D.12-12-033 defined small businesses as those non-residential electricity customers with a monthly electricity demand that does not exceed 20 kilowatts in more than three months within a twelve-month period.⁶ It also interpreted “emissions-intensive and trade-exposed” (“EITE”) to mean those entities in industrial sectors that qualify for Industry Assistance under ARB’s Cap-and-Trade regulation, regardless of the amount of emissions produced. These industries are explicitly listed by North American Industry Classification System (“NAICS”) Code in ARB’s Cap-and-Trade regulation.⁷

In addition, the Decision found that “entities with emissions levels less than 25,000 metric tons of carbon dioxide equivalent gas (MTCO_{2e}) that operate in sectors eligible for Industry Assistance must voluntarily opt in to the Cap-and-

⁵ 17 CCR § 95892(d)

⁶ D.12-12-033, COL 11.

⁷ See D.12-12-033 FOF 63, COL 2 and 13. See also 17 CCR § 95870 et seq. and industries listed by NAICS Code in *Table 8-1: Industry Assistance*

Trade program, unless another suitable method can be found to accurately obtain the necessary information to calculate revenue returns for these customers.”⁸ The Decision allowed staff and Parties to evaluate, in this current implementation phase, whether there are effective ways to allow these particular entities to receive an allocation of allowance revenue without opting in to the Cap-and-Trade program.⁹

Though D.12-12-033 defined a list of industries that qualify as EITE, and it specified a preference that the methodologies used to allocate revenue to eligible entities should be based as closely as practicable on ARB’s methodologies for allocating allowances for Industrial Assistance, it deferred a final decision about these methodologies to the current implementation phase of the Decision.¹⁰ Accordingly, the Decision directed Energy Division to convene a workshop within 60 days of the issuance of the Decision to evaluate the allocation methodologies set forth in Appendices A and B; identify required data input sources for these methodologies; identify timing of information and data exchanges that must occur to calculate the revenue return; evaluate the timing and form of the GHG revenue distribution; and explore alternative options to the requirement to opt in to the Cap-and-Trade program for EITE entities with emissions less than 25,000 MTCO_{2e}.¹¹

On January 23, 2013, Administrative Law Judge (“ALJ”) Semcer issued a ruling announcing a technical workshop and soliciting pre-workshop comments by Parties on the methodologies proposed in Appendices A and B to the Decision. In accord with the Decision and subsequent ALJ ruling, Staff conducted a technical workshop on February 14 and 15, 2013, to discuss these

⁸ D.12-12-033, FOF 58.

⁹ *Ibid*, p. 151; FOF 58; COL 14; COL 68; OP 6.

¹⁰ *Ibid*, FOF 85 and 86.

¹¹ *Ibid*, OP 25.

appendixes and other implementation issues relevant to the allocation of revenue to industrial entities and small businesses. The January ruling also directed Energy Division to serve a draft staff proposal on parties to R.11-03-012 by April 15, 2013. In a subsequent ruling dated March 24, 2013, ALJ Semcer extended this deadline until May 15, 2013.

On June 7, 2013, Energy Division held a public workshop to discuss a draft of this staff proposal, after which ALJ Semcer invited Parties to submit informal comments to Energy Division to address topics raised during the workshop. Via email ruling on June 12, 2013, ALJ Semcer revised the procedural schedule to incorporate this staff proposal into the record on July 10, 2013, with Parties invited to file formal comments on this final proposal by July 24, 2013.

1.3. Overview of ARB's Industrial Assistance

1.3.1. Eligibility

ARB provides Industrial Assistance to certain industrial sectors covered by the Cap-and-Trade program to address leakage risk and to provide transition assistance. This assistance occurs in the form of an allocation of free allowances to cover a percentage of an industrial entity's direct emissions – emissions from on-site activities, as well as those associated with heat imported from offsite.¹²

The introduction of “an environmental regulation in one jurisdiction can cause production costs and prices in that jurisdiction to increase relative to costs in jurisdictions that do not introduce comparable regulations. This can precipitate a shift in demand away from goods produced in the implementing jurisdiction toward goods produced elsewhere. As a result, the reduction in production and emissions in the implementing jurisdiction is offset by increased production and emissions elsewhere. This offsetting increase in emissions is

¹² ARB Initial Statement of Reasons (ISOR) Appendix J, p. 32

called emissions leakage,”¹³ and the shift in production out of the implementing jurisdiction is considered economic leakage. To prevent leakage, ARB provided a free allocation of allowances to industrial sectors at risk of leakage, which has the effect of reducing an industrial entity’s cost of complying with the Cap-and-Trade program while maintaining the integrity of the GHG emissions cap and preserving incentives for facilities to operate efficiently and to reduce emissions. This free allocation of allowances also provides transition assistance: by reducing the near-term cost of compliance with the Cap-and-Trade program, it preserves an entity’s ability to invest in measures (e.g. energy efficiency; fuel switching) that reduce its exposure to GHG costs, thus allowing the entity to smoothly transition to the current paradigm of carbon pricing.

ARB evaluated which industrial sectors qualify for Industry Assistance by conducting a leakage analysis that resulted in an assignment of high, medium or low leakage risk to specific industrial sectors.¹⁴ This analysis evaluated the emissions intensity and the trade share of certain manufacturing and oil and gas extraction industrial sectors. Though wide-ranging, the scope of this study was limited to industrial sectors in which at least one entity had a direct compliance obligation under the Cap-and-Trade program. ARB therefore studied industries that had high levels of direct emissions (i.e. those associated with on-site fuel combustion and steam purchases). As D.12-12-033 concluded, however, there may be industries with relatively low levels of direct emissions but high levels of electricity purchases, and therefore a high exposure to indirect GHG emissions costs experienced indirectly through electricity rates.¹⁵

During the first compliance period of the Cap-and-Trade program, industrial facilities that have direct emissions below 25,000 MTCO_{2e} will not

¹³ ARB ISOR Appendix J, p. 18; D.12-12-033, p. 17.

¹⁴ See ARB ISOR, Appendix K.

¹⁵ D.12-12-033, p. 86.

pose a leakage risk as a result of their *direct* emissions – that is, they will not have any direct Cap-and-Trade compliance costs unless they voluntarily opt-in to the Cap-and-Trade program. However, with the Commission’s decision that electricity rates for commercial and industrial customers should include a carbon price signal, industries not included in ARB’s assessment of leakage risk will experience an indirect GHG cost through their electricity rates that is not offset by an allocation of revenue. This dynamic therefore expands the potential range of manufacturing and related industries that the Commission may want to analyze for potential leakage risk.

Though ARB’s free allocation of allowances only covers an industry’s *direct* emissions, as we describe below, it is important to note that ARB’s analysis of industrial leakage risk took into consideration an industry’s *total* emissions – including both direct and indirect emissions.¹⁶ As a result, ARB’s assignment of leakage risk – high, medium, or low, for each industry – is still relevant in the context of D.12-12-033, because that assessment of leakage risk included indirect emissions associated with electricity purchases.

1.3.2. Product-Based Allocation Methodology

ARB’s preferred method of allocating allowances to industrial entities is via an emissions intensity product benchmark. Benchmarking allows ARB to compare the relative GHG emissions intensity of a given industrial entity to a common standard. It rewards facilities that have taken early action to reduce emissions and ensures that industries have a strong incentive to produce products in the most GHG-efficient way possible.¹⁷

Under a product-based benchmark approach, ARB allocates allowances to industrial entities as a function of the industrial sector-wide GHG emissions

¹⁶ ARB ISOR Appendix K, p. 10.

¹⁷ ARB ISOR Appendix J, p. 11, p. 26.

released per unit of product output. ARB’s GHG emissions intensity benchmarks are specific to each industrial sector and are calculated based on total sector-wide emissions divided by total product output during a given historical period, taking into account only those entities that have a compliance obligation. Product-based benchmarks are calculated once at the outset of the program and are not updated over time. They are listed explicitly for each industry in Table 9-1 of ARB’s Cap and Trade Regulation.

Though industry emissions intensity benchmarks remain fixed, an individual facility’s annual allocation of allowances will vary depending on the facility’s annual product output. This approach ensures that industrial facilities are compensated in proportion to actual emissions produced, which may vary significantly year by year with variations in product output. Product-based allocation also ensures that a facility that is more efficient than the benchmark will have an economic advantage over a facility that is less efficient than the benchmark. Inefficient facilities will have to acquire a greater amount of additional allowances beyond those freely allocated – either at auction or in a secondary market for allowances.¹⁸

Below we present the general formula and variables used to allocate *allowances* under ARB’s product-based methodology. In Section 2 we discuss each of these variables at greater length in the context of the Commission’s decision to allocate *revenue* to address indirect costs from electricity purchases.

Simplified general formula for a product-based allocation of *allowances*:

$$Allocation = O \times B \times AF \times C$$

Where:

“O” is the total production from a given industrial activity subject to the product-based benchmark.

¹⁸ ARB ISOR Appendix J, p. 21.

“B” is the emissions intensity benchmark per unit of product output for the applicable sector. Benchmark units are in terms of allowances per quantity of product output. This amount is calculated for each activity defined in Table 9-1 of ARB’s Cap-and-Trade regulation. It is calculated by summing, across all entities in a given industrial sector, direct emissions and indirect emissions from steam purchases, less direct emissions associated with sold electricity and steam, and then dividing this amount of emissions by total production for the industrial sector. The benchmark formula is:

$$0.9 * [\text{Direct Emissions} + (\text{Steam Purchased} - \text{Steam Sold}) * \text{EF}_{\text{Steam}} - \text{Electricity Sold} * \text{EF}_{\text{Electricity}}] / \text{Production}$$

Where:

0.9 is a benchmark stringency factor chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities within each industrial activity. For sectors in which there was only one covered entity or in which no covered entity was at least as efficient as the benchmark, the benchmark is instead set based on the “best-in-class” value (i.e. the emissions of the most GHG-efficient California facility).

“Direct Emissions” is the total direct emissions, over an historical period, for the industrial sector for which the benchmark “B” is being calculated. Direct emissions are those that result from process emissions (where applicable) and the combustion of fossil fuels onsite.

“Steam Purchased” is the total steam purchased by the sector for which the benchmark “B” is being calculated over a historical period, in MMBTU.

“Steam Sold” is the total steam sold by the sector for which the benchmark “B” is being calculated over a historical period, in MMBTU.

“EF” is a benchmark for emissions from steam or electricity. ARB used an emissions factor for steam of .06244 tonne CO_{2e}/MMBTU_{steam}, which is consistent with a boiler utilizing natural gas and operating at 85% efficiency, and .431 tonne CO_{2e}/MWH for electricity.

“Electricity Sold” is the total electricity sold by the sector for which the benchmark “B” is being calculated over a historical period, in MWH.

“Production” is the total output for the industrial activity for which the benchmark is being calculated over a historical period.

“AF” is the “assistance factor,” which is the percent of the emissions benchmark (described below) that will be provided in an allocation. The assistance factor ranges from 30% to 100%, depending on the sector’s leakage risk classification (high: 100% for all compliance periods; medium: 100%, 75%, and 50% for the first, second, and third compliance periods, respectively; and low: 100%, 50%, 30%). The specific percentage is tied to ARB’s determination of a sector’s leakage risk and the year in which the allocation is being sought. The specific Assistance Factor that applies to a given sector each year can be found in Table 8-1 of ARB’s Cap-and-Trade regulation.

“C” is the Cap Adjustment Factor applied to the allocation calculation to scale the allocation consistent with the decline in the overall GHG cap. This factor will depend on the year in which an allocation is being provided. The schedule for the Cap Adjustment Factor can be found in Table 9-2 in the ARB’s cap-and-trade regulation.

In general, when calculating product-based benchmarks, ARB relied on a historical period of 2008-2010, with some variability in instances when different data were necessary to establish a baseline benchmark.

1.3.3. Energy-Based Allocation Methodology

ARB uses an energy-based allocation methodology for sectors in which a product-based approach has not yet been developed or is not technically feasible – for example, when there is too much heterogeneity among products made by a single sector. Some sectors have relatively simple and uniform products and processes (e.g. cement), whereas others have a wide range of products (e.g. the food manufacturing sector) that make it difficult to calculate a uniform benchmark for the sector. Though certain sectors do not currently have a product-based benchmark, ARB staff has the ability to continue working with sectors to define a product-based benchmark and to transition a sector from the energy-based allocation to a product-based allocation. In the event that ARB transitions a sector from an energy-based to a product-based allocation, we recommend in Section 3 below that the Commission also adjust the allocation for such sectors to a product-based methodology.

Under its energy-based allocation methodology, ARB calculates a benchmark based on the historical annual arithmetic mean emissions from a given covered entity. Whereas a product-based benchmark applies equally to all entities in a specific industrial sector, ARB’s energy-based benchmarks are facility-specific. Energy-based benchmarks are also not tied to a facility’s annual product output, nor are they tied to variations in a facility’s ongoing energy use. ARB characterizes the use of an energy-based benchmark as a “fallback” approach.¹⁹

ARB’s energy-based allocation relies on the following formula:

$$A_t = (S_{consumed} \times B_{steam} + F_{consumed} \times B_{fuel} - e_{sold} \times B_{electricity}) \times AF_{a,t} \times c_{a,t}$$

Where:

¹⁹ ARB ISOR Appendix J, p. 50.

“ A_t ” is the amount of GHG allowances directly allocated to the operator of an industrial facility with an energy-based allocation from budget year “ t ”;

“ S_{consumed} ” is the historical baseline annual arithmetic mean amount of steam consumed, measured in MMBtu, at the industrial covered entity for any industrial process, including heating or cooling applications. This value shall exclude any steam used to produce electricity. This value shall exclude steam produced from an onsite cogeneration unit;

“ B_{Steam} ” is the emissions efficiency benchmark per unit of steam, 0.06244 California GHG Allowances/MMBtu Steam;

“ F_{Consumed} ” is the historical baseline annual arithmetic mean amount of energy produced due to fuel combustion at a given covered entity, measured in MMBtus. ARB’s Executive Officer shall calculate this value based on measured higher heating values or the default higher heating value of the applicable fuel in Table C-1 of subpart C, title 40, Code of Federal Regulations, Part 98 (October 30, 2009). This value shall include any energy from fuel combusted in an onsite electricity generation or cogeneration unit. This value shall exclude energy used to generate the steam accounted for in the “ S_{Consumed} ” term;

“ B_{Fuel} ” is the emissions efficiency benchmark per unit of energy from fuel combustion – 0.05307 California GHG Allowances/MMBtu;

“ e_{Sold} ” is the historical baseline annual arithmetic mean amount of electricity sold or provided for off-site use, measured in MWh;

“ $B_{\text{Electricity}}$ ” is the emissions efficiency benchmark per unit of electricity sold or provided to off-site end users, 0.431 California GHG Allowances/MWh;

“ $AF_{a,t}$ ” is Assistance Factor for budget year “ t ” assigned to each activity “ a ” in Table 8-1 of ARB’s Cap-and-Trade regulation. This factor represents the percent of the energy benchmark that will be provided in an allocation, ranging from 30% to 100% in a given budget year. The specific percentage is determined based on ARB

determinations regarding the level of emissions intensity and trade exposure an entity is subject to and the budget year from which the allocation is being drawn.

“ C_t ” is the Cap Adjustment Factor for budget year “t” assigned to each activity “a” in Table 9-2 of ARB’s Cap-and-Trade regulation, and is applied to the allocation calculation to scale the allocation consistent with the decline in the overall GHG cap.

When calculating the energy-based benchmark for each industrial entity, ARB relied on an historical period of 2008-2010, with some variability in instances when different data were necessary to establish a baseline benchmark.

1.3.4. Refinery Allocation

ARB’s refinery allocation methodology uses a two-tiered approach to allocate revenue to individual refineries. ARB first allocates allowances to the refinery sector as a whole by using the product-based benchmarking methodology. This sector-wide allocation varies to reflect changes in total refinery output from year to year. After allocating allowances to the refinery sector, ARB apportions allowances to each refinery based on the complexity of the refinery: for simple refineries, ARB allocates allowances based on a simple-barrel product-benchmark; and for complex refineries, which comprise approximately 90% of refinery capacity in California, ARB allocates allowances based on the relative efficiency of each refinery. Owing to the complexity of the refinery allocation methodology, we defer a lengthier treatment of the rationale and formulas associated with this methodology to Section 4 below.

ARB’s Cap-and-Trade regulation currently envisions that the refinery allocation methodology as defined at present will apply only to the first compliance period, and that ARB will transition to a carbon dioxide weighted tonne (“CWT”) approach after the first compliance period. ARB is currently

evaluating alternatives to the CWT approach, and staff anticipates that ARB will complete this evaluation and any potential regulation changes to the refinery methodology before the end of 2013. As a result of this uncertainty and both the complexity and time-intensiveness of developing complementary methodologies to address indirect emissions, staff has deferred proposing allocation formulas under the CWT approach. Once we have more regulatory certainty from ARB, the Commission will need to revisit its own refinery allocation methodology to ensure that the Commission's methodology continues to align with ARB's during the second and third compliance periods.

1.4. Policy Objectives

ARB's allocation methodologies were established and vetted in a lengthy public process with the participation of affected industries and interested parties. Deviations from ARB's methodologies could result in inequities and perverse outcomes, if, for example, they lead to over or under-compensation of indirect emissions relative to direct emissions.

The Commission indicated a preference to closely mirror ARB's allocation methodologies, making changes as necessary to account for the fact that the Commission will allocate revenue, rather than allowances, and that benchmarks need to reflect indirect emissions from electricity purchases, rather than direct emissions. Furthermore, by developing methodologies that closely parallel ARB's, the Commission will minimize transition difficulties for industries and regulators in the event that ARB decides at a later date to revise its benchmarking methodologies to address indirect emissions from electricity purchases, as well as direct emissions.

As a result, Staff recommends as a guiding principle that the Commission mirror ARB's allocation methodologies as closely as possible, making exceptions only when:

- ARB's methodology presents unnecessary or administratively unworkable complications when applied to emissions from electricity purchases;
- Necessary data are unavailable;
- ARB's formulas result in perverse outcomes when applied to emissions from electricity purchases; or
- Policy questions arise that ARB did not address in the scope of its regulation.

Additionally, given the complexity of these allocation methodologies and the data analysis likely required to implement the allocation, we propose that it is reasonable for the Commission to prioritize administrative simplicity when presented with competing policy choices that have generally commensurate public benefits.

2. Product-Based Allocation Methodology

2.1. Proposed Formula

Staff proposes that the Commission should use a product-based allocation methodology for all sectors that receive Industry Assistance from ARB according to a product output-based allocation methodology. The industrial sectors that should receive a product-based allocation of revenue from the Commission are those represented by NAICS Code in Table 9-1 of ARB's Cap-and-Trade regulation, as may be modified over time. If ARB expands the list of industrial sectors that receive a product-based allocation, the Commission should likewise develop a commensurate product-based benchmark for the electricity purchases of these new sectors, according to the methodology proposed below.

Some modifications to ARB’s product-based allocation and benchmark formulas are necessary to make them applicable to indirect emissions costs. These changes affect the benchmark variable B , which must be modified to address emissions from electricity purchases; the inclusion of a dollar conversion factor, D , to convert allowances into dollars; and a true-up term to account for timing disparities between the availability of verified product output data for each year and the month when the Commission grants revenue to eligible entities.

2.1.1. Generic Formula without a True-Up

Appendix A to D.12-12-033 proposes the following general product-based allocation formula, which we have modified slightly for accuracy and clarity.²⁰ In the subsequent formula, and throughout this document, the year “ t ” refers to the budget year for which the Commission will be allocating revenue. For example, if the Commission is allocating revenue to address GHG costs experienced through electricity purchases in calendar year 2013, “Allocation _{t} ” in this case would represent the amount of GHG allowance revenue directly allocated to the operator of an eligible industrial facility for Cap-and-Trade budget year 2013.

