Decision 14-10-033 October 16, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of Southern California Edison Company (U338E) for Approval of Greenhouse Gas Cap-and-Trade Program Cost and Revenue Allocation.	Application 13-08-002 (Filed August 1, 2013)
And Related Matters.	Application 13-08-003 Application 13-08-005 Application 13-08-007 Application 13-08-008

PHASE 2 DECISION ADOPTING STANDARD PROCEDURES FOR ELECTRIC UTILITIES TO FILE GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION REQUESTS

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PHASE 2 DECISION ADOPTING STANDARD PROCEDURES FOR ELECTRIC UTILITIES TO FILE GREENHOUSE GAS FORECAST REVENUE AND RECONCILIATION REQUESTS

Summary

In accordance with California Public Utilities Code Section 748.5, California Global Warming Solutions Act of 2006, Assembly Bill 32 (AB 32),[1] and Decision 12-12-033, this decision adopts standard procedures for electric utilities to use when filing greenhouse gas (GHG) revenue allowance and reconciliation applications. Pursuant to AB 32, certain electric utilities must participate in a cap-and-trade program designed by the California Air Resources Board (ARB) to reduce GHG emissions. The state allocates allowances to these electric utilities on behalf of ratepayers and the utilities are required to sell the allowances at ARB's quarterly auctions, with all value from such sale accruing for the benefit of electric ratepayers. Pursuant to Section 748.5 of the California Public Utilities Code, the utilities are required to return revenues from the sale of allowances to customers in a specified manner and to annually forecast how much allowance revenue ratepayers will receive.

This decision applies to five electric utilities: Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, PacifiCorp, an Oregon Company and Liberty Utilities (CalPeco Electric) LLC. This decision adopts methodologies for calculating forecast GHG allowance revenue and GHG costs, as well as recorded GHG allowance revenue and GHG costs.

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1 Statutes of 2006, Chapter 488, which established California Health and Safety Codes § 38500-38599.

This decision adopts Confidentiality Protocols for cap-and-trade related data and requires the five utilities to use a proxy price in their forecasts.

This decision requires each of the five utilities to file its GHG revenue and reconciliation application annually, and, if applicable, as part of its Energy Resource Recovery Account or Energy Cost Adjustment Clause forecast application.

1. Background

Pursuant to the California Global Warming Solutions Act of 2006, Assembly Bill (AB) 32, the California Air Resources Board (ARB) designed a statewide greenhouse gas (GHG) cap-and-trade program.[2] The cap-and-trade program creates an economy-wide cap on major sources of GHG emissions, including power plants, fuel suppliers and industrial facilities.

Rulemaking (R.) 11-03-012 addresses GHG-related costs and allowance revenues for the five electric utilities. Decision (D.) 12-12-033 in R.11-03-012 required five electric utilities to file applications for approval of forecast GHG costs and revenues, including administrative and customer outreach expenses, sufficient to calculate the amount of GHG allowance revenue that should be returned to customers in 2014. The five utilities are the three large utilities (Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E) and the two small utilities (PacifiCorp, an Oregon Company (PacifiCorp) and Liberty Utilities (CalPeco Electric) LLC (Liberty)).

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[2] California Cap and Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Title 17, California Code of Regulations (CCR), § 95801.

Although Energy Resource Recovery Account (ERRA) and Energy Cost Adjustment Clause (ECAC) forecast proceedings[3] already examine the electric utilities' forecast procurement costs for the purpose of ensuring recovery of costs associated with fuel and purchased power, the Commission reasoned that, in the early years of the cap-and-trade program, it would be prudent to take a "more comprehensive and detailed approach" to evaluating GHG costs and allowance revenues.[4] Thus, D.12-12-033 requires the utilities to file annual applications, separate from ERRA and ECAC, to request approval of GHG-related forecasts. The approved cap-and-trade related forecasts would then be included in the next year's rates. In the same application, the utilities must reconcile recorded GHG costs and allowance revenue amounts with forecasts from prior years. These forecast revenue and reconciliation (FR&R) applications are referred to in this decision generally as "GHG FR&R applications." The GHG FR&R applications filed in August 2013 and addressed in the Phase 1 decision are referred to herein as the "2014 GHG Revenue Forecast Applications." For purposes of GHG FR&R applications and requests, "reconciliation" refers to true-up performed for the purpose of incorporating the revenue return (including the California Climate Credit) into rates. It is not the same as the reconciliation performed for the three large utilities for procurement cost recovery purposes in their respective ERRA proceedings.