Equation 1. General Product-Based Allocation Formula

$$Allocation_{b,t} = \sum_{a=1}^n (O_{a,initial} \times B_{EP,a} \times AF_{a,t} \times C_{a,t} \times D_t)$$

Where:

“ a ” is an eligible industrial activity defined in Table 9-1 of ARB’s Cap and Trade regulation

²⁰A summation term was added to indicate that the allocation to a single industrial facility may include an allocation for multiple eligible industrial activities (i.e. products) listed in Table 9-1 of ARB’s Cap-and-Trade regulation. For example, a single facility may produce both hot rolled steel and cold rolled steel. Both of these products have different benchmark variables and assistance factors.

“b” is an individual industrial facility that operates in industrial activity “a.”

“ $O_{a, \text{initial}}$ ” is the total production output from a given industrial activity at a given facility subject to the product-based benchmark. In Appendix A to D.12-12-033, this “initial” year was defined as year “t-1,” in which case an allocation to address 2013 costs would be based on verified product output data from 2012. As a default approach, Staff recommends that this term should represent verified product output for year “t-1.” We address the data source for this output variable and the potential need to true-up this variable in the subsections immediately below, as well as Section 2.5.

“ $B_{EP,a}$ ” is the indirect emissions benchmark for industrial activity “a” in terms of MTCO_{2e} of emissions from electricity purchases per unit output for the applicable sector. The emissions benchmark for electricity purchases is calculated by summing, across all entities in industrial sector “a”, indirect emissions from electricity purchases, and then dividing this amount by total production output for the industrial activity. The exact formula used to calculate this benchmark for each industrial activity is discussed below in Section 2.3.

“ $AF_{a,t}$ ” is the “assistance factor” for budget year “t” assigned to a given industrial activity “a.” Assistance factors for each industrial activity are specified in Table 8-1 of ARB’s Cap-and-Trade regulation. The assistance factor is the percent of the emissions benchmark (described in Section 2.2 below) that will be provided in an allocation, ranging from 100% to 30%. The specific percentage is tied to ARB’s determination of an industrial sector’s leakage risk and the year for which the allocation is being sought.

“ $C_{a,t}$ ” is the cap adjustment factor for budget year “t” assigned to each industrial activity “a”. The cap adjustment factor represents the decline in the overall GHG cap. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB’s Cap-and-Trade regulation. We address the cap adjustment factor in greater length in Section 2.4 below.

“ D_t ” is the Dollar Conversion Factor calculated based on the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided. This variable is addressed in more detail in Section 2.6 below.

The timing of the revenue return depends on the annual availability of product output data, “ O ”, and the completion of ARB’s fourth quarter GHG allowance auction, which is necessary to calculate “ D ”, as proposed above. All other allocation variables are either fixed by the Cap-and-Trade regulation (i.e. assistance factors and the cap adjustment factor) or will be calculated once and will not be updated over the length of the Cap-and-Trade program (i.e. the benchmark variable).

Appendix A to D.12-12-033 proposes using a product output variable “ O_{t-1} ,” rather than “ O_{initial} .” As we discuss in Section 2.5, ARB collects annual product output data “ O ” from each covered entity via its Mandatory Reporting of GHG Emissions Regulation (MRR), which Staff proposes should also be the data source used for the product output variable in the Commission’s revenue allocation methodologies. Covered entities are required to report the last calendar year’s product output data to ARB in April of each year and to provide verified data by September of the same year. Therefore, as of September 2013, the most current verified product output data available for use in the Commission’s allocation methodologies will represent 2012 calendar year production output.

It is conceivable that industrial output and GHG allowance prices may fluctuate significantly from year to year, potentially resulting in an over or under-collection that needs to be corrected in subsequent years. This need for a correction or “true-up” is caused by the timing lag between when industries

experience GHG costs (starting at the beginning of each calendar year, and accruing over time), and the availability of both verified product output data and weighted average allowances prices in a year (toward the end of each calendar year).

ARB includes a true-up term in its product-based allocation – a feature that was missing from the Commission’s preliminary methodology outlined in Appendix A to D.12-12-033. Rather than delay its allowance allocation until verified product data are available for a given budget year, ARB allocates allowances at the beginning of a budget year, based on the most recent year of product output data available, and then trues-up this allocation in later years to reflect the difference between actual product output data, once it is known, and the product output data used in the original allocation.

The following subsections discuss how the Commission could modify ARB’s true-up term depending on whether the Commission prefers to allocate revenue after costs have been incurred (i.e. in arrears) or to allocate revenue in advance of costs being incurred.

2.1.2. Allocation in Arrears with a True-Up

The methodologies proposed in D.12-12-033 imply that revenue would be allocated in arrears – timing would be dependent on the availability of both product output from year “t-1” and on the completion of ARB’s fourth-quarter allowance auction in November of year “t.” For example, the revenue allocation to address GHG costs that a facility incurs in 2013 would rely on verified product output data for calendar year 2012 (which industries are required to report to ARB in September 2013), and on the weighted average market clearing price of allowances sold at auction in 2013, which would be known in November 2013. Therefore, after ARB’s fourth auction in November 2013, the Commission

will have all data necessary to allocate allowances in arrears, based on verified 2012 product output data. The disadvantage of this approach is that industrial entities would carry a year's worth of GHG costs in electricity rates all throughout 2013 before receiving an offsetting amount of revenue in 2014.

Under an allocation methodology that grants revenue in arrears, the following true-up term should be added to Equation 1 above to account for actual product output data once it is known. The first true-up would occur in budget year $t=2014$, and the last true-up would occur in the year immediately following the last budget year of the Cap-and-Trade program (the last budget year is currently 2020).

Equation 2. True-Up Term for an Allocation in Arrears, Added to Equation 1

$$Trueup_{b,t} = \sum_{a=1}^n (O_{a,trueup} \times B_{EP,a} \times AF_{a,t-1} \times C_{a,t-1} \times D_{t-1})$$

Where:

“ t ” is the budget year to which the true-up is added to address emissions that occurred during year $t-1$.

“ $O_{a,trueup}$ ” adjusts for any product output not properly accounted for in prior allocations. Under an approach that allocates revenue in arrears, Staff recommends that this term should be the difference between verified product output data in year “ $t-1$ ” and verified product output data for year “ $t-2$.” Therefore $O_{a,trueup} = O_{a,t-1} - O_{a,t-2}$.

As an example of how this true-up would work in practice, for budget year $t=2014$ the true-up term would correct the 2013 allocation and be as follows:

$$Trueup_{b,2014} = \sum_{a=1}^n ((O_{a,2013} - O_{a,2012}) \times B_{EP,a} \times AF_{a,2013} \times C_{a,2013} \times D_{2013})$$

If an industrial entity's product output in 2013 exceeded product output in 2012, the entity would receive an additional allocation of revenue in 2014. Conversely, if 2013 production output were less than output in 2012, the difference would be subtracted from the 2014 allocation.

The benefit of including a true-up term is that it ensures that a facility receives an accurate amount of allowances revenue. Though a true-up term complicates the allocation formula, from an administrative standpoint the inclusion of a true-up should add a negligible amount of quantitative or other implementation work for Staff.

2.1.3. Advance Allocation with a True-Up

In their written pre-workshop comments about the methodologies proposed in Appendix A to D.12-12-033, the Large Users recommended that the Commission should allocate revenue in advance of costs incurred.²¹ A prospective or advance allocation of revenue would mirror ARB's own approach, which is to allocate allowances at the beginning of each budget year based on the most recent product output data available. We discuss the merits of this approach in Section 2.1.4 below, but in this section we address the mechanics of how a prospective allocation could be implemented.

To restate the obvious, ARB allocates allowances, but the Commission must allocate revenue. In order to allocate revenue in advance of costs being incurred in a program year, the Commission would either need to make an assumption about what the price of allowances will be for the coming budget year, or it could use the most recent weighted average allowance auction price available, and then develop a true-up term that accounts for an updated dollar conversion factor as well as updated product output data.

²¹ Large Users' Pre-Workshop Statement, p. 7-8; Attachment A-1.

Since it could be potentially problematic for the Commission to issue a GHG allowance price forecast, we propose that it is more reasonable to implement a prospective allocation for budget year “t” costs by using the most recent year’s dollar conversion factor (i.e. the sales-weighted average market clearing price of allowances of vintage “t-1” sold during year “t-1” auctions).

A prospective allocation raises an additional complexity. ARB’s first quarterly allowance auction occurs in February of each year, and verified product output data for the previous year are unavailable until September. If the Commission were to mirror ARB and offer a prospective allocation in the first quarter of budget year “t,” the Commission would need to rely on verified product output data from two years prior (i.e. year “t-2” product output data). True-ups would therefore occur on a two-year time lag.

Equation 3 and Equation 4 below illustrate, respectively, the general formula and true-up term for a prospective product-based revenue allocation.

Equation 3. Product-Based Allocation Formula for Prospective Allocation

$$Allocation_{b,t} = \sum_{a=1}^n (O_{a,t-2} \times B_{EP,a} \times AF_{a,t} \times C_{a,t} \times D_{t-1})$$

Equation 4. True-Up Term for a Prospective Allocation, Added to Equation 3

$$Trueup_{b,t} = \sum_{a=1}^n (AF_{a,t-2} \times B_{EP,a} \times C_{a,t-2} \times [(O_{a,t-2} \times D_{t-2}) - (O_{a,t-4} \times D_{t-3})])$$

As an example of how this true-up would work in practice, the initial allocation for costs experienced in budget year 2013 will need to be trued-up in the budget year 2015 allocation. For budget year t=2015, the true-up term would be as follows:

$$Trueup_{b,2015} = \sum_{a=1}^n (AF_{a,2013} \times B_{EP,a} \times C_{a,2013} \times) [(O_{a,2013} \times D_{2013}) - (O_{a,2011} \times D_{2012})]$$

The true-up term for the 2013 allocation is a special case, since it was procedurally impossible for the utilities to allocate revenue in the beginning of 2013, before allocation formulas had been developed. As a result, this true-up will only require adjustments to the product output variable. The specific equation for this case is outlined in Appendix A.

2.1.4. Recommended Approach

Staff believes that from the standpoint of administrative simplicity, each of the product-based allocation methodologies proposed above are equivalent – they would require the same amount of staff time to implement. The relative complexities between the three approaches are manifest solely in the allocation formulas themselves.

Over time, a product-based allocation methodology that does not make use of a true-up would result in the most inaccurate allocation of revenue, potentially resulting in significant over or under-allocations of revenue to individual industrial entities. We therefore do not recommend that the Commission use the exact product-based allocation formula included in Appendix A to D.12-12-033, which lacks a true-up term.

Staff concludes that an allocation in arrears with a true-up (Equation 1 and Equation 2) and a prospective allocation with a true-up (Equation 3 and Equation 4) are both satisfactory approaches that would fulfill the intent and requirements of D.12-12-033. However, Staff recommends that the Commission adopt the prospective product-based allocation methodology expressed in Equation 3 and Equation 4. The effect of this approach, compared to providing an allocation in arrears, is to provide industrial entities with an additional level of transition

assistance without any apparent detriment to other classes of ratepayers or threats to the integrity of the Cap-and-Trade program. The Commission indicated a preference for an allocation that occurs “after a given Cap-and-Trade program budget year has passed;” however this preference was based on a desire for allocations to be “based on actual market prices, rather than projections.”²² Since the prospective allocation formulas stated in Equation 3 and Equation 4 are based on the weighted average clearing price of the most recent year’s allowance auctions, Staff believes that a prospective allocation addresses the Commission’s preference, which we interpret as discouraging the use of forecasted allowance prices.

Despite Staff’s recommendation to use a prospective allocation, we find that an allocation in arrears is also a satisfactory approach. We are not persuaded, at present, that the burden of carrying a year of GHG costs in electricity rates poses a significant financial hardship for the size and type of industries covered by the Cap-and-Trade program that receive a product-based allocation, especially since these industrial entities know full well that, in a worst case scenario, GHG costs will be offset by an allocation of allowance revenue in the subsequent year. However, we concede that there is potential, albeit small, for a year’s worth of GHG costs to contribute to an industry’s leakage risk. More importantly, we believe there is value in providing transition assistance to encourage these industries to invest in measures to reduce their overall exposure to GHG costs.

In total, a prospective allocation and an allocation in arrears would result in the same amount of revenue being returned; however, a prospective allocation would allocate revenue in a timelier manner, and it would benefit eligible

²² D.12-12-033, FOF 92.

industrial entities without any known negative impacts on ratepayers or the Cap-and-Trade program.

2.2. Assistance Factors

Staff recommends that the assistance factors used in the product-based allocation methodology, as well as in the energy-based and refinery allocation methodologies, should exactly parallel the assistance factors for each industrial activity outlined in Table 8-1 of ARB's Cap-and-Trade regulation. If ARB revises these assistance factors in the future, the Commission's allocation methodologies should automatically reflect these changes to ARB's regulation without the need for subsequent procedural action by the Commission.

ARB established these assistance factors based on a leakage risk analysis for each of these industrial activities.²³ This analysis evaluated leakage risk as a result of an industry's total emissions, including direct emissions and indirect emissions from electricity purchases. Even though ARB does not allocate allowances to address GHG costs in electricity rates, its leakage study was conducted in a manner that assumed, and modeled, conditions in which electricity rates reflect a GHG costs. As a result, Staff sees no compelling reason why the assistance factors developed by ARB should not also be relevant in the context of the Commission's revenue allocation to address GHG costs in electricity rates.

In its Initial Statement of Reasons (ISOR), ARB explains the rationale for setting declining assistance factors. "Assistance levels need to be high at the outset of the program to avoid sudden or undue impact to the current structure of the economy and to address both transition issues and emissions leakage...Assistance in early years will alleviate any short-term economic

²³ See ARB Initial Statement of Reasons, Appendix K.

impacts and will help promote a smooth transition to a low-carbon economy. Assistance rates will decline as the covered entities gradually adjust to the carbon price and adopt energy- and carbon-saving strategies.”²⁴

2.3. Benchmark Variable

“Greenhouse gas benchmarks are metrics that enable the comparison of GHG emissions performance across similar industrial facilities.”²⁵ The product benchmark variable is a key part of ARB’s allocation methodology to determine the annual amount of free allowances allocated to each eligible industrial facility. It allows each facility’s allocation to vary with the facility’s annual product output, thus preserving the facility’s incentive to maintain production in California, and it ensures that GHG-efficient facilities are at an advantage relative to their less efficient peers.

ARB’s product-based benchmarks are a measure of sector-wide emissions intensity: metric tons of carbon dioxide equivalent gas per unit of industrial output for each industry. Benchmarks are fixed – ARB calculated them once at the outset of the program and has no apparent intention to update them – and they are calculated as an average across all facilities in an industrial sector. Since ARB’s methodology results in a sector-wide average, individual facilities that are highly emissive will tend to increase the benchmark, while those that operate more efficiently will tend to lower the benchmark. If two facilities in the same industry have the same product output in a given year, the facility that operates more efficiently will therefore be at an advantage – each facility will receive the same amount of allowances and allowance revenue, but the efficient facility will receive more compensation per unit of emissions than its less efficient competitors, which will need to procure additional allowances at market.

²⁴ ARB ISOR Appendix J, p. 19.

²⁵ ARB ISOR Appendix J, p. 21.

2.3.1. Definition of Benchmark

ARB's benchmark methodology takes into consideration all direct emissions and emissions associated with steam purchases, less any emissions associated with steam sales and electricity exports. As a complement to ARB's benchmark, the Commission's benchmark variable, B_{EP} , must take into account electricity purchases, the sole energy source omitted from ARB's benchmarks.

The Commission has a choice to develop a product benchmark that represents either electricity intensity or the electricity emissions intensity of product output. An electricity intensity benchmark would reflect an industrial sector's average electricity purchases per unit of product output (MWh/output). Such a benchmark would capture the relative efficiency of each facility's operations, but it would exclude the emissions intensity of a facility's electricity sources. Alternatively, an electricity emissions intensity benchmark would capture an industrial sector's electricity intensity as well as the emissions intensity of its electricity providers (the benchmark would be in units of $MTCO_2e/output$). However, as we illustrate in subsequent subsections below, such an approach introduces the potential for perverse outcomes wherein an efficient facility could actually receive less allowance revenue than an inefficient facility.

In the draft version of this proposal, Staff originally proposed that the Commission's product benchmark should reflect emissions intensity – total emissions from electricity purchases divided by product output for each industrial sector. Based on discussion at the June 7, 2013, public workshop and informal comments provided after the workshop, Staff now recommends that the Commission should develop a benchmark that reflects electricity intensity. This

preference is based on evidence that an emission benchmark could result in perverse outcomes and on the fact that industrial facilities have limited ability to choose low-GHG sources of electricity or to affect the resource mix of their default electricity providers. In the subsections below we outline formulas for both approaches in the interest of demonstrating how each approach could be implemented.

2.3.2. Sources of Electricity Purchases

Industrial facilities can sprawl over large geographic areas and contain many electricity meters. Facilities may span multiple IOU territories, IOU and publicly-owned utility (“POU”) territories, and may include purchases from utilities and non-utility third parties, including off-site CHP. Staff recommends that the Commission consider all potential sources of electricity purchases when developing product (and energy and refinery) benchmarks. By evaluating all sources of electricity purchases, benchmarks will result in an accurate snapshot of an industrial sector’s historical baseline efficiency. If the Commission were to consider only electricity purchases from IOUs, it would also need to estimate what portion of product output is associated with electricity purchased solely from IOUs. Such an approach would result in benchmarks of questionable correlation to a facility’s actual operations. It would also disadvantage facilities that procure electricity from off-site CHP facilities. Staff believes it is more practical, rational and consistent with D.12-12-033, to consider a facility’s total electricity purchases, including those from investor-owned utilities, publicly-owned utilities (“POUs”), off-site CHP facilities, and other third-parties.

2.3.3. Geographic Scope of Benchmark

Though ARB had a clear mandate to calculate statewide benchmarks that account for all covered entities in an industry, the Commission has an option to

calculate statewide benchmarks or to calculate benchmarks that evaluate only covered entities that operate in an IOU's service territory. As we discuss below, the Commission will rely on ARB's MRR data to calculate each industrial facility's electricity purchases and product output. It appears to be technically possible to identify in MRR data which covered entities are either located in an IOU's territory or are an IOU customer. However, Staff believes it is more reasonable to mirror ARB's approach by calculating electricity intensity benchmarks that account for all California facilities in a sector, even though the Commission will only allocate revenue to facilities that operate in an IOU's territory. A decision to limit the scope of an industry benchmark solely to covered entities in IOU territories is an arbitrary one: the effect would be to compensate EITE entities only in relation to whichever of their competitors happen to be IOU customers. If the intent of a product-based allocation is to address leakage risks (from international and domestic trade) and to create incentives for entities to operate efficiently, then a statewide benchmark would achieve that dual objective more effectively than benchmarks limited to IOU customers. Staff therefore proposes that the Commission should calculate product-based benchmarks based on all covered entities in the state that engage in a given industrial activity. This approach parallels ARB's methodology; it produces a more realistic index of industry performance; and it would avoid the administrative complexity of parsing facilities in IOU territories from those in POU territories.

2.3.4. Impacts on CHP

Facilities that rely on on-site CHP tend to be more directly emissive than comparable facilities that purchase electricity from third parties. Because the benchmark variable is a sector-wide average, ARB's direct emissions benchmark

results in an under-allocation to entities that have on-site CHP and an over-allocation to entities that purchase their electricity from third parties. The CPUC's allocation for electricity purchases will correct this outcome – the dynamic of relative over and under-allocation will be applied in reverse: facilities that have on-site CHP will tend to lower the benchmark of electricity purchases because they self-generate electricity, which does not count as an “electricity purchase” in the Commission's benchmarks, and facilities that purchase the majority of their electricity will tend to raise the benchmark. In the end, ARB's direct emissions benchmark and the Commission's electricity purchases benchmark should effectively balance out to ensure that facilities are not unjustly penalized for opting to procure electricity from on-site CHP or from a third-party.

Some industrial facilities may self-generate all of their electricity needs with on-site CHP and may not purchase retail electricity from an IOU. As long as such facilities operate in an IOU territory, pay standby charges or departing load charges to an IOU, they should be eligible for an allocation of allowance revenue from the Commission.

2.3.5. Updates to Benchmark

Staff supports ARB's intention to not update benchmarks over time. ARB calculated product-based benchmarks once at the outset of the Cap-and-Trade program, and Staff likewise proposes that the Commission should only calculate benchmarks once. However, we recommend that the Commission reserve the right to update or revise benchmarks in the future if ARB decides at a later date to revise the benchmarks or the benchmarking methodologies defined in its Cap-and-Trade regulation.

2.3.6. Staff Discretion

Staff also recommends that the Commission grant Energy Division authority to use its discretion to modify data sources or historical periods for certain industries, depending on data limitations or unique factors that may arise in the course of implementation that we have not yet envisioned. The formulas themselves should be fixed, but certain inputs may need to be modified on a case-by-case basis when material issues arise that would result in perverse outcomes. We do not envision specific issues that currently require the use of such discretion; however, we acknowledge that ARB staff has been faced with circumstances that require, for example, using a different historical period for certain industries. We propose that the Commission further consider whether Energy Division should be given authority to exercise such discretion on its own, or through modifications approved via Commission resolution.

2.3.7. Emissions Intensity Benchmark Equation

An emissions intensity benchmark for electricity purchases evaluates total indirect emissions from electricity purchases per unit of product output.

Generic Formula for a Benchmark for Electricity Purchases:

$$B_{EP} = \frac{\sum(EP \times EF)}{\sum Production}$$

Where:

“EP” represents the total electricity purchases in an industrial sector over an historic period.

“EF” represents the GHG emission factor associated with electricity purchases by an industrial sector.

“Production” represents the total production in an industrial sector over an historical period.

Equation 5 below modifies the formula proposed in Appendix A to D.12-12-033 to demonstrate that the summations occur over an entire industrial sector and to clarify that electricity purchases from each utility or third party will have different emissions factors that should be taken into consideration. Additionally, it is possible for a single industrial facility to purchase electricity from multiple IOUs and from multiple third parties, each with their own emission factors, all of which should factor into the numerator's sum of total emissions from electricity purchases.

Equation 5. Emissions Intensity Benchmark Equation for Product-Based Allocation

$$B_{EP,a} = 0.9 \times \frac{\sum_{b=1}^n [\sum_{IOU=1}^u (EP_{b,IOU} \times EF_{IOU}) + \sum_{3rd\ party=1}^p (EP_{b,3rd\ party} \times EF_{3rd\ party})]}{\sum_{b=1}^n Production_b}$$

Where:

“b” is an individual industrial facility that operates in industrial activity “a” outlined in Table 9-1 of ARB’s Cap and Trade regulation.

0.9 is a benchmark stringency factor chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities for each industrial activity. For sectors in which there is only one covered entity or in which no covered entity is at least as efficient as the benchmark, 0.9 is not used and instead the benchmark is set based on the “best-in-class” value (i.e. the emissions intensity of the most GHG-efficient California facility).

“EP_{b,IOU}” is the total electricity purchased in MWh by industrial facility “b” from an IOU. Electricity purchases by a single facility “b” may occur from one or more IOUs, each with its own associated emission factor. Electricity purchases are summed over a historical period, 2008-2010, using ARB’s MRR data.

“ EF_{IOU} ” is the GHG emissions factor specific to each IOU from which the industrial facility “b” purchased electricity. Each IOU may have its own emissions factor. Emissions factors are discussed at greater length in Section 2.3.9 below.

“ $EP_{b, 3rd\ party}$ ” is the total electricity purchased in MWh by industrial facility “b” from a third party electricity provider. Electricity purchases by a single facility “b” may occur from one or more third party providers, each with its own associated emissions factor. Electricity purchases are summed over a historical period, 2008-2010, using ARB’s MRR data.

“ $EF_{3rd\ party}$ ” is the GHG emissions factor specific to the third party electricity provider. Each third party may have its own emissions factor. Emissions factors are discussed at greater length in Section 2.3.9 below.

“ $Production_b$ ” is the total output, produced by industrial facility “b”, for the industrial activity for which the benchmark is being calculated. Product output is summed over an historical period 2008-2010, using ARB’s MRR data.

This equation has the effect of averaging the emissions factors of various electricity providers in an industry. For example, if an industry has only two facilities, each of which has the same historical baseline product output and the same quantity of electricity purchases, but one facility is located in a relatively clean IOU territory and other is located in a relatively emissive IOU territory, the benchmark would effectively reflect the average of the two IOUs’ emissions factors. As a result, the facility in the clean IOU territory would receive a windfall and its equally efficient competitor would receive a revenue shortfall. Though it may be appropriate in the long-run to encourage industrial development in low-GHG IOU territories, such an outcome may not be relevant

or ideal in the present circumstance when considering well-established industrial facilities that cannot easily uproot from one IOU territory to another.

A more explicitly perverse outcome is also possible if we pursue the emissions intensity benchmarking approach of Equation 5. If we use the same hypothetical above but instead assume that one facility is more efficient than its competitor, and that this efficient facility is in the territory of the more emissive IOU, it is possible for an inefficient facility to receive a windfall. The Large Users demonstrated the potential for this outcome during the June 7, 2013, workshop and in informal comments, which we replicate in Appendix B. It is largely to avoid this potential outcome that we recommend the Commission pursue the electricity intensity benchmark approach below.

2.3.7.1. Electricity Intensity Benchmark Equation

Staff recommends that the Commission develop an electricity intensity product benchmark for the product-based allocation. To do this involves a single simplification of Equation 5: we simply remove the emission factor, EF , from the equation. All other variables remain the same.

Equation 6. Electricity Intensity Benchmark Equation for Product-Based Allocation

$$B_{EP,a} = 0.9 \times \frac{\sum_{b=1}^n (\sum_{IOU=1}^u EP_{b,IOU} + \sum_{3rd\ party=1}^p EP_{b,3rd\ party})}{\sum_{b=1}^n Production_b}$$

Where:

“ $B_{EP,a}$ ” is the electricity intensity benchmark for industrial activity
 “ a ” in units of MWh per product output.

Since we have removed the emissions factor from the benchmark, we now need to introduce the emissions factor variable to the product-based allocation

formula expressed by Equation 3 so we can convert electricity purchases into emissions. The sole change to this equation is the introduction of an emissions factor.

Equation 7. Revised Product-Based Allocation Formula for Prospective Allocation (Replaces Equation 3)

$$Allocation_{b,t} = \left(\sum_{a=1}^n (O_{a,t-2} \times B_{EP,a} \times AF_{a,t} \times C_{a,t} \times D_{t-1}) \right) \times EF_{b,initial}$$

Where:

“ $EF_{b,initial}$ ” is the emissions factor in $MTCO_2e/MWh$ specific to industrial facility “b” during an “initial” year, as defined below in Equation 8. This emissions factor will vary for each year “t” according to the source of facility “b’s” mix of electricity purchases as well as each source’s own emission factor, as discussed in Section 2.3.9.

This new emission factor, EF , is specific to each industrial facility, and it reflects each facility’s choices about its electricity sources. It must account for two factors that change over time: the annually varying mix of the industrial facility’s electricity sources, and the varying emissions intensity of each electricity source. Each industrial facility makes different decisions about its sources of electricity providers: one may choose to buy entirely from an IOU, another may have certain accounts tied to a utility and others sourced from an ESP, and yet another facility may buy the majority of its electricity from a third-party CHP facility with only standby power from an IOU. Each industrial facility’s emission factor must therefore represent a weighted average of the emissions factors of its electricity providers. As we discuss and recommend in Section 2.3.9 below, Staff recommends that each electricity provider should have its own emissions factor.

We note that this entire approach would be moot if the Commission were to decide to use a fixed, statewide emission factor for electricity purchases.

Staff recommends that each industrial facility's emissions factor should be updated on an annual basis. Annually-updating emissions factors are important, in this case, because emissions have been removed from the benchmark variable, which remains fixed. As a result, the emissions factor is an indicator of changes in the cost burden faced by industrial facilities. If this cost burden changes as a result of changes in the electricity provider's emissions intensity or due to changes in the industrial facility's choices about its source of electricity, these changes should be reflected in the allocation that each facility receives. For example, if a facility procures electricity entirely from an IOU, the IOU's emissions intensity may increase or decrease over time. Assuming for illustration purposes that the dollar conversion factor, D , remains constant, an increase in IOU emissions intensity will lead the facility to experience an increase in GHG costs somewhat beyond its control that should be addressed in the allocation methodology. Conversely, if the IOU's emissions intensity decreases over the course of the Cap and Trade program, this would correspond to a decrease in the cost burden faced by the industrial facility and the facility would require less allowance revenue.

We concede that it is administratively simpler to calculate a fixed, historical baseline emission factor specific to each industrial facility. However, once the emissions factor is removed from the benchmark equation we believe it is more consistent with the intent of the Cap and Trade program, and it is more rational, to annually update each facility's emissions factor and each electricity provider's emissions factor (as we discuss in Section 2.3.9 below).

Equation 8. Industrial Facility-Specific Weighted Average Emissions Factor

$$EF_{b,t} = \frac{\sum_{provider=1}^n (EP_{b,provider,t} \times EF_{provider,t})}{\sum_{provider=1}^n EP_{b,provider,t}}$$

Where:

“b” is an individual industrial facility that operates in industrial activity “a” outlined in Table 9-1 of ARB’s Cap and Trade regulation.

“ $EP_{b,provider,t}$ ” is the total electricity purchased in MWh by industrial facility “b” from each electricity provider in year “t,” as reported in ARB’s MRR data.

“ $EF_{provider,t}$ ” is the GHG emissions factor specific to each electricity provider from which the industrial facility “b” purchased electricity. Each provider has its own emissions factor, as discussed in Section 2.3.9 below.

This formula poses an additional timing-related complication: verified MRR data for electricity purchases by facility is not available in year “t” due to the time lag between when verified data is reported, and when a facility incurs GHG costs. For example, if we wish to grant a prospective allocation to address 2014 GHG costs, that allocation would be made in Q1 of 2014, at which time facilities will have only reported verified data about electricity purchases in 2012. Similarly, according to the IOU and POU emissions factor options we propose below in Table 1, these factors will rely on data about each utility’s total sales in a given year. As of Q1 2014, the CPUC will know IOU forecasts of 2014 sales, but not actual sales. For POUs, the CPUC has no means of knowing sales forecasts, so we must rely instead on public data reported to FERC (a one-year lag) or to the EIA (a two-year lag).

This time lag requires us to define two equations for an industrial facility’s emissions factor: an “initial” emissions factor used when performing the

allocation for budget year “t” costs; and a “trueup” emission factor used when truing-up each facility’s revenue allocation. The formula for the initial emissions factor is expressed in Equation 9 below. The “trueup” emissions factor would be calculated exactly as expressed in **Equation 8** above, once actual MRR data and utility sales data for year “t” are available in year “t+2.”

Equation 9. Initial Industrial Facility-Specific Weighted Average Emissions Factor

$$EF_{b,initial} = \frac{\sum_{provider=1}^n (EP_{b,provider,initial} \times EF_{provider,initial})}{\sum_{provider=1}^n EP_{b,provider,initial}}$$

Where:

“ $EP_{b,provider,initial}$ ” is the most recent year of ARB MRR data about total electricity purchased in MWh by industrial facility “b” from each electricity provider. For an allocation that addresses GHG costs incurred in budget year “t,” the most recent year of verified MRR data would be year “t-2.”

“ $EF_{provider,initial}$ ” is the GHG emissions factor specific to each electricity provider from which the industrial facility “b” purchased electricity, as discussed in Section 2.3.9 below, based on the most recent year of public data of annual utility sales at the time the allocation is granted. Public data for both POU and IOU sales for budget year “t” will be available in year “t+2.”

Since we will not be able to calculate each industrial facility’s actual emission factor until year “t+2,” we must add another factor to the true-up Equation 4 for a prospective product-based allocation.

Equation 10. True-Up Term for a Prospective Allocation, Added to Equation 7 (Replaces Equation 4)

$$Trueup_{b,t} = \left(\sum_{a=1}^n (AF_{a,t-2} \times B_{EP,a} \times C_{a,t-2} \times) [(O_{a,t-2} \times D_{t-2}) - (O_{a,t-4} \times D_{t-3})] \right) \times (EF_{b,trueup} - EF_{b,initial})$$

2.3.8. Benchmark Stringency Factor

ARB's benchmark formulas, and the complementary formulas we propose above, include a 90% stringency factor; however, there are certain limited circumstances in which a benchmark should be based on a "best-in-class" value. When developing its product-based benchmarking methodology, ARB evaluated "each industrial sector's production weighted average emissions intensity during a historical base period [and then targeted] the benchmark to allocate 90 percent of this level per unit product."²⁷ The intent of the stringency factor is to create a benchmark that reflects the emissions intensity of highly efficient, low-emitting facilities within each sector. When evaluating the results of these benchmark values, ARB staff found that for some sectors the stringency approach resulted in a benchmark level that was more stringent than the current emissions intensity of any existing Californian facility in the sector. For the sectors in which this occurred, ARB applied a benchmark to that sector that was based on the "best-in-class" value for that sector (i.e. the emissions intensity of the most GHG-efficient California facility).²⁸

²⁷ ARB July 25, 2011, Notice of Public Availability of Modified Text, Appendix B: Development of Product Benchmarks for Allowance Allocation, p. 3. Available at:

<http://www.arb.ca.gov/regact/2010/capandtrade10/candtappb.pdf>

²⁸ Ibid, p. 3.

We recommend that the Commission take the same approach as ARB. The stringency approach in Equation 5 and Equation 6 should be applied to all industries, except that the “best-in-class” approach should be used for sectors:

- With one covered entity; or
- In which no covered entity is at least at the efficiency of the benchmark.

The Joint IOUs asserted that the stringency approach has no basis in analysis.²⁹ ARB developed the stringency approach through a public process with opportunity for stakeholder comment. The relevant question facing the Commission is whether there is reason to deviate from ARB’s basic approach. Staff believes that a deviation from ARB’s stringency approach would result in perverse outcomes: the exclusion of a stringency factor from the indirect allocation would have the effect of disadvantaging facilities that choose to generate their own electricity on-site via combined heat and power plants. Since the stringency approach applies to direct emissions, it must also apply to indirect emission from electricity purchases to avoid irrationally advantaging those facilities that procure their electricity rather than generate it onsite.

To implement the benchmark calculations, Energy Division will need ARB to communicate, by November 2013, which industrial sectors in Table 9-1 of the Cap-and-Trade regulation have only one covered entity, and which received a direct allocation of allowances based on a best-in-class benchmark approach.

2.3.9. Emissions Factors

ARB’s Cap-and-Trade regulation did not specifically address what emissions factors are appropriate to use when evaluating the emissions associated with electricity purchases, though it did specify that electricity

²⁹ Large IOUs Joint Pre-Workshop Comments, p. 4-5.

exported by industrial entities should be assigned an emissions factor of 0.431 MTCO_{2e}/MWh.³⁰ As a result, the Commission has latitude to evaluate the merits of two principal options for calculating the emissions factor variable, “EF,” that should be used in its revenue allocation methodologies: 1) a single statewide emissions factor that applies to all electricity purchases; or 2) emissions factors specific to each type of electricity provider, whether they are IOUs, publicly-owned utilities (“POUs”), or other non-utility electricity providers.

To evaluate these policy options, Staff recommends that the Commission attempt to balance the following objectives:

- Avoid creating windfalls for covered entities
- Avoid inequities between on-site and over-the-fence CHP
- Avoid creating perverse incentives that would alter a covered entity’s rational decision-making to either purchase from an IOU, to self-generate, or to purchase from a third party.
- Develop accurate emissions factors
- Maintain consistency with ARB regulations
- Achieve administrative simplicity

2.3.9.1. Use of a Single Statewide Emissions Factor

The most administratively simple option is to establish a single statewide emissions factor that would apply to all electricity purchases, regardless of the electricity provider. This approach has its drawbacks: if the factor is too high it has the potential to result in significant windfalls to facilities that purchase the majority of their electricity from IOUs; conversely, if the factor is too low it could result in revenue shortfalls for facilities that purchase electricity from over-the-fence CHP generators. Moreover, it would not accurately reflect the physical

³⁰ 17 CCR § 95891(c)

realities of the electricity market and differences between utilities, which have large portfolios of zero-emission resources, and purchases from third-party CHP facilities, which typically generate electricity from a single natural gas-fueled generator. Finally, it could create an inequity between on-site CHP and over-the-fence CHP.

In their pre-workshop comments, the Joint IOUs proposed that the Commission should use an emissions factor of 0.431 MTCO_{2e}/MWh, which ARB uses in its direct allocation methodologies as the emissions benchmark for each unit of electricity sold or provided to off-site end users. Staff has significant reservations about the use of this value as a statewide emissions factor for all electricity purchases. A factor of 0.431 MTCO_{2e}/MWh is substantially higher than the average portfolio emissions factor of any single IOU, as we illustrate in Section 2.3.9.2 below. Its use would indisputably lead to windfalls for EITE facilities that purchase electricity from IOUs, and potentially also to those facilities that purchase electricity from efficient over-the-fence CHP generators. This factor ignores the fact that a large portion of utility and direct-access providers' portfolios consist of zero-emission electricity, due to their obligation to comply with the Renewable Portfolio Standard.

Though Staff does not recommend that the Commission use a single statewide emissions factor, we propose that 0.378 MTCO_{2e}/MWh and 0.34 MTCO_{2e}/MWh are both more reasonable statewide emissions factors than 0.431 MTCO_{2e}/MWh. The emissions factor of 0.378 MTCO_{2e}/MWh results from dividing weighted average statewide electricity emissions from 2008 to 2010, including those from electricity imports, by total statewide electricity

consumption during these same years.³¹ Alternatively, the Commission could use the 2008 baseline statewide emissions factor of 0.34 MTCO_{2e}/MWh included in the Commission's public GHG Calculator developed by E3.³² Both of these factors represent a middle ground between more accurate estimates of IOU emissions factors proposed below, and a factor of 0.431 MTCO_{2e}/MWh, which more nearly represents a historic emissions factor associated with marginal natural gas generators.

2.3.9.2. Utility and Third-Party Specific Emission Factors

Staff prefers to use emissions factors that distinguish between each potential source of electricity purchases. Ideally, emissions factors should be specific to each IOU and to each third party electricity provider (including POUs, electricity marketers, and over-the-fence CHP facilities). This approach would result in a higher degree of accuracy and fairness, compared to the use of a statewide emission factor, and it would minimize the potential for windfalls and inequities. Additionally, this approach mirrors the clear intent of ARB's allocation methodologies and AB 32 to account for actual emissions as accurately as practicable. However, we acknowledge that there can be a tradeoff between accuracy and administrative complexity.

California has four principal groups of electricity providers: IOUs; POUs; direct access, community choice aggregators and electric service providers (i.e. electricity marketers); and off-site CHP facilities (i.e. CHP generators that are situated off-site from industrial facilities that purchase electricity and/or steam from these generators). The Commission must address these four sources of

³¹ This analysis is based on ARB's MRR data on statewide emissions associated with electricity production. Electricity consumption data are based on electricity consumption data published by the CEC at <http://www.ecdms.energy.ca.gov/elecbyutil.aspx>.

³² See the GHG Calculator Version 3c, "Outputs" tab, updated October 7, 2010, and available at http://www.ethree.com/public_projects/cpuc2.php.

electricity purchases because a single industrial facility may purchase electricity from one or more types of electricity providers. The approach we recommend below is an effort to capture real differences in emissions intensity between these different types of electricity providers, while also avoiding inequities and unjustified complexity.