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[3] The three large utilities have regularly scheduled annual ERRA forecast proceedings. The two small utilities have ECAC proceedings. PacifiCorp files normally files a Total ECAC Adjustment applications with the Commission on or before August 1 of each year.

[4] D.12-12-033 at 147.

1.1. GHG Allowance Revenue Waterfall

As required by D.12-12-033, the electric utilities must forecast both GHG costs and allowance revenues. Utilities incur GHG costs both by directly purchasing compliance instruments for their own emissions compliance obligation under the cap-and-trade program, and, indirectly, through GHG cap-and-trade costs embedded in the price of wholesale electricity. For the three large utilities, these GHG costs are incorporated into the generation component of electricity rates through the ERRA process. Incorporating the costs into rates results in a carbon price signal intended to incent an overall decrease in energy consumption and reduction in GHG emissions.

The state allocates GHG allowances to utilities on behalf of ratepayers. The utilities act as an intermediary by holding and then selling the allowances for ratepayer benefit; ARB prohibits the electric utilities from using the allowances for their own compliance obligation or for their own benefit. The revenue from the sale of these GHG allowances is then returned to ratepayers and helps to offset the increases in electricity costs that result from GHG compliance. D.12-12-033 sets forth the details of the revenue return contemplated by statute.

Each year, to forecast the amount of allowance revenue that each utility will return to customers for the next year, the following amounts must be calculated:

1. **Forecast Allowance Revenues**. These are the revenues received by a utility as a result of selling the allowances allocated to ratepayers by the state.
2. **Forecast Administrative and Customer Outreach Expenses**. These are the costs incurred by a utility for administrative and customer outreach expenditures that relate to the allowance revenue return program.

3. **Forecast Set Aside for Incremental Energy Efficiency (EE) and Clean Energy Programs**. D.12-12-033 allows utilities to set aside a portion of allowance revenues to fund EE and clean energy programs that have been approved by the Commission in other proceedings.

4. **Forecast Emissions-Intensive and Trade-Exposed emissions (EITE) Customer Return**. Using methodologies being developed in R.11-03-012, a portion of allowance revenues are returned to customers who qualify as EITE.[5] The EITE customer return is based on formulas and made once per year.

5. **Forecast Small Businesses Return**. Using a methodology adopted in R.11-03-012, a portion of allowance revenues are returned to customers who meet the definition of small business developed in R.11-03-012.[6] The Forecast Small Business Return is volumetric; it is calculated using the Forecast GHG Cost (*see* Item 8 below) and the volume of electricity used by the customer and is returned as a credit to the delivery component of the customer's monthly bill.

6. **Forecast Residential Return**. The residential rate return only applies to electricity usage above Tier 2. The residential rate return is volumetric; it is calculated based on the Forecast GHG Cost (*see* Item 8 below) and the volume of electricity used by the customer. It is returned as an offset to the delivery rate component, but does not appear on the customer's monthly bill.[7]

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[5] D.12-12-033 sets forth an overview of the proposed methodology sufficient for purposes of forecasting the EITE return. Future decisions in R.11-03-012 are expected to provide additional direction.

[6] D.12-12-033 sets forth an overview of the methodology sufficient for purposes of forecasting the small business customer return for 2014. D.13-12-002 adopted a specific methodology.

[7] The two small utilities have not had caps imposed on their baseline rates and thus have not experienced the large disparities between lower and upper tiers that the large utilities have. Because they are able to pass GHG costs on to both lower and upper tiers, D.12-12-033

Footnote continued on next page

7. **Forecast California Climate Credit**. The Climate Credit is distributed to residential households after all the above expenses and customer returns have been made. It appears as a credit on the customer's bill twice per year.[8] The Climate Credit is not related to the volume of electricity used by the household: each household within a utility's territory receives the same Climate Credit.

8. **Forecast GHG Costs**. These are the GHG emissions costs incurred directly or indirectly by a utility as a result of the GHG cap-and-trade program. Direct costs include, generally, the costs incurred to purchase compliance instruments[9] for plants run by the utility or the cost of providing physical or financial settlement specifically for GHG emissions from plants not owned or operated by the utility. Indirect costs generally reflect GHG costs embedded in the price of power purchased on the market or through contracts that do not include GHG settlement terms. ***In this proceeding, the sole purpose of the Forecast GHG Costs is to calculate the Forecast Small Business Return and the Forecast Residential Return above.***

Once these forecasts are approved, the utility may include them in electric tariff schedules by following the required or authorized advice letter (AL)

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required the small utilities to make their residential returns solely through the Climate Credit. For the large utilities, the Commission authorized this rate offset until such time as the differences between lower and upper-tier residential rates can be substantially reduced or eliminated. The Commission is currently considering this issue in R.12-06-013.

[8] The California Climate Credit received its official name in April 2014 by ruling in R.11-03-012. Prior to that time it was referred to as the "Climate Dividend."

[9] A covered entity must surrender one compliance instrument for each metric ton of carbon dioxide (CO_2) equivalent of GHG emissions for its compliance obligations. Allowances and offsets are the two types of compliance instruments in the cap-and-trade program. (California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Title 17, CCR (Cap-and-Trade Regulations), § 95856.) The regulation also limits the use of offsets to no more than 8% of compliance instruments in a compliance period. (Title 17 CCR § 95854.)

procedures. At the end of the year, the utility must then report the recorded[10] amounts and reconcile them with the forecast return already made to customers. Any surplus or shortage is applied to the upcoming forecast revenue return.[11]

2. Procedural History

Pursuant to D.12-12-033, the utilities filed their 2014 GHG Revenue Forecast Applications on August 1, 2013.

On October 4, 2013, the assigned Commissioner and assigned Administrative Law Judge (ALJ) issued a Scoping Memo and Ruling (Phase 1 Scoping Memo) that created a Phase 1 and Phase 2 for these consolidated proceedings and set forth the scope of issues to be resolved in Phase 1. Phase 1 focused on adopting GHG program forecast costs and revenues for 2014. Phase 2 was to focus on standardizing procedures for future GHG FR&R applications. On December 27, 2013, D.13-12-041 was issued for Phase 1, adopting GHG program costs and allowance revenue forecasts for incorporation into 2014 electricity rates.

On January 2, 2014, the assigned ALJ issued an e-mail ruling that set a prehearing conference (PHC) date and invited the parties to prepare PHC Statements. On January 10, 2014, PHC Statements were filed by SDG&E, Liberty, and the Office of Ratepayer Advocates (ORA). The Phase 2 PHC was held on January 14, 2014. At the Phase 2 PHC, the parties noted the importance of

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10 We use the term "recorded" to describe both the actual cost and revenue amounts recorded, and the estimate of indirect GHG costs embedded in electricity prices. The methodology for calculating these indirect costs is discussed later in this decision.

11 The details of this reconciliation process are discussed later in this decision.

keeping accounting requirements consistent with existing practices developed in the ERRA proceedings.

On February 19, 2014, the assigned Commissioner and assigned ALJ issued a Scoping Memo and Ruling (Phase 2 Scoping Memo) that set forth the procedural schedule and scope of Phase 2 of these consolidated proceedings.

As set forth in the Phase 2 Scoping Memo, the issues to be addressed in Phase 2 are:

1. Should a proxy GHG price be used for forecasting GHG allowance costs and revenues? If so, how should the proxy GHG allowance price be calculated?
2. What general methodological guidelines should the utilities follow to forecast total annual GHG costs (direct and indirect costs) and allowance revenues, and should these forecasts be public?
3. How should the utilities true up actual GHG costs and revenues against forecasts and account for differences in future revenue allocations?
4. Do the Confidentiality Protocols promote transparency while ensuring compliance with ARB regulations and adequately protecting proprietary utility information? Do the protocols provide an adequate framework to define what types of information should be public?
5. What information should future GHG Revenue and Reconciliation Applications include? For example, does the Supplemental Information Sheet form used in Phase 1 provide sufficient information for evaluation of future forecasts or are additional standardized reporting guidelines necessary?
6. What are the appropriate steps for utilities to seek approval to use or set aside allowance revenue for an EE or clean energy program?
7. What steps should be taken to ensure that the GHG Revenue and Reconciliation Applications filed in 2014 and

2015 are efficiently and reasonably coordinated with ERRA Forecast Proceedings and ECAC proceedings?