Staff believes there is value in evaluating on an ongoing basis the IOUs' actual emissions factors; however we do not believe this exercise is absolutely necessary for the purpose of allocating allowance revenue to EITE entities. If the Commission does require each IOU to calculate its actual annual emissions factor as part of the annual applications required by D.12-12-033, these emissions factors could be used as the basis for the IOU emissions factors in the EITE allocation formulas. However, we propose a different approach in Table 1 below. Our reasoning is twofold: the Commission cannot compel POUs to conduct similar calculations of actual emissions factors, and we believe a simpler approach, using public data that are available for both POUs and IOUs, can achieve reasonable results for the purpose of emissions benchmarking and revenue allocation to EITE entities.

In Table 1 below, we propose three potential methods of calculating IOU and POU emissions factors. Options A and B treat ARB's allowance allocations to each utility as proxies for a utility's total portfolio emissions from electricity procurement (including procurement associated with line losses). ARB allocated allowances to individual IOUs and POUs based on its analysis of 2009 Form S-2 data that all utilities provide annually to the California Energy Commission.³³ These forms reflect each utility's historical and projected resource mixes. ARB allocated allowances to each utility based on "cost burden" – actual emissions that will result from generation resources in a utility's portfolio, including fossil-

³³ For S-2 source data, see http://energyalmanac.ca.gov/electricity/S-2_supply_forms_2009/.

fueled and non-emitting resources – as well as two additional factors: cumulative investments in energy efficiency, based on the past performance and expected execution of energy efficiency programs by each utility, and early action investments in qualifying renewable energy.³⁴ “Cost burden” reflects the portion of allowances allocated to ratepayers to address the current (as of 2009) and forecast emissions profile for each utility. However, ARB allocated additional allowances to utility ratepayers to recognize expected future energy efficiency savings from investments made to date, as well as early action investments in renewables to date (i.e. from 2007 to 2011).³⁵ Option A below would result in emissions factors based on total allowance allocations to each utility (which includes credits for energy efficiency and renewable investments). Option B reflects the portion each utility’s allowance allocation specifically intended to address ratepayer cost burden (i.e. it excludes credits for energy efficiency and renewables). Option C points to 2008 baseline utility and region-specific emissions factors published in the Version 3 of the Commission’s GHG Calculator developed by E3, last updated in 2010.³⁶ Regardless of which methodology the Commission ultimately approves among Options A through C, we recommend that emission factors for IOUs and POUs should be calculated via the same methodology.

³⁴ For background on ARB’s methodology of allocating allowances to electric sector ratepayers, see Appendix A to ARB’s July 25, 2011, Public Notice, “Staff Proposal for Allocating Allowances to the Electric Sector,” available at <http://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf>.

³⁵ The sum of all individual IOU and POU allocations was capped at a maximum electricity sector allocation set at 90% of 2008 electricity sector emissions. However, this cap exceeded the sum of ARB’s cost burden allocations to individual utilities; the implication for our purposes being that each utility’s annual cost burden allocation was not reduced by a 90% stringency factor, as an IOU representative suggested during the June 7 workshop. The difference between the maximum electricity sector allocation and the sum of all utilities’ cost burden allocation is equivalent to the total amount of allowances that ARB allocated to utilities for energy efficiency and early action RPS credits. In general, approximately 1% of each utility’s allocation was credited for energy efficiency investments, and approximately 5% was allocated in recognition of early action renewable energy investments. In all cases, each IOU’s total allowance allocation exceeded ratepayer cost burden.

³⁶ See “GHG Calculator version 3c” available at: http://ethree.com/public_projects/cpuc2.php. Direct file download available at: http://ethree.com/documents/GHG%20update/GHG%20Calculator%20version%203c_Oct2010.zip.

For electricity sold by DA/CCA/ESP providers, Staff recommends that the Commission apply the emissions factor of the interconnecting or host IOU. In D.12-12-033, the Commission requires that small business and residential customers of IOUs and DA/CCAs receive an equivalent \$/kWh revenue allocation. This is in effect a statement that the emissions intensity of each IOU should be used as a benchmark for the emissions intensity of DA/CCA providers in the IOUs' respective territories. This decision was intended to ensure that neither IOUs nor DA/CCAs are given a competitive advantage or placed at a disadvantage relative to one another. As a practical matter, it is also unclear how the Commission could estimate DA/CCA providers' emission factors based on public data or on ARB's MRR data.

During the public June 7, 2013, workshop and in informal comments to Energy Division, the Large Users and Gerdau argued that the Commission should use a different emissions factor for DA/CCA/ESP providers than for utilities because electricity marketers do not have the benefit of zero-emission resources such as hydro and nuclear baseload generators. This position implies that energy marketers do not have the same ability to procure energy from such resources. These parties offered an alternative emissions factor for DA/CCA/ESPs based on the implied emissions rate of the CAISO wholesale market. On May 29, 2013, CAISO released its Q1 2013 Report on Market Issues and Performance,³⁷ which reported CAISO's estimate that Cap and Trade has so far resulted in an average \$6.15/MWh increase in wholesale market prices during Q1 2013. CAISO also estimates that the cost of GHG emissions was \$14.55/MTCO_{2e} during this same quarter, calculated as an average of the Intercontinental Exchange (ICE) and ARGUS Air Daily indices. Based on these

³⁷ Available at http://www.caiso.com/Documents/2013FirstQuarterReport-MarketIssues_Performance-May2013.pdf

two figures, the Large Users note that the implied emissions rate of the wholesale market was 0.42 MTCO_{2e}/MWh during the quarter. The Large Users argue as a result that 0.42 MTCO_{2e}/MWh is a more appropriate emissions factor for DA/CCA/ESP customers.

Staff acknowledges that the implied emissions rate of the wholesale market will almost certainly be higher than the portfolio emissions rate of the large IOUs, but we disagree with the assessment that DA/CCA/ESP emission factors should be tied to the implied emission factor of the wholesale market. Each IOU and DA/CCA/ESP provider is required to comply with the state's renewable portfolio standard, and each electricity provider may make use of a range of procurement options. As a result, only a portion of an IOU's portfolio emissions are tied to the implied emissions of the wholesale market. Similarly, the emissions factor of DA/CCA/ESPs would only be matched with the average wholesale market's emissions factor if the energy marketer were 100% exposed to the wholesale market. Such an outcome would more accurately reflect an energy marketer's business decisions than structural inequities due to historic IOU investments in hydro and nuclear resources, and it is not possible for the Commission to easily assess to what extent an energy marketer's portfolio emissions reflect the CAISO wholesale market average.

As a practical matter, we also note that SCE and SDG&E no longer have nuclear resources in their portfolios, and they have limited quantities of large hydro resources. Therefore, this particular argument is essentially moot in these territories. If the Large User's argument were valid, it would only pertain to customers in PG&E's territory, which does have a significant portfolio of nuclear and large hydro resources (in a high hydro year). To further put the scope of this concern in context, Energy Division's analysis of utility data indicates that

approximately 80% of all EITE electricity purchases in 2012 were from IOUs and 20% were from electricity marketers.

Though the EITE allocation is intended to address indirect GHG costs that industrial facilities face in electricity rates, the Commission committed in D.12-12-033 to ensuring that neither IOUs nor energy marketers have a competitive advantage. If the Commission were to apply a higher emissions factor to energy marketers than to IOUs, the Commission would incentivize procurement from an implicitly more emissive resource, and we would advantage energy marketers over IOUs – an outcome we seek to avoid. We are not persuaded that a significant structural inequity exists, in this case, that would justify allowing all EITE customers of DA/CA/ESPs to receive a greater amount of revenue than equivalent facilities that are customers of IOUs.

Table 1. Methodologies to Calculate Electricity Provider Emissions Factors

Option	IOUs	POUs	DA/CCA/ESPs	Off-site CHP
A	Divide the total direct allowance allocation for each utility in a given year, as specified in Table 9-3 of ARB's Cap-and-Trade regulation, by total retail sales for each utility in the same year. ³⁸		Apply the emissions factor of the interconnecting or host IOU. ³⁹	Use the same emissions factor, 0.431 MTCO ₂ e/MWh, that ARB applied to electricity sold or provided to off-site end users by industrial entities.
B	Adjust Option A by discounting the total direct allowance allocation to reflect ratepayer cost burden. ⁴¹			0.431 MTCO ₂ e/MWh
C	Use emissions factors reported in the E3 GHG Calculator Version 3c (2008 baseline case). For POUs other than SMUD or LADWP, apply the emissions factor for "Northern Other" or "Southern Other" utilities, as appropriate. For PacifiCorp and CalPeco, use the value for "Northern Other" utilities.			0.431 MTCO ₂ e/MWh

³⁸ For this calculation, we will use the IOUs' annual forecasts of total sales (bundled and unbundled). Since we propose in Section 2.3.7 to update each industrial facility's emissions factor over time, when triuing up a facility's emissions factor we will use actual electricity sales data once it is available. When calculating emissions factors for POUs, Energy Division will use public data from FERC Form 1 filings, or 2011 EIA Form 861.

³⁹ In all Options A-D, the emissions factor for DA/CCA/ESPs would be equivalent to that of the interconnecting or host IOU.

⁴¹ ARB's allocation to individual utilities included a majority intended to address ratepayer cost burden, plus additional allocations to include cumulative energy efficiency accomplishments and early action investments in RPS-eligible renewables.

For off-site CHP, we propose that the Commission use the same 0.431 MTCO₂e/MWh emissions factor that ARB applies to electricity sold or provided to off-site end users by industrial entities. Though we would prefer to calculate each CHP facility's actual emissions factor based on ARB's MRR data, we believe a simpler approach is justified for two reasons: 1) ARB's use of an emissions factor of 0.431 MTCO₂e/MWh for electricity exports in its direct allocation acts as a constraint that the Commission must consider, and it creates a possibility that inequities between on-site and over-the-fence CHP could arise if the Commission's allocation uses a substantially different emission factor. 2) To develop emissions factors for each CHP facility is technical possible - ARB has adequate MRR data - but the effort to develop a methodology to evaluate what portion of a CHP facility's total emissions should be allocated between electricity production and useful steam production would require significant staff time, both to develop and to implement the methodology, and it is not clear that this approach will necessarily provide a public benefit, given our reservations about potential inequities and the existence of a reasonable alternative.

However, we note that the use of 0.431 MTCO₂e/MWh for off-site CHP has the potential to disadvantage facilities that have highly-efficient on-site CHP and that receive revenue according to the refinery or energy-based allocation. For example, if a refinery has a highly efficient on-site CHP unit for electricity production, emissions associated with this electricity production would be accurately reflected in the refinery's total direct emissions. The emissions from this unit are direct, on-site emissions, and they factor into a facility's compliance obligation. For an efficient CHP facility, the emissions factor for this on-site electricity generation could be lower than 0.431 MTCO₂e/MWh, in which case a refinery that has on-site CHP would receive less overall compensation (allowances and allowance revenue) than a refinery that purchases electricity

from an off-site CHP facility, even if the off-site CHP facility operated at the same high level of efficiency. This circumstance could arise in the case of an energy-based or refinery allocation because both of these methodologies rely on facility-specific benchmarks based on historical baseline emissions rather than a sector-wide average. Despite this potential outcome, Staff recommends that the Commission maintain consistency with ARB's fixed 0.431 MTCO_{2e}/MWh factor for electricity exports, unless ARB revises this factor at a later date in favor of a methodology that captures the efficiency of each CHP facility's actual operations.

Based on our recommendation in Table 1, we provide preliminary IOU emissions factors in Table 2, below, to illustrate the results of Options A through C. The difference between Options A and B is the simple deduction of 4% to 8% of each utility's allowance allocation associated with energy efficiency and early action RPS credits, which has the effect of reducing each utility's emissions factor. To calculate Option B, Staff relied on data provided by ARB, which indicated what portion of each IOU's allowance allocation was intended to address utility ratepayers' cost burden.

Table 2. Summary of IOU Emissions Factors for 2013

Utility	Option A: Total Allowance Allocation Basis (MTCO _{2e} /MWh)	Option B: Cost Burden Adjustments ⁴² (MTCO _{2e} /MWh)	Option C: E3 GHG Calculator (2008 Baseline) (MTCO _{2e} /MWh)
PG&E	0.291		0.24
SCE	0.387		0.31
SDG&E	0.331		0.33
PacifiCorp	0.895 ⁴³		0.43
CalPeco	0.401		0.43

⁴² We have decided to redact the results from this calculation out of concern that IOU-specific cost-burden factors may be confidential. Staff will continue to work with ARB and the IOUs to determine whether these factors, and the resulting emissions factors, can be shared publicly.

⁴³ Data for PacifiCorp is based on 2012 retail sales.

PacifiCorp's emissions factor appears high relative to the other utilities, but this is not without justification. ARB treats multi-jurisdictional utilities ("MJUs") differently than the Large IOUs, which operate solely within the state. ARB calculates the compliance obligation for MJUs based on the utilities' total California sales, less any sales served by in-state resources. For retail load not met by in-state generation resources, ARB applies the emissions factor of the MJU's entire system, excluding emissions from in-state generation facilities, which have their own compliance obligation. PacifiCorp's higher emissions factor therefore reflects the fact that PacifiCorp's system includes a significant portion of out-of-state coal generation.

PacifiCorp and CalPeco were not explicitly addressed in the E3 GHG Calculator; however, the calculator does provide emission factors for Northern California, Southern California, SMUD, LADWP, and California as a whole.⁴⁴

Given the three options outlined in Table 1, Staff recommends that the Commission use the emissions factors defined in Option A. We believe this option most closely aligns with ARB's allocation methodologies. Option A compared to Option B also allows for a margin of error to ensure that emissions factors assigned to IOUs and POUs are likely to exceed the maximum cost burden that utility customers are expected to experience between 2013 and 2020. This approach is conservative and of the three options is least likely to result in an unjustified under allocation of allowance revenue to EITE entities.

⁴⁴ These 2008 baseline factors are: SMUD: 0.27; LADWP: 0.55; Northern Other: 0.43; Southern Other: 0.47; Total CA: 0.34.

2.3.10. Industries with Subsector Benchmarks

Through pre-workshop comments submitted by the Large Users, Staff learned that the development of benchmarks poses a particular challenge for industries that have subsector activities. Benchmarking is relatively straightforward in cases when a single facility operates in an industry that has only one benchmark – such as cement manufacturing. Because ARB collects data about a facility’s total electricity purchases, this data can feed directly into the product-based benchmark formula expressed in Equation 6 when a facility operates in only one industrial activity. However, some industrial sectors and facilities span multiple activities, each of which has its own product-based benchmark in ARB’s Cap-and-Trade regulation. For example, the Rolled Steel Shape Manufacturing Sector (NAICS Code 331221) has five different subsector activities and associated benchmarks – hot rolled steel, pickled steel, cold rolled steel, galvanized steel and tin steel plate production. Two Californian companies operate in this sector: USS POSCO and California Steel Industries. Both companies produce multiple types of products included within the Rolled Steel Shape Manufacturing Sector. In this case, ARB’s MRR data about a single facility’s total electricity purchases provides no clear insight into what percentage of USS POSCO’s or California Steel’s electricity purchases are associated with one subsector activity versus another. To calculate benchmarks of electricity purchases for these subsectors and others, the Commission either needs supplemental data from the affected industries, or it needs a method to estimate electricity purchases by subsector based on other available data.

Table 3. Industrial Sectors with Subsector Benchmarks⁴⁵

NAICS Sector Definition	NAICS Code	Activity (a)	Leakage Risk
Crude Petroleum and Natural Gas Extraction	211111	Thermal EOR Crude Oil Extraction	High
		Non Thermal Crude Oil Extraction	High
Paperboard Mills	322130	Recycled Boxboard Manufacturing	High
		Recycled Linerboard (Testliner) Manufacturing	High
		Recycled Medium (Fluting) Manufacturing	High
Industrial Gas Manufacturing	325120	Gaseous Hydrogen Production	Medium
		Liquid Hydrogen Production	Medium
Nitrogenous Fertilizer Manufacturing	325311	Nitric Acid Production	High
		Calcium Ammonium Nitrate Solution Production	High
Gypsum Product Manufacturing	327420	Plaster Manufacturing	Medium
		Plaster Board Manufacturing	Medium
Rolled Steel Shape Manufacturing	331221	Hot Rolled Steel Sheet Production	High
		Pickled Steel Sheet Production	Medium
		Cold Rolled and Annealed Steel Sheet Production	Medium
		Galvanized Steel Sheet Production	Medium
		Tin Steel Plate Production	Medium

⁴⁵ Combined from Tables 8-1 and 9-1 of ARB's Cap-and-Trade regulation.

Based on pre-workshop comments, discussions with representatives of Rolled Steel Shape Manufacturers and Crude Petroleum and Natural Gas Manufacturers, as well as discussions with ARB staff, we propose the following three methods of identifying electricity purchases by industrial subsector.

2.3.10.1. Option 1: Natural Gas Usage as a Proxy

ARB addressed a similar problem in its direct allocation methodologies by identifying what portion of a facility's total natural gas use is associated with each product. To perform this analysis, ARB relied on utility gas meter data, staff-level discussions with industries and analysis of facility-by-facility internal meter data. The results of this analysis were percentage allocation factors that apportion total natural gas use, as reported by industries via MRR, by industrial subsector activity. In their pre-work statement, the Large Users propose that the Commission use ARB's factors for allocating natural gas use by subsector as a proxy for electricity use by subsector. Though Staff recognizes that natural gas use and electricity use by industrial subsector are not necessarily correlated, this approach is attractive for two principal reasons: it is the most administratively simple solution (ARB already has the necessary data), and it can be applied equally to each NAICS Code that has subsector benchmarks. Though this option has the potential to introduce a measure of inaccuracy into the benchmarking process, it is unclear at present whether such an approach has the potential to result in perverse outcomes.

2.3.10.2. Option 2: Voluntary Reporting of Auditable Electricity Data

An alternative approach is to rely on an industrial facility's internal meter records of electricity use by subsector activity. This option would require that industrial entities submit to Energy Division auditable internal records of electricity use, as well as an attestation to their accuracy. These records would be

used to determine what portion of the facility's total electricity purchases, as reported via ARB MRR, are associated with specific subsector activities. This approach offers a higher degree of accuracy than Option 1 above; however, it would place substantially more administrative burden on Energy Division staff to collect and validate data on a facility-by-facility basis.⁴⁶

This approach, however, is not practical for each covered entity. In the Rolled Steel Shape Manufacturing Sector, for example, California Steel indicated that it has only one utility electricity meter for its entire manufacturing facility, in which it produces four different steel products,⁴⁷ and California Steel asserts that other characteristics of its manufacturing process make it difficult to estimate or meter electricity use associated with the production of any single product. For this reason, California Steel prefers Option 1. Conversely, USS POSCO has auditable internal meter data of electricity use by subsector activity, and in post-workshop informal comments submitted to Energy Division on June 14, 2013, it indicated that it supports the use of Option 2 and opposes the use of Option 1 when developing benchmarks that apply to USS POSCO. In informal comments, both USS POSCO and the Large Users recommended developing facility-specific benchmarks unique to USS POSCO and California Steel, using Option 2 for USS POSCO and Option 1 for California Steel.

2.3.10.3. Option 3: Product Output Basis

For other industries, a third approach may be appropriate. In informal post-workshop comments, the Large Users recommended that for the Crude Petroleum and Gas Extraction industry (NACIS Code 211111) the Commission

⁴⁶ Though it is possible to add such a data-reporting requirement to ARB's MRR, it would not be possible to enact such a regulatory change and to collect verified data from industrial facilities in time for Energy Division to perform benchmark calculations in 2013. If such a change were made in 2013, data would not be reported until April 2014 and be verified until September 2014.

⁴⁷ Large Users' Pre-Workshop Statement, Attachment D-1, February 6, 2013.

use relative product output as the basis for splitting electricity purchases by subsector. For example, if a single facility engages in both thermal and non-thermal crude oil extraction, and 60% of its historic output of barrels were produced via thermal oil extraction, the Large Users recommend that 60% of its total facility electricity use should be associated with thermal oil extraction.