8. What accounting procedures and rules should each utility follow to report its GHG costs, allowance revenues and compliance instruments inventory? Are there accounting and reporting requirements used or being developed in ERRA or ECAC proceedings that should be adopted in this proceeding? Are the accounting and reporting requirements that have been proposed in this proceeding consistent with the accounting and reporting requirements in the ERRA and ECAC proceedings?
9. What safety considerations are raised by the GHG Revenue and Reconciliation Applications?

Pursuant to the Phase 2 Scoping Memo, on March 25, 2014, the five utilities served a joint utility proposal (Initial Joint Utility Proposal) addressing many of the scoped issues for Phase 2. On April 4, 2014, the "Large Users"[12] served comments on the Initial Joint Utility Proposal. On April 8, 2014, the utilities held a workshop for stakeholders to discuss the Initial Joint Utility Proposal. Following the workshop, on April 29, 2014, the five utilities filed a Revised Joint Utility Proposal, Workshop Summary, and Joint Stipulations (Revised Joint Utility Proposal). The Revised Joint Utility Proposal included an extensive summary of the Initial Joint Utility Proposal and workshop discussions. The portions of the Revised Joint Utility Proposal that contain the final joint stipulations are attached as Attachment A and are annotated to reference relevant portions of this decision (Joint Stipulations).

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[12] The Large Users include the California Large Energy Consumers Association, the California Manufacturing and Technology Association and the Energy Producers and Users Coalition. (Initial Comments of Large Users on March 25, 2014 Joint Utility Proposal at 1.)

By e-mail ruling on March 10, 2014, the assigned ALJ supplemented the record with the California ARB position on Cap-and-Trade Program and Confidentiality in Public Utility Commission Proceedings, dated February 19, 2014 (ARB Confidentiality Memo).

On May 13, 2014, ORA filed a Phase 2 Opening Brief and the utilities filed a Joint Utility Opening Brief. On May 20, 2014, SCE and SDG&E filed separate reply briefs.

The record was reopened on August 28, 2014 to allow parties to comment on a methodology for calculating weighted average cost (WAC) of GHG compliance instruments. PG&E, SCE and SDG&E filed opening briefs on September 4, 2014, and ORA and PG&E filed reply briefs on September 8, 2014.

3. Forecast Year Revenue and Costs

3.1. Proxy GHG Allowance Price for Forecast

Given the need to keep information related to GHG allowance prices and bid strategies confidential in accordance with ARB regulations, the ARB Confidentiality Memo recommended that a proxy price be used to forecast the price of allowances. Parties generally agreed with this approach, and at the workshop several different methodologies for calculating a proxy price were developed.

The proxy price has several advantages. By using a proxy price for revenue and cost forecasts, public understanding of the investor-owned utilities (IOUs) costs and revenues associated with participation in the cap-and-trade program can be facilitated and transparency of the costs and revenues will be increased. At the same time, the confidential information of the utilities regarding allowance consignment and procurement strategies, and the actual prices paid, will be protected.

There are a number of indices that could be used to set a proxy price. This proceeding considered several methods for calculating the proxy price including:

- Using the daily settlement price of the Intercontinental Exchange (ICE) allowance futures contract with a vintage year equal to the forecast year and delivery in December of the forecast year.
- Using the average of the four prior ARB auction settlement prices.

For consistency, we are adopting use of ICE allowance futures contracts for the vintage year equal to the forecast year with delivery in December of the forecast year. Although the utilities are required to use the ICE index, each utility would set its own Forecast Proxy Price using a methodology consistent with its ERRA or ECAC methodology for calculating forward prices for other commodities.[13] For example, PG&E currently uses a five-day trading range for forward electric and natural gas prices in its ERRA.[14] The same five-day range would be used to calculate the Forecast Proxy Price. Liberty, in contrast, does not file an ECAC application every year. When filing a GHG FR&R application without a corresponding ECAC, the utility should simply calculate the Forecast Proxy Price using a reasonable methodology based on the forward ICE settlement prices and explain that methodology. Thus, even though each utility will use forward ICE settlement prices for their forecast, the proxy prices may not be identical across utilities.

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[13] Joint Utility Proposal at 4.

[14] *Id.* at 3.

To ensure maximum usefulness of the information collected for GHG FR&R applications, the Forecast Proxy Price must be calculated each year and made available to the public as part of the application process.

The ORA supports the above approach for calculating the Forecast Proxy Price.[15] The approach is reasonable and meets the confidentiality needs and the transparency goals of the parties, ARB and the Commission.

3.2. Forecast Allowance Revenue

Forecast Allowance Revenue is calculated by multiplying the Forecast Proxy Price by that year's allocation of GHG allowances allocated on behalf of ratepayers. This allocation is public and is explained in ARB's Cap-and-Trade Regulation.[16] The forecast revenue must also take into account interest and franchise fees and uncollectibles if applicable.

3.3. Forecast Direct Costs and Indirect Costs

Each utility uses its own model to forecast how it expects to dispatch its portfolio and participate in markets. The utilities use these models to forecast their overall procurement costs in their respective ERRA and ECAC proceedings. These same models and forecasts can be used to calculate forecasts of both direct and indirect GHG emissions, as well as costs.

A reasonably accurate forecast of GHG emission costs is important for setting rates sufficient to cover procurement costs. For purposes of ERRA and ECAC forecast proceedings, the forecast cost of GHG compliance is one element included in the calculation of overall procurement costs. For purposes of

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[15] ORA Phase 2 Opening Brief at 1.

[16] *See* 17 CCR § 95892(a).

calculating the GHG revenue returns, the Forecast GHG Cost is used to calculate the volumetric revenue returns made to small business and residential customers.

Forecast direct costs should be calculated by multiplying the Forecast Proxy Price (as described above) by the number of allowances the utility expects it will need to cover its forecast direct emissions. This approach was included in the Revised Joint Proposal and was supported by ORA.[17] We find that this approach allows for a reasonable estimate of forecast direct costs.

Forecast direct emissions are those emissions for which a utility expects to be responsible for the costs under the cap-and-trade program. These emissions are associated with generation owned by the utilities and contracted generation for which the utility is responsible for allowance costs.[18] ARB provides methodologies for calculating emissions from different sources applicable to the electric utilities' portfolios. When filing its GHG FR&R application, the utility must describe the methodology used to forecast direct emissions in detail sufficient for interested parties to understand and the Commission to determine whether the methodology was reasonable and consistent with Commission and state policies and law.

Utilities should have the option to report emissions from financially settled tolling agreements as either direct or indirect costs. In such agreements the utility has a financial responsibility for a known amount of emissions at a specified price, thus these costs bear similarity to emissions for which the utility

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[17] ORA Opening Brief at 1.

[18] Specifically, these direct costs include forecasts emissions for utility owned generation, and imports, tolls and other contracts for which the utility is responsible for GHG costs.

has a physical compliance obligation, but the utility does not have a physical compliance obligation for these emissions, thus they also bear similarity to indirect costs. This information will allow interested parties and the Commission to better evaluate the total emissions for which the utility has responsibility, while allowing the utility flexibility.

PacifiCorp is the only multi-jurisdictional retail provider (MJRP) in California. ARB's Mandatory Reporting Regulation[19] specifies a formula for MJRPs to use to calculate the emissions associated with serving their retail load. It is reasonable for PacifiCorp to report MJRP emissions as its sole category of direct GHG emissions.

For indirect costs (the GHG costs embedded in the price of market purchases),[20] we must rely on estimates for both the amount of emissions and the cost of compliance instruments for those emissions. Financially settled contracts that embed the cost of GHG compliance in the energy for these resources, such as financially settled qualifying facility contracts, should be categorized as indirect GHG costs. The utility must make the estimations using a reasonable methodology that is consistent with D.12-12-033, the utility's own ERRA or ECAC filing, and any applicable ARB cap-and-trade program rules.

This approach is reasonable and provides sufficient transparency. ORA supports the approach described above.[21] No party objected.

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19 17 CCR 9511(b)(4).

20 Note that in ERRA the utilities include indirect GHG costs in the total cost of energy purchases, so the indirect cost of compliance has not, to date, been presented as a separate calculation or subset of procurement costs. Estimated indirect GHG costs are only used for calculating the allowance revenue returns to customers.

21 ORA Phase 2 Opening Brief at 2.

When filing its FR&R application, the utility must describe the methodology used in detail sufficient for interested parties to understand and for the Commission to determine whether the methodology was reasonable and consistent with Commission and state policies and law.