2.3.10.4. Recommendations

Staff believes that Options 1, 2 and 3 may be acceptable in different cases and that more analysis is needed to determine the implications of using particular options for each sector. We therefore recommend that the Commission grant Energy Division authority to work with ARB and the industries listed in Table 3 above to determine which option is most appropriate on a sector-by-sector basis.

We do not recommend that the Commission create facility-specific benchmarks when there are two or more facilities that engage in an industrial subsector activity, and we therefore disagree with recommendations by USS POSCO and California Steel that their facilities should each be granted their own benchmarks in subsectors where their operations overlap. The creation of facility-specific product-based benchmarks would be a significant deviation from ARB's methodologies, and we do not believe that the unavailability of 100% accurate data from both facilities is justification enough to make such a significant departure from ARB's approach. Though we decline to commit to a specific approach without further numeric analysis, in the case of the Rolled Steel Shape Sector we believe it would be more reasonable to use Option 2 for the subsector activities in which USS POSCO operates, and that these benchmarks should apply to California Steel. In the sole subsector in which California Steel's operations do not overlap with USS POSCO, we believe it would be appropriate

to use Option 2. Though we acknowledge that USS POSCO and California Steel may have significantly different processes and facilities, we believe it is reasonable to rely on accurate data where it is available, rather than on arbitrary proxy data.

In cases when the Option 2 is used, we recommend that the Commission require industries to provide Energy Division with auditable records of electricity purchases and an attestation to their accuracy, no later than October 1, 2013, so that Energy Division has ample time to complete benchmarking calculations by the end of November. Though we generally recommend throughout this proposal that the Commission mirror the 2008-2010 historical period used by ARB, we acknowledge that it may not be possible to obtain an industrial facility's internal records of 2008-2010 electricity use by subsector activity. We therefore recommend that the Commission grant Staff discretionary authority to rely on other years of data solely for the purpose of identifying what portion of a facility's electricity purchases should be attributed to one subsector activity versus others, if the facility conducts more than one subsector activity.

2.3.11. Updates to Product-Based Benchmarks

ARB designed its direct emissions benchmarks to be calculated once without updates over time.⁴⁸ Likewise, Staff recommends that the Commission's benchmarks, for both the product-based allocation and the energy-based allocation, should be calculated once in 2013 and should not be updated over time. However, if ARB updates its benchmarks or benchmarking methodologies in the future, the Commission may want to evaluate whether there is a need to update its benchmarks for indirect emissions. We also recommend that in instances when ARB transitions an industry from an energy-based benchmark to

⁴⁸ ARB ISOR Appendix J, p. 54.

a newly created product-based benchmark, Energy Division should have authority to automatically create a corresponding product-based benchmark for electricity purchases for this new sector without the need for subsequent procedural action by the Commission.

2.4. Cap Adjustment Factor

The cap adjustment factor establishes the rate at which California's GHG cap will decline over time. Staff recommends that the values used for the cap adjustment factor, *C*, in the Commission's product-based, energy-based and refinery allocation methodologies should exactly match the cap adjustment factors defined in Table 9-2 of ARB's Cap-and-Trade regulation. Table 9-2 defines two series of cap adjustment factors: factors specific to sectors with process emissions greater than 50%, and factors that apply to all other industries. We recommend that ARB's factors for "All Other Direct Allocation" be used in the Commission's allocation methodologies, and for shorthand we refer to these as ARB's default cap adjustment factors.

A limited number of industries – nitrogenous fertilizer manufacturing, cement manufacturing, and lime manufacturing – produce a majority of their emissions as a result of chemical processes associated with the creation of their products, rather than from the direct combustion of fuel. Because these emissions are the result of chemical reactions and there is "no direct method available for reducing the emission intensity of [these] chemical [processes]," ARB defined a cap decline factor specific to these industries, which has a separate rate of decline from the factors applied to all other industries. However, this alternate cap decline factor "in effect [applies] the [default] cap decline factor only to the energy use portion" of an industry's emissions.⁴⁹ ARB's approach for these

⁴⁹ ARB ISOR Appendix J, p. 40.

sectors was to apply the default cap adjustment factor to direct emissions from these facilities, and a separate factor to process-related emissions. The result is a single series of annual cap adjustment factors that accounts for the separate treatment of direct emissions and process emissions.

The Commission's revenue allocation only addresses GHG costs experienced in electricity rates, not costs associated with process emissions, which are the result of chemical reactions unassociated with fuel combustion and are already covered by ARB's direct allocation of allowances. It would therefore be inappropriate to use ARB's cap adjustment factors for sectors with process emissions greater than 50% in the Commission's formulas to address indirect GHG costs experienced through electricity rates. ARB treated direct emissions equivalently across all sectors – even for the fertilizer, cement and lime manufacturing industries – and we find it reasonable to mirror ARB by treating indirect emissions equivalently across all sectors. As a result, we will apply ARB's default cap adjustment factors even for the fertilizer, cement and lime manufacturing industries.

In the Large Users' pre-workshop statement, and also during the June 7 public workshop and in informal comments to Energy Division, the sole entity in the Iron and Steel Mills Sector, the Rancho Cucamonga Mill operated by Gerdau Long Steel North America ("Gerdau"), argued that its electricity usage should be treated in the same manner that ARB's treats industries with process emissions greater than 50% of total emissions. Gerdau stated that the vast majority of its electricity use results directly from its electric arc furnaces, that its operations are already among the most efficient in the world, and that it lacks opportunities for cost-effective indirect emissions abatement opportunities. In addition, Gerdau argues that a fundamental unavoidable minimum amount of electricity is required to melt scrap steel and raise it to the temperature required to make new

steel, and that this fundamental minimum exceeds 50% of its total electricity purchases.⁵⁰ Staff believes there is a distinction between unavoidable emissions that result directly from chemical reactions, as is the case with the fertilizer, cement and lime manufacturing industries, and emissions that result from a manufacturing process that requires energy to power its operations, either in the form of fuel or electricity. Gerdau's indirect emissions fall into the latter category – its demand for electricity is no different from another industry that needs fuel to power an industrial process. To further evaluate the reasonableness of Gerdau's proposal, Staff considered a hypothetical: if Gerdau had used a basic oxygen furnace rather than an electric arc furnace, would Gerdau have qualified for ARB's cap adjustment factor for sectors with process emissions greater than 50%? In this scenario, Gerdau's direct emissions would be vastly greater than they presently are, but these emissions still would not qualify as process emissions. The emissions associated with steel production are more properly tied to fuel use than to the release of GHGs from chemical processes necessary to create an end product. As a result, it would be inappropriate to treat Gerdau differently from other industries, all of which could make a demonstration that a certain minimum amount of energy is necessary to power their operations and make their products. Additionally, the presence of cost-effective emissions abatement opportunities was not factored into ARB's development of its cap adjustment factors, and we see no compelling reason why the Commission should now take into account an industry's cost-effective emission abatement opportunities when evaluating the reasonableness of ARB's default cap adjustment factors. As a result, we do not believe Gerdau is eligible to be

⁵⁰ In support of its position, Gerdau provided a 2011 report produced by the U.S. Department of Energy, "Meeting Energy Efficiency and Emissions Reduction Goals in the U.S. Steel Industry: A Need for a Breakthrough Production Technologies."

awarded allowance revenue based on the cap adjustment factors ARB applies to sectors with process emissions greater than 50%.

2.5. Output Variable

As we discuss in Section 2.1, we propose to use the most recent year of verified product output data reported via ARB's MRR as the source of the industrial product output variable, O , in the Commission's product-output methodology. Each covered entity must report the previous year's product output to ARB in April of each year, and they must provide verified data in September of each year. Entities that have emissions between 10,000 MTCO_{2e} and 25,000 MTCO_{2e} are not required to provide output data under the MRR unless they opt-in to the Cap-and-Trade program. As a result of this time lag between when data are available and when the Commission allocates revenue (according to timing discussed in Section 2.7), the Commission will be allocating revenue each year based on product output from previous years. As a result, the product output data should be trued-up over time to account for a year's actual product output, once it is known.

The exact year of product data used depends on whether the Commission decides to allocate revenue prospectively (at the beginning of the year when costs will be incurred) or in arrears (after a year of GHG costs). We recommend in Section 2.1.4 that the Commission allocate revenue prospectively for year " t ", based on year " $t-2$ " product output data. The allocation in year " t " would therefore be trued-up in year " $t+2$ " after verified product output data for year " t " is available.

2.6. Dollar Conversion Factor

The dollar conversion factor, D , converts metric tons of emissions into dollars. Staff recommends that the Commission adhere to the definition of the

dollar conversion factor proposed in Appendix A to D.12-12-033. The value of this factor should be calculated as the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided. For example, when the Commission is allocating allowances to address GHG costs experienced in 2013, the dollar conversion factor should represent the weighted average market clearing price of year 2013-vintage allowances sold in all four of ARB's quarterly allowance auctions. This calculation should only reflect current auctions, not advance auctions, since current auctions more accurately represent GHG costs during each budget year. If the Commission adopts our recommendation to allocate allowances prospectively at the beginning of each Cap-and-Trade budget year, then the most recent year's dollar conversion factor should be used in the product-based allocation formulas, and this factor should be trued up when the product output variable is trued up.

In their pre-workshop comments, the Joint IOUs proposed that the dollar conversion factor should be defined as the weighted average price of the utilities' consigned allowances at auction. Though IOUs are required to consign 100% of their allowances by the end of each budget year, they have discretion to determine what volume of allowances should be consigned at each auction. It is therefore possible that dollar conversion factor based on the IOUs' auction strategies may not reflect the actual weighted average allowance price of allowances in each year. It is unclear why the public interest, or the interest of industrial entities, is served by an allowance price index that represents only a subset of the allowances sold, rather than the market at large. We therefore decline to recommend that the Commission adopt the IOUs' proposal.

In the June 7 workshop and in informal comments to Energy Division, Gerdau argued that the Commission should use CAISO's GHG allowance price

index, which is an average of ICE and ARGUS Air Daily indices. Gerdau argues that CAISO's index more nearly represents actual GHG costs in wholesale market prices.

Staff believes that it is more reasonable to base the dollar conversion factor on ARB's quarterly auctions than on over the counter ("OTC") allowance markets such as ICE or ARGUS. Allowances are introduced to the market via ARB's auctions, and the bulk of IOU compliance procurement is required to occur at ARB's auctions.⁵¹ ARB's auctions therefore more nearly represent each IOU's GHG costs, and OTC markets represent costs associated with limited hedging activities. Though OTC markets may fluctuate significantly by day, and ARB's auctions occur only quarterly, these two markets should generally follow the same average trends over the course of a year. We note that as of July 2013, the weighted average of ARB's 2013 vintage allowance sold in 2013 is \$13.82, and CAISO's GHG price index for Q1 2013 was \$14.10, roughly a 2% difference.

2.7. Timing

We acknowledge that the Commission has yet to make a final decision about the timing of the residential Climate Dividend authorized in D.12-12-033, and that there could be positive administrative and outreach and education synergies that would justify synchronizing the EITE return with the Climate Dividend. We therefore recommend that it would be appropriate to conduct the EITE return in either the February, March or April billing cycle, depending on when the Climate Dividend occurs, and that all IOUs should be required to return revenue to EITEs in the same month's billing cycle.

The utilities indicate that they will need two months to return revenue to customers once Energy Division communicates how much revenue should be

⁵¹ See Decision D.12-04-046, which sets GHG allowance procurement rules for IOUs, including limits on hedging activities.

returned to each entity. For an EITE return that occurs in the February billing cycle of each year, we recommend the following timeline of activities to implement the product-based revenue allocation:

- September: Verified MRR production output data are available for the previous calendar year.
- October: ARB relays to Energy Division the following information: 2008-2010 electricity purchases for each facility eligible for a revenue return; verified product output by facility for the previous calendar year; the percentage of total natural gas use by subsector activity for each covered entity in an industry that has subsector benchmarks; which eligible facilities are the sole entities in their industrial sectors; which historical periods ARB used to calculate direct emissions benchmarks for each industrial sector.
- November:
 - ARB holds its last quarterly allowance auction in the calendar year; Energy Division calculates the dollar conversion factor for the calendar year.
 - Energy Division and ARB finalize calculations to determine how much revenue should be returned to each eligible industrial facility, including true-ups from previous years, if applicable.
- December 1: Energy Division communicates to IOUs the following information: the primary service agreement, meter number or other identifying account information associated with each facility that should receive revenue; the exact dollar amount of revenue that

should be returned to each facility; and the primary contact information for each facility.

- February billing cycle: IOUs return revenue to each eligible facility specified by Energy Division.

3. Energy-Based Allocation Methodology

ARB's energy-based allocation methodology is a fallback approach to use when a product-based benchmark is impractical to develop for a specific industry or when ARB has not yet developed such a benchmark. Whereas a product-based allocation changes from year-to-year to reflect changes in an industrial entity's product output, an energy-based allocation is based on a fixed historical baseline amount of emissions by facility. Therefore, if a facility experiences a significant increase in demand that requires a corresponding increase in energy consumption, its revenue allocation will not increase to reflect changes in the facility's operations. Additionally, although the energy-based benchmark rewards facilities for boiler efficiency, it does not reward facilities that operate other processes more efficiently than peer facilities in California. Accordingly, Staff recommends that the Commission use the product-based allocation methodology for all industries that currently have a product-benchmark in Table 9-1 of ARB's Cap-and-Trade regulation, and that the energy-based allocation methodology should only apply to those industries that do not have a product benchmark. If ARB expands its list of product benchmarks in the future and transitions an industry from an energy-based to a product-based benchmark, the Commission and Energy Division should automatically reflect such changes in its own allocation methodologies without the need for further procedural action.

3.1. Proposed Formula

To apply ARB's energy-based allocation methodology to emissions from electricity purchases, the Commission must make two simple modifications to ARB's formula: it must revise the emissions benchmark variable, B , to reflect emissions from electricity purchases, and it must introduce a dollar conversion factor, D , to convert allowances into dollars. The formula below reflects these changes, as well as our recommendations in Section 2.3 that the Commission distinguish between electricity purchased from IOUs and electricity purchased from other parties.⁵²

Equation 11. Energy-Based Allocation Formula for an Individual Facility

$$A_t = B_{EP,e} \times AF_{a,t} \times C_t \times D_t$$

Where:

" A_t " is the amount of revenue allocated to the operator of the industrial facility with an energy-based allocation for budget year " t ";

" $B_{EP,e}$ " is the historical baseline annual arithmetic mean amount of emissions resulting from electricity purchases by the industrial facility from an IOU or other electricity provider, measured in MTCO_{2e}, using 2008-2010 emissions as the historical baseline. The formula for this benchmark is defined in Equation 12 below.

" $AF_{a,t}$ " is Assistance Factor for budget year " t " assigned to each industrial activity " a " in Table 8-1 of ARB's Cap-and-Trade regulation. This factor represents the percent of the energy benchmark that will be provided in an allocation, ranging from 30% to 100% in a given budget year. The specific percentage is tied to ARB's determination of an industrial sector's leakage risk and the year for which the allocation is being sought.

⁵² We have made changed to the formula presented in Appendix A to D.12-12-033 for clarity, accuracy and consistency with nomenclature throughout this proposal.

“ C_t ” is the Cap Adjustment Factor for budget year “t.” The cap adjustment factor represents the decline in the overall GHG cap. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB’s Cap-and-Trade regulation. We address the cap adjustment factor in greater length in Section 2.4.

“ D_t ” is the Dollar Conversion Factor calculated based on the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided. This variable is addressed in more detail in Section 2.6.

The first term of **Equation 11**, $B_{EP,e}$, is a facility’s historical baseline emissions benchmark for electricity purchases, which we define separately for simplicity and consistency with the format of the product-based allocation formulas. This factor is specific to each facility that qualifies for an energy-based allocation. It is calculated once at the outset of the Commission’s implementation of the program and is never updated from year to year. This formula for an industrial facility’s historical baseline benchmark is distinct from the emissions benchmark used in the product-based allocation methodology, as expressed by Equation 5. The subscript “e” in the benchmark variable distinguishes the benchmark used in the energy-based methodology from that used in the product-based methodology. Though the benchmark-variable used in the product-based allocation should reflect electricity intensity, the benchmark used in the energy-based allocation should reflect emissions intensity, since the benchmark is facility-specific, rather than an average across all facilities in an industrial sector.

We recommend that the Commission use ARB’s MRR as the data source for electricity purchases, EP, and that emissions factors for IOUs and third

parties should exactly parallel those eventually adopted for the product-based allocation, as discussed in Section 2.3.9.

Equation 12. Historical Emissions Benchmark for an Energy-Based Allocation

$$B_{EP,e} = \sum_{IOU=1}^n (EP_{IOU} \times EF_{IOU}) + \sum_{3rd\ party=1}^n (EP_{3rd\ party} \times EF_{3rd\ party})$$

Where:

“EP_{IOU}” is the historical baseline annual arithmetic mean amount of electricity purchased by the industrial facility from an IOU, measured in MWh, using 2008-2010 MRR data as the historical baseline. Electricity purchases may occur from one or more IOUs, each with its own associated emissions factor.

“EF_{IOU}” is the GHG emissions factor specific to the IOU from which the industrial facility purchased electricity. Each IOU may have its own emissions factor. Emissions factors are discussed at greater length in Section 2.3.9.

“EP_{3rd party}” is the historical baseline annual arithmetic mean amount of electricity purchased by the industrial facility from a third party electricity provider, measured in MWh, using 2008-2010 MRR data as the historical baseline. Electricity purchased by a single facility may occur from one or more third party providers, each with its own associated emissions factor.

“EF_{3rd party}” is the GHG emissions factor specific to the third party electricity provider from which the industrial facility purchased electricity. Each third party may have its own emissions factor. Emissions factors are discussed at greater length in Section 2.3.9 below.

Staff recommends that the historical emissions benchmark for electricity purchases should, in general, use the same 2008-2010 historical period as ARB

used in its direct allocation methodologies. More specifically, we recommend that the historical period for each industrial sector should exactly match the historical period that ARB used when it allocated allowances to address direct emissions.

The definitions of emissions factors, EF, assistance factors, AF, the cap adjustment factor, C, and the dollar conversion factor, D, should be consistent with those of the product-based allocation methodology described in Section 2 and the refinery allocation methodology of Section 4.

3.2. Prospective Energy-Based Allocation

Equation 11 results in an allocation of revenue after costs are incurred; it would allocate revenue for budget year 2013, for example, after the completion of ARB's fourth quarterly allowance auction in November 2013, at which point the dollar conversion factor, D_{2013} , could be calculated. This means that facilities eligible for an energy-based allocation would receive revenue at the end of each year that they have experienced GHG costs in electricity rates. We describe the same dynamic in Section 2.1.3 where we discuss how an "advance" product-based allocation could be implemented relative to an allocation in arrears.

In the case of the energy-based allocation, the timing of the allocation is dependent solely on the completion of ARB's annual allowance auctions rather than the availability of product output data. If the Commission wishes to allocate revenue in advance of costs being incurred, it would need to allocate revenue at the beginning of a program year before the dollar conversion factor for that year would be available. To allocate revenue at the beginning of a year, **Equation 11** would need to make use of a proxy dollar conversion factor and a true up factor in subsequent years, to account for the actual dollar conversion factor once it is

known. The following equation illustrates how an advance energy-based allocation with a true up could be implemented.

Equation 13. Advance Energy-Based Allocation Formula with a True Up

$$A_t = B_{EP,e} \times AF_{a,t} \times C_t \times D_{t-1} + \left(B_{EP,e} \times AF_{a,t-1} \times C_{t-1} \times (D_{t-1} - D_{t-2}) \right)$$

Where:

“t” is the budget year for which revenue is provided to address emissions from electricity purchases, and to which the true-up is added to address emissions that occurred during year t-1.