3.4. Use of Proprietary Models

PG&E proposes to use its own proprietary Market Data System (MDS) model for forecasting the price per ton of GHG emissions that is used when forecasting direct GHG costs in its ERRA proceeding.[22] PG&E proposed to use this same confidential forecast of GHG allowance prices, rather than the public Forecast Proxy Price addressed above, when forecasting direct GHG costs in both its ERRA and its GHG FR&R applications. PG&E argues that its own model is already part of its procurement forecast in its ERRA forecast application. This proprietary forecast, however, would need to remain confidential to protect PG&E's market position or auction participation strategies from disclosure. For consistency with ERRA, the Commission finds it reasonable to allow PG&E to use its proprietary GHG allowance price forecast, rather than the Forecast Proxy Price, when it forecasts direct GHG costs. In order to provide transparency and a tool for comparison of GHG costs, PG&E must also provide a public illustrative total GHG cost forecast, including illustrative rate impacts by tariff schedule, using the approved Forecast Proxy Price to calculate forecast direct GHG costs.

This illustrative total GHG cost forecast is for informational purposes only. If PG&E chooses to use its confidential allowance price forecast, PG&E's forecast volumetric residential and small business returns should be based on the actual

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[22] Joint Utility Proposal at 5 and 8. The other utilities did not raise the issue of using proprietary GHG allowance price forecasts in their ERRA or ECAC proceedings.

GHG cost forecast that PG&E seeks to include in rates, not on PG&E's illustrative total GHG cost forecast. This ensures that PG&E's revenue allocations meet the requirements and intent of D.12-12-033 that volumetric revenue allocations are defined in relation to the actual volumetric costs in rates.

PG&E and other parties noted that if there is a large discrepancy between the cost forecast by the MDS model and the cost forecast using the Forecast Proxy Price, PG&E should seek to revise its GHG proxy price calculation.[23] We therefore direct PG&E to include in the public version of its application a statement as to whether the disparity between the two forecasts was more or less than 5%.

3.5. Forecast Administrative and Outreach Expenses

The GHG FR&R application must also include a reasonable forecast of administrative and outreach expenses related to the program for the next year. This forecast should only include expenses that are in addition to administrative and outreach expenses that have been authorized in other rate cases. Utilities must provide a narrative to support the itemized forecast expenses. The narrative should detail the anticipated activities and how they are central to the GHG allowance revenue program established by D.12-12-033 and subsequent decisions about the program's implementation.

4. Recorded Year Revenue and Costs

4.1. Recorded Year Allowance Revenue

Utilities are required to sell all their allocated allowances at auction for the year issued, but the utilities have discretion to decide the number of allowances

[23] ORA at 3.

to sell at each auction within the year. The recorded revenue from the sale of these allowances is the sum of each auction's clearing price multiplied by the number of allowances the utility auctioned. The details of reconciling recorded year allowance revenue with the forecast year are discussed later in this decision.

4.2. Recorded Year Direct and Indirect GHG Costs

4.2.1. Recorded Year Direct GHG Costs

The recorded direct GHG costs include two variables: (a) total direct emissions and (b) costs of compliance instruments purchased to satisfy this liability. Recorded year direct GHG costs represent the actual costs for utility owned generation and imports, tolls and other contracts for which the utility has responsibility for cap-and-trade costs.[24]

Direct emissions should be calculated on an annual basis based on monthly dispatched resources using methodologies consistent with the ARB regulations for measuring GHG emissions.[25] This approach is supported by the utilities and ORA and is consistent with the approved Joint Implementation Plan.[26] When calculating recorded year direct GHG costs, the utilities must include all emissions for the year, even if they have not yet purchased or surrendered compliance instruments for that exact quantity of emissions.

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[24] The specific terms of a utility's contract may specify whether the utility provides physical compensation (a transfer of compliance instruments) or financial compensation (payment to the entity for the cost of the applicable compliance instruments) for the cap-and-trade costs. Physical settlement is a direct cost, but the utilities can choose to report financially settled tolling agreements as direct or indirect costs. Financially settled qualifying facility contracts where the financial obligation is embedded in the market price of energy purchases or within the specific contract terms for energy payment may be categorized as indirect GHG costs.

[25] Revised Joint Utility Proposal at 12.

[26] Approved by D.13-12-003, in R.11-03-012.