4. Refinery Allocation Methodology

ARB employs a two-tiered approach to allocating allowances to the refinery sector. First, ARB allocates allowances to the refinery sector as a whole based on a product-based, “simple barrel,” benchmark. This allows the total amount of allowances allocated to the refinery sector to increase or decrease automatically in response to future production levels of refinery products. Second, ARB allocates allowances to individual refineries based on the complexity of the refinery. For simple refineries (i.e. those without a Solomon Energy Intensity Index (EII) value), ARB allocates allowances based on a simple barrel product benchmark methodology, outlined in Equation 14 and Equation 15 below; and for complex refineries (i.e. those that have an EII value), ARB allocates allowances based on a more complex formula that accounts for each refinery’s historical emissions and its relative efficiency compared to other refineries. ARB distinguishes between simple and complex refineries because complex refineries conduct a variety of emissions-intensive processes, and product a variety of products, that would be disadvantaged under the simple barrel metric.

Under the simple-barrel methodology, ARB allocates allowances to individual refineries in a manner that exactly mirrors ARB's product-based methodology; however, ARB limits the amount of allowances each simple refinery can receive to no more than the refinery's average historical emissions adjusted by the refinery assistance factor and the cap adjustment factor.

After allocating allowances to simple refineries, ARB divides the rest of the refinery sector allocation among complex refineries that have a Solomon Energy Efficiency Index value based on the historical emissions of each refinery, an adjustment factor based on the emissions intensity of all complex refineries, and the current emissions for each refinery. The Solomon EII is a complexity-adjusted measurement of energy efficiency developed by Solomon Associates, which maintains an extensive database on global refineries' operations. The Solomon EII is the industry standard for comparing energy efficiency across refineries globally, and California refineries that have a Solomon EII value represent over 90 percent of the refining capacity in the state. Under ARB's approach, and the parallel approach we propose herein, the refinery with the most efficient operations (i.e. the lowest EII value) will receive the greatest portion of allowances.

We propose only two primary changes to ARB's refinery allocation methodology for the purpose of providing revenue to address costs from electricity purchases. The first change affects ARB's benchmark variable, which we modify to account for emissions from electricity purchases, as opposed to direct emissions; and the second change is the introduction of a dollar conversion factor, D , identical to what we propose throughout this document, to convert allowances into dollars. Though ARB's refinery allocation formulas are complex, we believe the benefits of pursuing a comparable methodology to address indirect emissions costs embedded in electricity rates outweigh any

administrative complexity. Any major methodological divergence between ARB’s direct allocation and the Commissions allocation to address indirect costs could potential result in inequities between on-site and off-site CHP.

4.1. Refinery Sector Allocation

Staff recommends that the Commission allocate allowance revenue to the refinery sector based on Equation 14 below, which exactly parallels ARB’s refinery sector allocation methodology. The sole exception is that the benchmark variable in Equation 14, B_{EP} , reflects emissions from electricity purchases rather than direct emissions. For consistency with Section 2.3.7 above, we have expanded upon the original refinery sector allocation formula presented in Appendix A to D.12-12-033 to clarify that the benchmark for electricity purchases should account for the fact that different sources of electricity may have different emission factors.⁵³ We recommend that the refinery allocation formulas should make use of the same emissions factors for electricity purchased from IOUs and third parties that are used in the product-based allocation formulas addressed in Section 2.3.9.

Equation 14. Refinery Sector Allocation

$$SA_{EP,t} = AF_t \times B_{EP} \times C_t \times O_{t-1}$$

Where:

“ $SA_{EP,t}$ ” is the annual allocation to the refining sector for emissions from purchased electricity for budget year t. This variable is in terms of allowances (MTCO₂e).

“ AF_t ” is the assistance factor for budget year t assigned to petroleum refining sector (NAICS Code 324110) as specified in Table 8-1 of ARB’s Cap-and-Trade regulation.

⁵³ We have also made other minor changes to the formula presented in Appendix A to D.12-12-033 to improve clarity, accuracy and consistency with naming conventions throughout this proposal.

“B_{EP}” is the emissions benchmark for electricity purchased for primary products produced by the refining sector. It is determined by the following equation, which we note is identical to the product-based benchmark for electricity purchases defined in Section 2.3.7, Equation 5:⁵⁴

$$B_{EP} = 0.9 \times \frac{\sum_{r=1}^n [\sum_{IOU=1}^u (EP_{r,IOU} \times EF_{IOU}) + \sum_{3rd\ party=1}^p (EP_{r,3rd\ party} \times EF_{3rd\ party})]}{\sum_{r=1}^n Production_r}$$

Where:

0.9 is the benchmark stringency chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities within the sector.

“EP_{r,IOU}” is the total electricity purchased in MWh by industrial facility “r” within the refinery sector from an investor-owned utility. Electricity purchases by a single facility, “r”, may occur from one or more IOU, each with its own associated emission factor. Electricity purchase are summed over n historical period, 2008-2010, using ARB’s MRR data.

“EF_{IOU}” is the GHG emissions factor specific to the investor-owned utility from which the industrial facility “r” purchased electricity. Each IOU may have its own emissions factor. Emissions factors are discussed in Section 2.3.9.

“EP_{r, 3rd party}” is the total electricity purchased in MWh by industrial facility “r” within the refinery sector from a third party electricity provider. Electricity purchases by a single facility “r” may occur from one or more third party providers, each with its own associated emissions factor. Electricity

⁵⁴ It is appropriate to use the benchmark equation in **Equation 5** rather than **Equation 6** in this case because the formula for refinery sector allocation “SA” determines the entire sector’s total allocation rather than an allocation to individual facilities.

purchases are summed over n historical period, 2008-2010, using ARB's MRR data.

" $EF_{3rd\ party}$ " is the GHG emissions factor specific to the third party electricity provider. Each third party may have its own emissions factor. Emissions factors are discussed in Section 2.3.9.

" $Production_r$ " is the total output of primary refinery products produced by industrial facility "r", in the refining sector. Product output is summed over n historical period 2008-2010, using ARB's MRR data.

" C_t " is the cap adjustment factor for budget year "t" assigned to petroleum refining sector. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB's Cap-and-Trade regulation for NAICS Code 324110).

" O_{t-1} " is the output of primary refinery products, in barrels, from the refining sector in year t-1.

Staff recommends that the refinery sector allocations should be granted in advance of costs being incurred, rather than in arrears, just as we have recommended with the product and energy-based allocations. **Equation 14** requires no modification for the 2013 refinery allocation, because it will not be delivered until early 2014; however, for a the 2014 allocation delivered in the first quarter of 2014, the most recent product output data available via MRR will be 2012 data (i.e. "t-2" product output date). For the 2014 refinery allocations, the output variables used in **Equation 14**, **Equation 16**, and **Equation 17** should reflect " O_{t-2} " data.

4.2. Allocation to Facilities Without EII Values (Simple Refineries)

Refineries without an EII value would be allocated revenue based on the following simple barrel benchmark approach, which is equivalent to the product-

based allocation methodology, limited to be no greater than a refinery's historical emissions. The only differences between the following formulas and those used by ARB are the inclusion of benchmarks for electricity purchases, as defined above in Equation 14, and the introduction of a dollar conversion factor.

Equation 15. Revenue Allocation to Individual Refineries without EII Values (Simple Refineries)

$$AR_{X,t} = A_{X,t} \times D_t$$

Where:

"AR_{X,t}" is the allocation of revenue in dollars to an individual refinery "X" for budget year "t".

"D_t" is the dollar conversion factor used to convert metric tons of emissions into dollars. It is the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided. This variable is addressed in more detail in Section 2.6.

Equation 16. If Simple Barrel Method Is Less than Historical Emissions

$$\text{If: } AF_t \times B_{EP} \times C_t \times O_{X,t-1} \leq AF_t \times BE_{EP,X} \times C_t$$

$$\text{Then: } A_{X,t} = AF_t \times B_{EP} \times C_t \times O_{X,t-1}$$

Equation 17. If Simple Barrel Method Exceeds Historical Emissions

$$\text{If: } AF_t \times B_{EP} \times C_t \times O_{X,t-1} \geq AF_t \times BE_{EP,X} \times C_t$$

$$\text{Then: } A_{X,t} = AF_t \times BE_{EP,X} \times C_t$$

Where:

"AF_t" is the assistance factor for budget year t assigned to petroleum refining sector (NAICS Code 324110) as specified in Table 8-1 of ARB's Cap-and-Trade regulation.

“ B_{EP} ” is the emissions benchmark for electricity purchased for primary products produced by the refining sector. This benchmark applies to the refinery sector as a whole, and is not specific to an individual refinery. It is defined in Equation 14 above.

“ C_t ” is the cap adjustment factor for budget year “ t ” assigned to petroleum refining sector. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB’s Cap-and-Trade regulation for NAICS Code 324110).

“ $O_{X,t-1}$ ” is the output of primary refinery products, in barrels, from refinery “ X ” in year $t-1$.

“ $BE_{EP,X}$ ” is the baseline average annual greenhouse gas emissions for purchased electricity for refinery “ X ” over a historical period, 2008-2010, or as determined by ARB Executive Officer. This facility specific benchmark is calculated according to Equation 5 applied to a single facility, rather than a sector as a whole.

4.3. Allocation to Facilities with EII Values (Complex Refineries)

To allocate revenue to refineries that have EII values (i.e. complex refineries) we exactly mirror ARB’s methodology, and we apply the same two changes as in Section 4.2 above to ensure that the benchmark variable accounts for emissions from electricity purchases, not direct emissions, and to convert allowances into dollars. Like the allocation for simple refineries, this methodology makes use of a historical GHG benchmark for electricity purchases, BE_Y , which is specific to each refinery. If a refinery generates all of its electricity on-site and does not purchase electricity, this benchmark will be zero, and therefore the refinery will receive no allocation of revenue.

Equation 18. Revenue Allocation to Individual Refineries with EII Values (Complex Refineries)

$$AR_{Y,t} = BE_Y \times DF_{Y,t} \times F_t \times D_t$$

Where:

"AR_{Y,t}" is the allocation of revenue in dollars to an individual refinery "Y" that has an EII value for budget year "t".

"BE_Y" is the average annual greenhouse gas emissions from purchased electricity for refinery "Y" over a historical period, 2008-2010.

"DF_{Y,t}" is a distribution factor calculated as:

$$DF_{Y,t} = \left((Avg_{EP}/EII_Y) + Adj_{EP,t} \right) / (1 + Adj_{EP,t})$$

Where:

"Avg_{EP}" is the weighted average EII for all facilities with EII values, and is calculated as:

$$Avg_{EP} = \frac{\sum_{Y=1}^n BE_Y}{\sum_{Y=1}^n (BE_Y/EII_Y)}$$

"EII_Y" is the Solomon Energy Intensity Index (EII) for facility "Y" for 2008, 2009 or 2010 as determined to be representative by the ARB's Executive Officer. For the purposes of this calculation, EII values shall be rounded to one digit after the decimal. EII values are to remain confidential to ARB.

"Adj_{EP,t}" is an adjustment factor designed to provide the covered entity with the best EII the most allowances relative to its baseline level:

$$Adj_{EP,t} = \left((Avg_{EP}/EII_{Best}) \times F_t - 1 \right) / (1 - F_t)$$

"EII_{Best}" is the EII of the most efficient covered entity (lowest EII in the sector);

"F_t" is a fraction that adjusts the complex refinery allocation to account for the remaining refinery sector allowances after allocations are made for simple refineries, and is calculated as:

$$F_t = \frac{SA_{EP,t} - \sum_{X=1}^n A_{X,t}}{\sum_{Y=1}^n BE_Y}$$

Where:

“ $SA_{EP,t}$ ” is the annual allocation to the refining sector for emissions from purchased electricity for budget year t , as defined in Equation 14. This variable is in terms of allowances (MTCO_{2e}).

“ $A_{X,t}$ ” is the allocation in terms of allowances (MTCO_{2e}) to simple refinery “ X ” without an EII value for year “ t ”.

“ D_t ” is the dollar conversion factor used to convert metric tons of emissions into dollars. It is the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided. This variable is addressed in more detail in Section 2.6.

The calculations necessary to execute Equation 18 require the use of confidential and proprietary Solomon EII values that ARB cannot share with Energy Division. To implement this calculation in a manner that respects these confidentiality requirements, Energy Division will first calculate each refinery’s benchmark for electricity purchases, BE_Y , using ARB’s MRR data. We will also compute the refinery sector allocation, $SA_{EP,t}$, of Equation 14, and the sum of the revenue allocation to simple refineries without an EII value, $\sum A_{X,t}$, resulting from Equations Equation 16 and Equation 17. We will then communicate these results to ARB, which will enable ARB to calculate the fixed fraction, F_t , and the distribution factor specific to each complex refinery, $DF_{Y,t}$, without having to communicate EII data to Energy Division.

4.4. True-Up Process for Refineries with EII Values

ARB’s refinery allocation methodology employs a true-up for complex refineries that have EII values, and we recommend using a parallel true-up term. The equations below mirror those of ARB’s Cap-and-Trade regulation, making

changes as necessary so ARB's formulas are applicable to emissions from electricity purchases.

If actual 2013 and 2014 emissions from electricity purchase are less than the amount of revenue provided, a true-up will be conducted in 2015 and the facility will need to reimburse the IOU according to the following true-up debit equation:

Equation 19. Refinery True-Up If Actual Emissions Are Less than Revenue Provided

$$\text{If: } (AE_{EP,Y,2013} \times D_{2013}) + (AE_{EP,Y,2014} \times D_{2014}) < AR_{Y,2013} + AR_{Y,2014}$$

$$\text{Then: } AR_{Y,Debit} = 0.8 \times \left[\begin{array}{l} (AE_{EP,Y,2013} \times D_{2013}) + \\ (AE_{EP,Y,2014} \times D_{2014}) - \\ (AR_{Y,2013} + AR_{Y,2014}) \end{array} \right]$$

Where:

"AR_{Y,Debit}" is the allocation of revenue in dollars that individual refinery "Y" must return to the utility.

"AR_{Y,t}" is the allocation of revenue in dollars that individual refinery "Y" received for GHG emissions from electricity purchases experienced in year "t".

"AE_{EP,Y,t}" is refinery "Y's" actual GHG emissions for purchased electricity in year "t." Since actual GHG emission from electricity purchases are difficult to exactly measure in any given year, we propose that these emissions be calculated based on the same fixed emissions factors used throughout this proposal, and discussed in Section 2.3.9. Actual emissions would therefore be estimated according to the following formula:

$$AE_{EP,Y,t} = \sum_{IOU=1}^n (EP_{IOU,t} \times EF_{IOU}) + \sum_{3rd\ party=1}^n (EP_{3rd\ party,t} \times EF_{3rd\ party})$$

Where:

“ $EP_{IOU,t}$ ” is the total electricity purchased in MWh by facility “Y” within the refinery sector from an investor-owned utility during year “t.” Electricity purchases by a single facility, “Y”, may occur from one or more IOU, each with its own associated emission factor.

“ EF_{IOU} ” is the GHG emissions factor specific to the investor-owned utility from which the industrial facility “Y” purchased electricity. Each IOU may have its own emissions factor. Emissions factors are discussed in Section 2.3.9.

“ $EP_{3rd\ party,t}$ ” is the total electricity purchased in MWh by facility “Y” within the refinery sector from a third party electricity provider during year “t.” Electricity purchases by a single facility “Y” may occur from one or more third party providers, each with its own associated emissions factor.

“ $EF_{3rd\ party}$ ” is the GHG emissions factor specific to the third party electricity provider. Each third party may have its own emissions factor. Emissions factors are discussed in Section 2.3.9.

“ D_t ” is the dollar conversion factor applicable to budget year “t.”

If actual 2013 and 2014 emissions from electricity purchase are greater than the amount of revenue provided, a true-up allocation will be conducted in 2015 and the facility will be credited with additional allowance revenue IOU according to the following equation:⁵⁵

⁵⁵ It is unclear to Staff why the structure of the equation in ARB’s credit true-up differs from that of the debit equation; nevertheless, for consistency we maintain ARB’s general approach.

Equation 20. Refinery True-Up If Actual Emissions Are Greater than Revenue Provided

$$\begin{aligned}
 & \text{If: } (2 \times BE_{EP,Y}) < (AE_{EP,Y,2013} + AE_{EP,Y,2014}) \\
 & \text{Then: } AR_{Y,Credit} = \\
 & \quad 0.8 \times \\
 & \quad \left[\frac{(AE_{EP,Y,2013} \times DF_{Y,2013} \times AF_{2013} \times F_{2013} \times D_{2013}) + (AE_{EP,Y,2014} \times DF_{Y,2014} \times AF_{2014} \times F_{2014} \times D_{2014})}{(AR_{Y,2013} + AR_{Y,2014})} \right]
 \end{aligned}$$

“BE_Y” is the average annual greenhouse gas emissions from purchased electricity for refinery “Y” over a historical period, 2008-2010. This value is expressed in Equation 18, and is calculated once at the outset of the program.

“AE_{EP,Y,t}” is refinery “Y’s” actual GHG emissions for purchased electricity in year “t.” Since actual GHG emission from electricity purchases are difficult to exactly measure in any given year, we propose that these emissions be calculated based on the same fixed emissions factors used throughout this proposal, and discussed in Section 2.3.9. Actual emissions would therefore be estimated according to the formula expressed in Equation 19 above.

“DF_{Y,t}” is the distribution factor calculated as in Equation 18.

“AF_t” is the refinery assistance factor for year “t.”

“F_t” is a fraction as calculated in Equation 18.

“D_t” is the dollar conversion factor used to convert metric tons of emissions into dollars.

“AR_{Y,t}” is the allocation of revenue in dollars that individual refinery “Y” received for GHG emissions from electricity purchases experienced in year “t”.

4.5. Second Compliance Period Allocation

The refinery allocation formulas we outline above are applicable to the first compliance period of the Cap-and-Trade program (2013 and 2014). ARB's regulation currently envisions using a Carbon Dioxide Weighted Tonne ("CWT") metric in the second compliance period. This approach would allow ARB to allocate allowances to refineries in a manner that accounts for GHG intensity and the complexity of each refinery, and it would not be dependent on a proprietary index, which would increase the transparency of the allocation methodology. However, ARB is currently evaluating a Complexity Weighted Barrel ("CWB") approach as an alternative to the CWT approach. It is unclear whether and when ARB will develop a new refinery allocation methodology or revise the current methodology. Given the regulatory uncertainty surrounding which refinery allocation methodology will be used in the second and third compliance periods, Staff recommends that the Commission give Energy Division the authority to reevaluate the refinery allocation methodology via a resolution on its own motion if and when ARB modifies the refinery allocation methodology or defines a new methodology to be used during the second and third compliance periods.

5. New Market Entrants and Facility Retirements

The Commission committed in D.12-12-033 to provide allowance revenue to any covered entity or opt-in covered entity that operates in an eligible EITE industry. This includes both existing businesses and new business that may begin operating in California in the future (i.e. new market entrants). The task of developing historical emissions benchmarks for new market entrants poses a particular challenge. Both the energy-based allocation methodology and the refinery allocation methodology make use of facility-specific emissions benchmarks that rely on a 2008-2010 historical period. New market entrants will not have participated in ARB's reporting requirements for these years; therefore,

an alternative methodology is needed to develop historical facility-specific benchmark for these facilities. Staff's understanding is that ARB is currently working on proposals to address this issue. We therefore recommend that the Commission defer action on new market entrants until ARB has addressed this issue in its Cap-and-Trade regulation, at which point the Commission can determine if there is need to revise the energy and refinery allocation methodologuess allocation methodologies.

The Commission must also decide how to treat facilities that cease operations altogether or that no longer engage in an EITE-eligible industrial activity. This issue is only relevant to the energy-based and refinery-based allocations, which depend on facility-specific benchmarks of historical electricity purchases that do not update over time. In contrast, the product-based allocation methodology reflects each facility's annual product output; therefore, if the facility ceases operations, this change will be captured in the facility's annual product output data reported to MRR, and an annual product output of zero units will result in no allocation of revenue.

In the case of the energy-based and refinery allocations, Staff proposes that facilities should no longer receive revenue if they cease operations or if they are no longer primarily dedicated to EITE-eligible industrial activities. We recommend that Staff should work with ARB to identify before each annual allocation which facilities that receive energy-based or refinery allocations have ceased EITE-eligible industrial activities. Staff should then ensure that these facilities do not receive an allocation of revenue unless and until they restart operations.

6. Opt-In EITE Entities

D.12-12-033 currently requires all facilities that operate in sectors eligible for industry assistance and that wish to receive assistance to voluntarily opt-into the Cap-and-Trade program if their emissions levels are less than 25,000 MTCO_{2e}, unless another method can be developed to obtain the information necessary to implement the allocation methodologies.⁵⁶ There are two classes of facilities that are affected by the opt-in requirement: those with emissions between 10,000 MTCO_{2e} and 25,000 MTCO_{2e} that are not covered entities but are nevertheless required to report certain data to ARB; and facilities that have emissions below 10,000 MTCO_{2e}, which currently have no reporting or other requirements under the Cap-and-Trade program.

6.1. Facilities with Emissions between 10,000 and 25,000 MTCO_{2e}

Staff recommends that entities with direct emissions between 10,000 MTCO_{2e} and 25,000 MTCO_{2e} should continue to be required to opt-in to the Cap-and-Trade program in order to be eligible to receive allowance revenue. These entities are already subject to ARB's MRR, and they report verified annual emissions and electricity purchases. However, they are not, at present, required to report annual product output data unless they choose to opt-in to the Cap-and-Trade program. Based on discussions with industrial facilities during the February 14-15, 2013 workshop, Energy Division believes that the additional product output reporting required of opt-in entities would not pose a material administrative or financial burden on such facilities. These facilities already engage in substantial reporting requirements, and they are already required to hire a third party to verify data that they report to ARB. We believe it is reasonable and not unduly burdensome to require these entities to opt-in to the

⁵⁶ D.12-12-033, FOF 58; COL 14

Cap-and-Trade program so that Energy Division can apply the allocation methodologies we propose herein without modification.

We acknowledge that it is possible to implement the energy-based allocation methodology, using ARB's MRR data, without requiring these facilities to opt-in to the Cap-and-Trade program. However, we see little reason why some facilities that have emissions between 10,000 MTCO_{2e} and 25,000 MTCO_{2e} should be required to opt-in to Cap-and-Trade and others should not. Additionally, we believe it would be inequitable and unreasonable to apply the product-based allocation methodology to a covered entity, and to apply the energy-based allocation methodology to a facility in the same industry that happens to have slightly lower levels of emissions than the covered entity.

6.2. Facilities with Emissions below 10,000 MTCO_{2e}

Facilities with direct emissions below 10,000 MTCO_{2e} pose a greater challenge to identify and address in a manner that parallels the three allocation methodologies we outline in this proposal. Facilities with such low-levels of emissions are effectively unknown to ARB – they are not covered by the Cap-and-Trade program, and they are not covered by MRR.

In an attempt to identify how many facilities in eligible EITE industries might emit less than 10,000 MTCO_{2e}, Energy Division requested data from the Large IOUs, which we summarize below in Table 4. Each of the utilities manually classifies its business customers by NAICS Code for reporting purposes to the Commission. These classifications are not independently verified and are made based on the IOU's judgment. To estimate the total number of EITE facilities that operate in IOU service territories, Energy Division requested information about the total number of unique facilities that operate in one of the NAICS codes listed in Table 8- 1 of ARB's Cap-and-Trade regulation. We also

requested total 2012 bundled and unbundled electricity sales associated with these facilities. This data represents the total universe of potentially eligible EITE facilities within IOU territories. We then subtracted the total number of facilities that report to ARB via MRR from the results of our data request – this difference represents the number EITE entities that have direct emission below 10,000 MTCO_{2e}.

The results from this preliminary analysis indicate that by expanding EITE eligibility to facilities that have direct emissions below 10,000 MTCO_{2e}, we would introduce some 8,000 new entities into our revenue allocation methodologies, from an initial group of approximately 100, and we would need to address approximately 50% more GHG emissions associated with electricity purchases. Based on confidential IOU projections of GHG-related costs in 2013, we estimate that approximately 3.3% of total 2013 allowance revenue will be needed to address covered and opt-in eligible EITE entities via the methodologies we outline herein, and that a potential expansion of our program to include facilities with direct emissions less than 10,000 MTCO_{2e} would require a further 1.6% of total allowance revenue.

Table 4. EITE Facilities that Emit Less Than 10,000 MTCO₂e (Estimate)⁵⁷

Distinct EITE Facilities in IOU Territories			Distinct Facilities that Report to ARB (EITEs above 10,000 MT)			Facilities that Emit Below 10,000 MT
Utility	Total EITE Facilities ⁵⁸	Total EITE Consumption (kWh)	Total MRR Facilities	Total MRR Facility Electricity Consumption (kWh)	Total Facilities (Est.)	Total Electricity Consumption (kWh) (Est.)
SDG&E	1,152	203,630,518	2		1,150	
PG&E	5,789	7,942,000,000	66		5,723	
SCE	1,207	4,142,042,000	45		1,162	
Total	8,148	12,287,672,518	113	7,864,011,386	8,035	4,426,661,132

Staff recommends that the Commission should allocate revenue to EITE facilities that have direct emissions below 10,000 MTCO₂e. To do so, the Commission must address three particular issues:

1. How to identify IOU customers that operate in EITE industries and that have less than 10,000 MTCO₂e of direct emissions;
2. How to verify that customers are properly classified in EITE-eligible NACIS Codes.
3. What methodology should be used to allocate allowances to such customers.

6.2.1. Identifying Customers with Direct Emissions below 10,000 MTCO₂e

Similar to the nature of Energy Division's data request, the IOUs could develop an initial list of all customer facilities that they have classified in eligible NAICS codes. Energy Division can then compare this list of customers against ARB's list of entities that report via MRR. Those customers that do not report via MRR have direct emissions below 10,000 MTCO₂e. Eligibility should be based on

⁵⁷ We have temporarily redacted the results of this analysis out of concern that aggregate MRR data may be confidential. We will continue to work with ARB to identify if this data can be shared publicly.

⁵⁸ Facilities represent unique physical locations. For PG&E, this corresponds to "premises" in its billing system; for SCE it corresponds with "service accounts" and "sites"; and for SDG&E it corresponds with "accounts."

a facility basis, which would include all meters associated with a particular facility.

6.2.2. Verifying Customer Classification in EITE NAICS Codes

Based on the initial list of customers that have been classified in EITE-eligible NAICS Codes, Staff recommends that the IOUs conduct outreach to each customer preliminarily identified as EITE-eligible. These customers should then be required to sign an attestation that their facility is primarily engaged in activities described by an EITE-eligible NAICS Code, and IOUs should keep a record of these attestations.

Additionally, since it is possible that IOUs may have mistakenly misclassified customers that should properly be classified in an EITE NAICS Code, customers should have the option to attest that they operate in an EITE industry.

Staff recommends that customers, rather than IOUs, should bear ultimate responsibility for ensuring that a customer's facility is properly classified in an EITE-eligible NAICS Code. However, we recommend that IOUs should be responsible for developing a list of EITE-eligible customers and conducting outreach to these customers to collect attestations and other account-related information. We recommend that the administrative costs for these efforts should be recovered via allowance revenue and should be evaluated and approved in the IOUs' annual applications ordered in D.12-12-033 to review administrative and outreach and education costs.

Given the administrative costs of conducting outreach to approximately 8,000 customers, we recommend that verification of customer classification should only occur once per Cap and Trade program period. For example, this could occur by January 1, 2014, and again by January 1 of 2016 and 2018.

6.2.3. Applicable Allocation Methodology

Though it is possible to collect product output data from each of these customers once they have verified that they operate in EITE-eligible industries, the administrative burden of collecting and verifying this data is non-trivial for customers, IOUs and Staff. In this limited case, unless we later identify an efficient means of collecting verified product-output data from these customers, we believe it is appropriate to deviate from our preference to use the product-based allocation methodology for customers in industries for which ARB has developed a product benchmark. We believe it would be reasonable, instead, to apply the energy-based allocation methodology to EITEs that have direct emissions below 10,000 MTCO_{2e}. Since ARB MRR data are unavailable for these customers, we recommend instead that we use historic 2008-2010 IOU data of a facility's electricity purchases when developing each facility's emissions benchmark. This data should include both IOU and CCA/DA/ESP electricity purchases. The energy-based allocation methodology would otherwise remain unchanged for these facilities.

Since all data necessary to perform the energy-based allocation for these customers is either public or confidential to the IOUs, Staff recommends that the IOUs should be responsible for calculating each eligible facility's allocation based on the energy-based allocation formula's herein, and that this allocation should be delivered as an annual bill credit during the same month as all other EITE credits are delivered to eligible customers. We recommend that IOUs should be required to annually report to Energy Division and/or to the Commission in their annual applications required by D.12-12-033 which customers received this allocation of revenue and in what amount.

7. Small Business Allocation

Decision 12-12-033 allocated allowance revenue to small businesses in compliance with Public Utility Code 748.5 and to provide transition assistance. The intent of providing transition assistance was to ease small businesses into the Cap-and-Trade program and to ensure that small businesses have capital to invest in strategies to reduce their exposure to GHG costs.⁵⁹ The Decision requires utilities to provide this allocation as a volumetric on-bill credit applied to electricity rates that will appear as a separate line-item on small business customers' electricity bills.⁶⁰ Though the Decision recommended that revenue be returned monthly to small businesses, it deferred a final decision on the timing of this distribution to the present implementation phase.⁶¹

To implement this policy, the Commission must determine what compensation rate will be provided to small businesses and how frequently the volumetric return will be provided to customers. For the purpose of this revenue allocation, Decision 12-12-033 defined small business as any non-residential electric customer on a general service or agricultural tariffs whose electrical demand does not exceed 20 kW for more than three months out of the previous 12-month period. The Decision stated that the method used to allocate revenue to small businesses should mirror, to the extent possible, the transition assistance methodologies adopted for EITE customers;⁶² however, it recognized that it is impractical to replicate for small businesses the same product and energy-benchmarking approach that ARB uses when allocating revenue to EITE entities.⁶³ As a result, the Decision recommended a simple allocation formula in Appendix B, which would offset 100% of small businesses' GHG costs in

⁵⁹ D.12-12-033, p. 105; COL 30.

⁶⁰ Ibid, OP 7; FOF 101; COL 32

⁶¹ Ibid, p. 107

⁶² Ibid, FOF 96.

⁶³ Ibid, FOF 97.

electricity rates for the first Cap-and-Trade program compliance period, but would then phase in GHG costs over time through the use of ARB's low leakage risk assistance factor. The intent of the Decision was clearly to phase in GHG costs for small businesses over time, not to entirely eliminate the GHG price signal in small business rates,⁶⁴ and the use of an assistance factor is an effective means to achieve this end. The Decision justified the appropriateness of the low leakage risk assistance factor on the grounds that small businesses pose a relatively lower leakage risk compared to EITE entities, and that for the majority of small businesses in California energy-related costs represent a small fraction of total revenue.⁶⁵

Staff supports the applicability of the low leakage risk assistance factor to small businesses. However, we recommend that the Commission modify D.12-12-033⁶⁶ to apply an alternative, and smoother, declination rate to the small business return. The low leakage risk factor begins at 100% in 2013, declines to 50% in 2015, and declines again to 30% in 2018. In their pre-workshop comments, the Large IOUs recommend that the Commission decline this assistance factor at a rate of 10% a year, from 100% in 2013 to 30% in 2020, as a means of smoothing the rate of decline and avoiding discrete and large changes in transition assistance levels.⁶⁷ It is likely that this approach would result in a small increase in the overall amount of revenue that small business will receive. Nevertheless, we recommend that the Commission modify D.12-12-033 to allow the assistance factor used in the small business allocation methodology to decline 10% annually from 100% in 2013 to 30% in 2020.

⁶⁴ D.12-12-033, FOF 98; FOF 100.

⁶⁵ *Ibid*, p. 104; p. 106;

⁶⁶ Modifications would apply to Finding of Fact 98 and Conclusion of Law 31.

⁶⁷ Large IOUs Pre-Workshop Comments, p. 21.

Though the Decision did not explicitly state that the small business return should occur as a monthly bill credit applied to rates, it clearly envisions that the small business return would affect the GHG price signal in rates,⁶⁸ the implication being that this revenue would be returned as a *monthly* volumetric bill credit. Staff therefore recommends that the small business return should occur as a monthly volumetric bill credit. We believe this approach is in keeping with the language of D.12-12-033 and also presents less administrative complexity than potential alternatives, such as a semi-annual bill credit, which would prove challenging to implement in light of how small businesses eligibility is defined.

Equation 21. Small Business Revenue Allocation

$$AB_{ET,t} = AF_t \times G_{ET,t}$$

Where:

“ $AB_{ET,t}$ ” is the monthly allocation of revenue in dollars per kilowatt-hour to an individual small business that procures electricity service on electrical tariff “ET” during budget year “t.”

“ AF_t ” is the Industry Assistance Factor for the low leakage risk classification defined in Table 8-1 of ARB’s Cap-and-Trade regulation (100%, 50%, and 30% for the first, second and third compliance periods, respectively).

“ G_t ” is the GHG Cap-and-Trade related cost, in dollars per kWh, which is included in a small business customer’s electrical tariff “ET.” This cost is the annual Cap-and-Trade-related cost that each investor-owned utility will incur, and which the ERRA proceeding or the annual applications ordered in D.12-12-033 OP 23 authorizes for recovery in the generation component of rates, that is apportioned to each electrical tariff “ET” via generation cost allocator factors. This cost will therefore vary by utility and by electrical tariff.

⁶⁸ D.12-12-033, p. 107; FOF 100.

The definition of a small business in Decision 12-12-033 provides a straightforward method for utilities to identify entities that are entitled to an allocation of revenue. Therefore, there is no need for additional data reporting from small businesses or in data-transfer from ARB to implement this portion of the Decision. Utilities should evaluate usage for all customers on non-residential tariffs on a monthly basis to determine which are eligible for the small business allocation. These customers will then receive a line-item credit of $AB_{ET,t}$ dollars per kWh for months in which they meet the definition of a small business.

8. Method of Return

The Commission must determine the method by which allowance value should be returned to eligible EITE customers. Though the Commission did not settle this issue in D.12-12-033 for EITE entities, it did provide guidance that revenue should be returned “in a manner that facilitates transparency and customer understanding.”⁶⁹ The Commission has three options: an on-bill credit applied to the delivery component of customers’ bills; an off-bill payment such as a check; or a combination of the two.

8.1. EITE Revenue Return

An on-bill credit is a payment made by the utility that appears as a negative charge on a customer’s bill. While there may be some administrative set-up costs to modify billing systems to handle a new bill credit, these costs are expected to be minimal. The advantage of an on-bill credit over an off-bill credit, in this instance, is that it is likely to be more administratively simple and less costly to implement; it can result in the immediate delivery of value when a

⁶⁹ D.12-12-033, COL 29.

customer receives a bill; and it avoids costs associated with delivering checks to customers.

However, if an on-bill credit is large relative to a customer's monthly bill, the value of the credit could become 'stranded' on the bill, which reduces the value of the credit to the customer and makes it difficult to claim this value without a 'cash-out' provision. This circumstance could occur, for example, for EITE facilities that procure standby service from an IOU, but purchase the vast majority of their electricity from non-IOU third parties, such as off-site CHP facilities. As a result, an EITE facility's monthly IOU bill may be substantially smaller in magnitude than an annual bill-credit.

Staff recommends that an annual on-bill credit be the default method of returning revenue to EITE customers, but that customers be given the option to request a check from the IOU in lieu of receiving an on-bill credit, or to cash out an outstanding bill credit. We recommend that the Commission require IOUs to conduct initial outreach to eligible EITE entities, before the first revenue return, to ensure that eligible EITE entities are aware of their option to request their revenue as a check in lieu of a bill credit.

We also recommend that the on-bill credit should appear on bills with a clear and consistent title across all IOUs, with reasonable variations as necessary to account for character limitations of each IOU's billing system. This title should clearly ascribe the revenue to "California Cap-and-Trade Industrial Assistance." If character limitations prevent this full text from being used, IOUs could alternatively describe the revenue as "CA Cap-and-Trade Industry Assistance" or "CA Industry Assistance." Staff recommends that the IOUs be given some flexibility, with approval by Energy Division, to use a different description if subsequent research by outreach and education consultants suggests better ways of communicating the source and purpose of the revenue allocation. If an EITE

facility requests a check, rather than an on-bill credit, the check should also use similar language, or be accompanied by a clarifying insert, to make it clear that the revenue is part of California's Cap-and-Trade program, not a discretionary allocation made by an IOU. This characterization is necessary both for accuracy and to ensure competitive neutrality between IOUs and other energy service providers.

8.2. Small Business Revenue Return

The Decision has already determined that small businesses will receive their allocation of revenue in the form of a separate line-item, on-bill credit, that must be "applied to the delivery component of the bill to ensure that all customers within a utility's service territory...are treated equally."⁷⁰ However, it did not specify the frequency of this return. As discussed in Section 7, Staff recommends that the small business return occur on a monthly basis.

9. Timing and Implementation of the EITE Return

9.1. Data Requirements

To implement the various allocation methodologies outlined in this proposal, Energy Division and ARB will need to exchange MRR data that facilities report to ARB. We will also need to request new information from covered entities so Energy Division can accurately direct the IOUs to return revenue to specific customer accounts.

We expect that Energy Division will need, at a minimum, access to the following information from ARB, available either via MRR or ARB's internal analyses used to implement its direct allowance allocation:

- A list of industries that received a product-based direct allocation using a best-in-class benchmark;

⁷⁰ Decision 12-12-033, Conclusion of Law 32.

- Historical periods ARB used to calculate direct benchmarks for each industrial activity;
- Relative natural gas use by industrial subsector activity for industries we list in *Table 3. Industrial Sectors with Subsector Benchmarks*.
- Annual electricity purchases by electricity provider for each facility. (Only historical 2008-2010 data are needed for entities that receive a product or energy-based allocation. Historical and the most recent year of electricity purchases are needed to implement the refinery allocation true-up calculation.)
- A list of which refineries have EII values, and which do not.
- The most recent year of product-output data for industries that receive a product-based direct allocation.

In addition to data that ARB already collects or has in its possession, Energy Division will need covered entities to report which primary utility account they wish to have credited with allowance revenue. This information is not currently collected via MRR, but we feel that MRR is the most efficient means of collecting this information on an ongoing basis. We recommend that ARB consider adding to its MRR requirements a new data field that represents the reporting facility's primary electricity account identifier. This data field should be a required input for any facility that qualifies for a direct allocation of GHG allowances from ARB and that is also a customer of one of California's IOUs. Facilities should report the following account-related information, depending on their utility:

- PG&E: Primary Service Agreement Number
- SCE: Primary Service Account Number

- SDG&E: Primary Account Number
- PacifiCorp: Primary Account Number
- CalPeco: Primary Account Number

In a best-case scenario, these regulation changes could be implemented by the end of 2013 during ARB's current cycle of regulation updates planned for 2013, and they could be included in ARB's April 2014 reporting requirement, which would make account-level data available to Energy Division in May or June 2014. However, this data would not be available in time for Energy Division to implement the 2013 revenue allocation and a prospective 2014 allocation, should the Commission choose to allocate revenue in advance of costs being incurred, rather than in arrears. In the interim, Energy Division, ARB or the IOUs will therefore need to communicate directly with each eligible covered entity (approximately 100 facilities) to identify which IOU account they prefer to have credited with revenue.