The cost of compliance instruments is more difficult to estimate because the utilities do not have to surrender the full amount of compliance instruments for a given year until the end of the compliance period. During this time, the price for compliance instruments is expected to change.

All allowances are designated with a "vintage year." The vintage year corresponds to the California GHG Allowance Budget year from which the allowance came.[27] The budget is the "cap" in cap-and-trade. The number of allowances available of a certain vintage is equal to that year's cap. As shown in the table below, an entity may bank allowances from previous vintage years, but not borrow from future vintage years,[28] to meet a compliance obligation.

ARB Table of Eligible Allowance Vintages by Compliance Period

Table 3.2 Eligible Allowance Vintages for Annual and Triennial Compliance Obligations			
First Compliance Period			
Covered Emissions Year	**Compliance Obligation Due Date**	**Percent of Compliance Obligation Due**	**Eligible Vintages of Allowances**
2013	November 1, 2014	30% of 2013 covered emissions	Vintage 2013 only
2014	November 1, 2015	70% of 2013 and 100% of 2014 covered emissions	Vintages 2013 and 2014, any combination
Second Compliance Period			
2015	November 1, 2016	30% of 2015 covered emissions	Vintages 2013-2015, any combination
2016	November 1, 2017	30% of 2016 covered emissions	Vintages 2013-2016, any combination
2017	November 1, 2018	70% of 2015 and 2016, and 100% of 2017 covered emissions	Vintages 2013-2017, any combination
Third Compliance Period			
2018	November 1, 2019	30% of 2018 covered emissions	Vintages 2013-2018, any combination
2019	November 1, 2020	30% of 2019 covered emissions	Vintages 2013- 2019, any combination
2020	November 1, 2021	70% of 2018 and 2019, and 100% of 2020 covered emissions	Vintages 2013-2020, any combination

[27] 17 CCR § 95841.

[28] ARB allows certain exceptions for allowances purchased from the allowance price containment reserve. (*See* 17 CCR §95913.)

(Source: CARB Regulatory Guidance Document, at 8.)

SDG&E proposed that if there was a surplus of compliance instruments available, the cost should be calculated using a weighted average cost of "the vintage year allowances and offsets (up to 8%) expected to be used to satisfy the emissions liability."[29] SDG&E also proposed that the ICE index price be used if there was a shortage of compliance instruments in inventory.[30]

In briefs, parties were supportive of using a WAC, but were not in agreement about the methodology.

PG&E supported a WAC calculated using the WAC of compliance instruments held by the applicable utility that are valid for the current cap-and-trade compliance period. They also agreed that offsets that are eligible to be surrendered for the compliance period should be included.[31] SDG&E proposed a methodology that calculates WAC based on vintage year, not compliance period.[32] ORA supports using the WAC methodology and, like SDG&E, argues that WAC should be separated by vintage year.[33]

We see no reason to limit WAC to a specific vintage year. In addition, there are compelling reasons to set a value based on all allowances held that could be used in the compliance period. For example, if a utility is holding

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[29] Revised Joint Utility Proposal at 11; Opening Brief of SDG&E on Methodology for Determining Weighted Average Cost of Compliance Instruments.

[30] *Id.*

[31] PG&E Reply Brief Addressing Methodology for Calculating and Recording Direct Greenhouse Gas Compliance Costs at 1.

[32] Opening Brief of SDG&E on Methodology for Determining Weighted Average Cost of Compliance Instruments.

[33] ORA Reply Brief Regarding Methodology for Recorded Year Direct GHG Costs at 2.

vintage year 2013 and 2014 allowances in 2014, it can bank both of them. For 2014, the WAC would include both the 2013 and 2014 allowances. For 2015, the WAC would include vintage year 2015 allowances, and any remaining vintage year 2013 and 2014.[34]

Furthermore, Commission rules allow utilities to purchase compliance instruments to meet a portion of expected future compliance costs. Due to ratepayer equity concerns, it would be inappropriate to consider expenses to satisfy future emission obligations as current-year GHG costs for the purpose of calculating GHG revenue returns or establishing GHG costs in rates. As a result, it is reasonable and equitable to use the WAC of all compliance instruments in utility inventory that are valid for the current compliance period as a measure of the costs associated with direct emissions incurred each month.

Using a WAC of all eligible compliance instruments is more transparent and easier to understand than a WAC based on vintage year.