If ARB is unable to change its MRR requirements to collect this information on an ongoing basis, we recommend that the IOUs should be responsible for contacting each eligible EITE customer in their service territories and recording each customer's preferred primary IOU account number that should be credited with an allocation of revenue. This outreach should be completed before December 1 of each year. If this approach is necessary, by October 1 of each year Energy Division will communicate to each IOU a list of eligible EITE facilities in their territory.

9.2. Timing

Energy Division expects that the most recent year of verified product data will be available in September in each year. Data transfer between Energy Division and ARB will likely occur during October of each year, and final

allocation calculations will be conducted in November after the completion of ARB's fourth quarterly allowance auction. Energy Division will aim to communicate the results of these calculations to the IOUs by December 1 of each year. According to this schedule and the IOUs' expectation that they will need two months to implement the revenue return once Energy Division conveys the necessary information to the IOUs, revenue should be returned to EITE facilities in each utility's February, March or April billing cycles, coincident with the month in which residential customers receive their Climate Dividend. We also note that the first year of implementation could require more time than we currently project, so we recommend that both Energy Division and the IOUs have the ability to seek reasonable extensions if unforeseen implementation challenges arise in 2013 and the first quarter of 2014.

10. Data Confidentiality

In the course of implementing the revenue allocation methodologies outlined in this proposal, the Commission will likely need access to certain confidential data – primarily annual electricity purchases and annual product output that industries report to ARB via MRR. As a general matter, the Commission should treat as confidential any information that industries report to ARB via MRR that ARB treats as confidential.

In addition, there are instances when industries may need to provide confidential data directly to Energy Division if this data is not currently required as part of MRR. For example, to develop subsector benchmarks, as explained in Section 2.3.10, it may be necessary for industries to report electricity use by subsector activity – a data field that is not currently part of MRR and that may reasonably be considered confidential. Such information is not currently afforded

explicit confidentiality guarantees by the Commission. We therefore recommend that the Commission should classify as confidential the following two types of data that may be reported directly to Energy Division: an industrial facility's electricity use, as metered internally or via a utility, and annual product output data.

To ensure that as much data is available to the public and to industries as possible, we recommend that the following information relevant to the revenue allocation methodologies should be made public:

- The dollar conversion factor, D_t , used each year; and
- Product-based emissions benchmarks for electricity purchases associated for each industrial sector (ARB currently publishes its benchmarks in Table 9-1 of its Cap-and-Trade regulation)

Unless facilities consent to its disclosure, in cases where only one or two facilities operate in an industrial activity, product-based benchmarks for these industrial activities should remain confidential to protect potentially confidential information that could be discoverable to each facility if benchmarks were to be published.

Additionally, Energy Division will need to make certain information available to the IOUs so they will be able to deliver revenue to the appropriate utility accounts or to a facility's assigned contact. To this end, Energy Division will communicate the following information to IOUs once each year:

- The primary service account number, or other account-related identifying information, that eligible EITE entities have provided to Energy Division to designate which account they would like credited with revenue;

- The primary contact information of a representative of the EITE facility that should receive the facility's allocation of revenue, if the facility elects to receive a check;
- The dollar amount of revenue that should be returned to each facility for a given Cap-and-Trade budget year.

11. Eligibility of Departing Load Customers

In D.12-12-033, the Commission committed to treating EITE facilities similarly, "regardless of whether the EITE entity purchases or consumes electricity from its own CHP facility, a third-party owned CHP facility, or from an investor-owned utility or DA provider."⁷¹ The Decision also acknowledged guidance provided in ARB's Cap and Trade regulation that "allowance revenue shall be used exclusively for the benefit of retail ratepayers of the electrical distribution utility."⁷² Given the Commission's policy preferences and limitations placed on the use of allowance revenue, it may be necessary to clarify that certain types of EITE facilities that self-generate electricity or purchase electricity entirely from off-site generators are eligible for an allocation of allowance revenue.

There are different classes of facilities that Staff believes should be reasonably considered retail IOU customers for the purpose of determining an EITE facility's eligibility for an allocation of GHG allowance revenue authorized in D.12-12-033. These include the facilities with the following characteristics:

- Facilities that are bundled electricity customers of IOUs – they purchase both electricity supply and delivery from the IOU;

⁷¹ D.12-12-033, COL 27.

⁷² 17 CCR §95892(a)

- Facilities that are electricity customers of CCAs/DAs/ESPs – they are unbundled IOU customers that procure electricity supply from a CCA/DA/ESP and electricity delivery from an IOU;
- Facilities that make use of distributed generation, including CHP, from resources located on-site or off-site, and that also procure standby electricity service from the interconnecting IOU;
- Facilities that use distributed generation to supply 100% of their electricity demand and that pay departing load charges to an IOU, but that do not procure standby service from an IOU.

Facilities that purchase bundled, unbundled, or standby service from an IOU receive electricity service under a tariff approved by the Commission, and they can reasonably be understood to be retail IOU customers. Facilities that either self-generate or procure 100% of their electricity from off-site generation resources may not procure actual electricity service from an IOU, but they may pay nonbypassable departing load charges, including the Public Purpose Program (PPP) Charge, Nuclear Decommissioning Charges, and other charges associated with historic IOU investments in grid assets or programs established by the Commission that have broad public benefits. EITE facilities that pay only departing load charges to an IOU, and that do not procure electricity service from an IOU, should nevertheless be eligible for an allocation of revenue afforded by D.12-12-033.

ARB's direct allocation of allowances to IOUs took into consideration emissions associated with CCA/DA/ESP customers as well as self-generation, qualifying facilities, and other resources not controlled by IOUs but that directly serve customers in IOUs' service territories. Therefore, the allowance allocation to IOU ratepayers accounted for emissions from facilities in IOU service territories that procure electricity supply from non-IOUs and that may also

procure electricity delivery from non-IOWs, such as from off-site CHP facilities. Such facilities would be required to pay departing load charges, but they may not have a need or requirement to procure standby service from the interconnecting IOU. ARB's allocation of allowances accounted for facilities that self-generate and that procure electricity directly from off-site generators, and as a matter of fairness they should also qualify for an allocation of revenue.

As a matter of policy, it would be contrary to the stated intent of D.12-12-033 if EITE facilities that paid only departing load charges to IOUs were not eligible to qualify for an allocation of revenue. Such facilities will receive a direct allocation of allowances from ARB, and they must also receive an allocation of revenue from the Commission to address outstanding leakage risk associated with emissions from electricity purchases, whether those purchases are from an IOU or a non-IOU electricity provider.

12. Miscellaneous Issues

12.1. EITE Customers Spanning Multiple IOU Service Territories

It is possible for a single EITE facility to span more than one IOU territory, and for a single facility to purchase electricity from more than one IOU. In such cases, the EITE facility should receive allowance revenue from each IOU in proportion to the amount of electricity that the facility purchases from electricity providers in each IOU's territory. However, for administrative simplicity depending on the limitations of MRR data, Staff recommends that it would also be appropriate to apportion revenue from each IOU in proportion to the facility's purchases from each IOU. For example, if a facility purchased 30% of its total electricity from PG&E, 50% from SCE, and the remaining 20% from a DA provider, $\frac{3}{8}$ (37.5%) of the revenue due to the facility would be paid by PG&E allowance revenue, and $\frac{5}{8}$ (62.5%) would be paid by SCE.

Appendix A – Final Proposed Product-Based Allocation Methodology

A.1 Product-Based Allocation Equation

Equation 22. Product-Based Allocation Formula for Prospective Allocation

$$Allocation_{b,t} = \left(\sum_{a=1}^n (O_{a,t-2} \times B_{EP,a} \times AF_{a,t} \times C_{a,t} \times D_{t-1}) \right) \times EF_{b,initial} + Trueup_{b,t}$$

Where:

“a” is an eligible industrial activity defined in Table 9-1 of ARB’s Cap and Trade regulation

“b” is an individual industrial facility that operates in industrial activity “a.”

“t” is the budget year for which the Commission is allocating revenue.

“ $O_{a,t-2}$ ” is the total production output in year “t-2” from a given industrial activity at a given facility subject to the product-based benchmark. We address the data source for this output variable and the need to true-up this variable in Section 2.5.

“ $B_{EP,a}$ ” is the indirect emissions benchmark for industrial activity “a” in terms of MTCO_{2e} of emissions from electricity purchases per unit output for the applicable sector. The emissions benchmark for electricity purchases is calculated by summing, across all entities in industrial sector “a”, indirect emissions from electricity purchases, and then dividing this amount by total production output for the industrial activity. The exact formula used to calculate this benchmark for each industrial activity is discussed in Section 2.3.

“ $AF_{a,t}$ ” is the “assistance factor” for budget year “t” assigned to a given industrial activity “a.” Assistance factors for each industrial activity are specified in Table 8-1 of ARB’s Cap-and-Trade regulation. The assistance factor is the percent of the emissions

benchmark (described in Section 2.2) that will be provided in an allocation, ranging from 100% to 30%. The specific percentage is tied to ARB's determination of an industrial sector's leakage risk and the year for which the allocation is being sought.

" $C_{a,t}$ " is the cap adjustment factor for budget year "t" assigned to each industrial activity "a". The cap adjustment factor represents the decline in the overall GHG cap. The schedule for the cap adjustment factor can be found in Table 9-2 of ARB's Cap-and-Trade regulation. We address the cap adjustment factor in greater length in Section 2.4.

" D_{t-1} " is the Dollar Conversion Factor calculated based on the sales-weighted average market clearing price of allowances sold at auction of the same vintage as the compliance year for which compensation is being provided. This variable is addressed in more detail in Section 2.6.

" $EF_{b,initial}$ " is the emissions factor in $MTCO_2e/MWh$ specific to industrial facility "b" during an "initial" year, as defined below in Equation 24. This emissions factor will vary for each year "t" according to the source of facility "b's" mix of electricity purchases as well as each source's own emission factor, as discussed in Section 2.3.9.

A.2 Electricity Intensity Benchmark Equation

Equation 23. Electricity Intensity Benchmark Equation for a Product-Based Allocation

$$B_{EP,a} = 0.9 \times \frac{\sum_{b=1}^n (\sum_{IOU=1}^u EP_{b,IOU} + \sum_{3rd\ party=1}^p EP_{b,3rd\ party})}{\sum_{b=1}^n Production_b}$$

Where:

" $B_{EP,a}$ " is the electricity intensity benchmark for industrial activity "a" in units of MWh per product output.

“b” is an individual industrial facility that operates in industrial activity “a” outlined in Table 9-1 of ARB’s Cap and Trade regulation.

0.9 is a benchmark stringency factor chosen to reflect the emissions intensity of highly efficient, low-emitting covered entities for each industrial activity. For sectors in which there is only one covered entity or in which no covered entity is at least as efficient as the benchmark, 0.9 is not used and instead the benchmark is set based on the “best-in-class” value (i.e. the emissions intensity of the most GHG-efficient California facility).

“ $EP_{b, IOU}$ ” is the total electricity purchased in MWh by industrial facility “b” from an IOU. Electricity purchases by a single facility “b” may occur from one or more IOUs, each with its own associated emission factor. Electricity purchases are summed over a historical period, 2008-2010, using ARB’s MRR data.

“ $EP_{b, 3rd\ party}$ ” is the total electricity purchased in MWh by industrial facility “b” from a third party electricity provider. Electricity purchases by a single facility “b” may occur from one or more third party providers, each with its own associated emissions factor. Electricity purchases are summed over a historical period, 2008-2010, using ARB’s MRR data.

“ $Production_b$ ” is the total output, produced by industrial facility “b”, for the industrial activity for which the benchmark is being calculated. Product output is summed over an historical period 2008-2010, using ARB’s MRR data.

A.3 Industrial Facility-Specific Weighted Average Emissions Factor

Equation 24. Industrial Facility-Specific Weighted Average Emissions Factor

$$EF_{b,t} = \frac{\sum_{provider=1}^n (EP_{b,provider,t} \times EF_{provider,t})}{\sum_{provider=1}^n EP_{b,provider,t}}$$

Where:

“b” is an individual industrial facility that operates in industrial activity “a” outlined in Table 9-1 of ARB’s Cap and Trade regulation.

“ $EP_{b, provider, t}$ ” is the total electricity purchased in MWh by industrial facility “b” from each electricity provider in year “t,” as reported in ARB’s MRR data.

“ $EF_{provider, t}$ ” is the GHG emissions factor specific to each electricity provider from which the industrial facility “b” purchased electricity. Each provider has its own emissions factor, as discussed in Section 2.3.9.

Equation 25. Initial Industrial Facility-Specific Weighted Average Emissions Factor

$$EF_{b, initial} = \frac{\sum_{provider=1}^n (EP_{b, provider, initial} \times EF_{provider, initial})}{\sum_{provider=1}^n EP_{b, provider, initial}}$$

Where:

“ $EP_{b, provider, initial}$ ” is the most recent year of ARB MRR data about total electricity purchased in MWh by industrial facility “b” from each electricity provider. For an allocation that addresses GHG costs incurred in budget year “t,” the most recent year of verified MRR data would be year “t-2.”

“ $EF_{provider, initial}$ ” is the GHG emissions factor specific to each electricity provider from which the industrial facility “b” purchased electricity, as discussed in Section 2.3.9, based on the most recent year of public data of annual utility sales at the time the allocation is granted. Public data for both POU and IOU sales for budget year “t” will be available in year “t+2.”

A.4 True-Up Term for a Prospective Allocation

True-ups correct for the allocation of two-year's prior.

Equation 26. True-Up Term for a Prospective Allocation

$$Trueup_{b,t} = \left(\sum_{a=1}^n (AF_{a,t-2} \times B_{EP,a} \times C_{a,t-2} \times [(O_{a,t-2} \times D_{t-2}) - (O_{a,t-4} \times D_{t-3})]) \right) \times (EF_{b,trueup} - EF_{b,initial})$$

Where:

" $EF_{b,trueup}$ " is calculated according to Equation 24 once actual MRR data and utility sales data for year "t-2" are available.

A.5 Illustrative Formulas for 2013 Allocation

The allocation to address 2013 costs will occur between February and April 2014, at which point ARB will have verified data about each facility's 2012 product output and all 2013 allowance auctions will be complete. There will be no true-up term for the 2013 allocation. However, the 2013 allocation will itself be trued up in the 2015 allocation, once verified 2013 product output data is available.

$$Allocation_{b,2013} = \left(\sum_{a=1}^n (O_{a,2012} \times B_{EP,a} \times AF_{a,2013} \times C_{a,2013} \times D_{2013}) \right) \times EF_{b,initial}$$

When this allocation occurs in early 2014, ARB will also have verified data about each entity's electricity purchases for 2012. The facility's initial emissions factor will therefore reflect 2012 electricity purchases. When the facility's allocation is trued-up in 2015, the *trueup* emissions factor will reflect 2013 purchases.

$$EF_{b,initial} = \frac{\sum_{provider=1}^n (EP_{b,provider,2012} \times EF_{provider,2013})}{\sum_{provider=1}^n EP_{b,provider,2012}}$$

A.6 Illustrative Formula for 2014 Allocation

The 2014 allocation will also not include a true-up term. This allocation will be trued-up in the 2016 allocation, after actual verified product output data for 2014 is available in September 2015.

$$Allocation_{b,2014} = \left(\sum_{a=1}^n (O_{a,2012} \times B_{EP,a} \times AF_{a,2014} \times C_{a,2014} \times D_{2013}) \right) \times EF_{b,initial}$$

The actual amount of revenue granted to facilities in 2014 will be the sum of $Allocation_{b,2013}$ and $Allocation_{b,2014}$.

A.7 Illustrative Formula for 2015 Allocation

$$Allocation_{b,2015} = \left(\sum_{a=1}^n (O_{a,2013} \times B_{EP,a} \times AF_{a,2015} \times C_{a,2015} \times D_{2014}) \right) \times EF_{b,initial} + Trueup_{b,2015}$$

The true-up term in the 2015 allocation corrects for the 2013 allocation and is somewhat atypical because 2012 product output data was used in 2013, and the dollar conversion factor does not need to be trued up.

$$Trueup_{b,2015} = \left(\sum_{a=1}^n (AF_{a,2013} \times B_{EP,a} \times C_{a,2013} \times [(O_{a,2013} \times D_{2013}) - (O_{a,2012} \times D_{2013})]) \right) \times (EF_{b,trueup} - EF_{b,initial})$$

And,

$$EF_{b,trueup} = \frac{\sum_{provider=1}^n (EP_{b,provider,2013} \times EF_{provider,2013})}{\sum_{provider=1}^n EP_{b,provider,2013}}$$

A.8 Illustrative Formulas for 2016 and Subsequent Years

The allocation formulas for 2016 and all subsequent years will exactly follow the default formulas and will require no modifications. As an example, we illustrate the allocation formula and true up term for the 2016 allocation.

$$Allocation_{b,2016} = \left(\sum_{a=1}^n (O_{a,2014} \times B_{EP,a} \times AF_{a,2016} \times C_{a,2016} \times D_{2015}) \right) \times EF_{b,initial} + Trueup_{b,2016}$$

$$Trueup_{b,2016} = \left(\sum_{a=1}^n (AF_{a,2014} \times B_{EP,a} \times C_{a,2014} \times [(O_{a,2014} \times D_{2014}) - (O_{a,2012} \times D_{2013})]) \right) \times (EF_{b,trueup} - EF_{b,initial})$$

$$EF_{b,initial} = \frac{\sum_{provider=1}^n (EP_{b,provider,2012} \times EF_{provider,2014})}{\sum_{provider=1}^n EP_{b,provider,2012}}$$

$$EF_{b,trueup} = \frac{\sum_{provider=1}^n (EP_{b,provider,2014} \times EF_{provider,2014})}{\sum_{provider=1}^n EP_{b,provider,2014}}$$

Depending on the source of retail sales data used to calculate the provider-specific emissions factor, $EF_{provider}$, the provider-specific emissions factor used in the initial and trueup calculations of each EITE facility's emissions factor may be different. The trueup term will properly capture any differences.

Appendix B – Illustration of Perverse Outcome of Emissions Intensity Benchmark

In the following example, an industry is composed of two California facilities that produce exactly the same amount of product in a given year (1,000 units). Assume that they also produced the same amount of product over a historical period 2008 to 2010. One facility is more efficient than the other – it requires only 90 MWh of electricity to produce its products, while its competitor requires 110 MWh of electricity. To illustrate the perverse outcome, we assume that the inefficient facility operates in PG&E’s territory, which according to Option A in Table 2 of this document has an emissions factor of 0.291 MTCO₂e/MWh. The efficient facility operates in SCE’s territory, which has a higher emissions factor of 0.387 MTCO₂e/MWh.

If we calculate the industry benchmark according to Equation 5, which yields an emissions intensity benchmark that averages IOU emissions across a sector, the industry’s product benchmark is 33.42 MTCO₂e per unit of product output.

The calculations below illustrate that under this approach, the efficient facility is undercompensated for its actual GHG costs, while the inefficient facility receives a windfall – a perverse outcome.

Actual Costs Incurred							
	Energy Intensity (MWh/units of product)	Product Output (units)	Electricity Purchases (MWh)	IOU Emissions Factor (MT/MWh)	Actual Electricity Emissions (MT)	Carbon Price (\$/MT)	Actual GHG Costs (\$)
PG&E Facility	110	1000	110000	0.291	\$32,010	\$14	\$448,140
SCE Facility	90	1000	90000	0.387	\$34,830	\$14	\$487,620

GHG Revenue Allocation Granted							
	Product Output (units)	Industry Benchmark (MT/units of product)	Emissions Credited (MT)	Carbon Price (\$/MT)	Revenue Allocation (\$)	Actual GHG Costs (\$)	Revenue Gain (Loss) (\$)
PG&E Facility	1,000	33.42	33420	\$14.00	\$467,880	\$448,140	\$19,740
SCE Facility	1,000	33.42	33420	\$14.00	\$467,880	\$487,620	(\$19,740)