In comments to the proposed decision, ORA argued that the WAC should be based on allowance vintage year and not compliance period. ORA correctly points out that some allowances are not eligible for the entire compliance period. For example, the allowances surrendered in 2013 must be vintage 2013 allowances. ORA argues that a WAC calculation based on compliance period would therefore not be accurate, but ORA fails to acknowledge that a WAC by vintage year is also an approximation. Absolute accuracy is not possible when determining the cost of compliance for a single year of a compliance period. Utilities are not required to turn in all compliance instruments on annual basis.

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[34] *See* Section 7.6 of this decision for a detailed description of compliance periods.

Rather, the utility may turn in a portion of the allowances required for a given year and then hold the remaining allowances (or wait to acquire them) until the end of the compliance period. Because of this, we must rely on estimates to determine what the annual cost would have been if the utility had turned in all compliance instruments at the end of the year instead of waiting until the end of the compliance period. As discussed above, we believe that calculating this estimate using WAC based on the value of compliance instruments eligible for the entire compliance period will provide the most accurate and least volatile proxy for actual annual compliance cost.

Attachment C sets forth the WAC methodology for use by all utilities. This methodology is generally the same as the one that parties commented on in their September 2014 briefs, but it has been revised for clarity based on party comments. Under this methodology, the WAC should be calculated using each month's emissions multiplied by the WAC of eligible compliance instruments held at that point in time. The calculation considers:

1. Eligible compliance instruments, which include all allowance vintages eligible for the current compliance period and all valid offsets;
2. Monthly average of eligible compliance instruments; and
3. If compliance instruments are sold, the WAC does not change, but if compliance instruments are bought, the WAC could change.

Under this methodology, a utility's recorded direct GHG costs for each month shall be calculated as follows:

$$Direct\ GHG\ Costs_{month} = WAC \times Direct\ Emissions\ Quantity_{month}$$

Where:

"WAC" is the weighted average cost of all compliance instruments held in inventory that are eligible for that cap-and-trade compliance period.[35]

"Direct Emissions Quantity" is the direct emissions for the entire month calculated in accordance with ARB standards, regardless of whether compliance instruments have been surrendered for these emissions. The emissions quantity is updated on at least a quarterly basis based on best available information.

When filing its GHG FR&R application, the utility must describe the methodology used to make these calculations in detail sufficient for interested parties to understand and the Commission to determine whether the methodology was reasonable and consistent with Commission and state policies and law.

SCE proposes that for tolling agreements under which the utility is obligated to financially compensate the tolling counterparty for GHG costs, the WAC is not an appropriate estimate of the settling price.[36] Instead SCE proposes that for these tolling agreements the monthly ICE settlement price be used to

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[35] For example, when recording 2014 costs a utility shall calculate its WAC based on its inventory of all offsets and allowances with vintage years 2013 and 2014. Any allowances with vintage year 2015 will not be calculated in the WAC used for recording 2014 costs since the second compliance year begins in 2015. When recording 2015 costs, a utility shall calculate its WAC based on its inventory of all offsets and allowances with vintage years 2015, 2016 and 2017, plus any 2013 or 2014 allowances or offsets not used to meet its obligation in the first compliance period.

[36] SCE Opening Brief Regarding Methodology for Recorded Year Direct GHG Costs at 2.

forecast the costs of financial settlement. We agree that this approach is reasonable for financially settled tolling agreements or other agreements where the GHG costs are financially settled, where the utility's inventory of compliance instruments will not be relevant. We also confirm that, because the source of the GHG emissions is known, tolling agreements in which GHG costs are financially settled can be categorized as direct GHG costs. For these financially settled contracts the quantity of direct emissions should be excluded from the formula above that calculates the cost of direct GHG emissions using the WAC. To calculate the direct GHG costs of tolling or other agreements with financial settlement of GHG costs, utilities may add to Attachment C a separate line showing the calculation of direct GHG costs using the following formula:

> Direct Cost = Settlement Price x Emissions Quantity
>
> Where:
>
> "Settlement Price" is the unit price at which the utility will financially compensate its tolling counterparty for GHG; usually the ARB Auction Clearing Price; and
>
> "Emissions Quantity" is the emissions obligation for the entire month calculated in accordance with the tolling agreement.

4.2.2. Recorded Year Indirect GHG Costs

As with the forecast of indirect GHG costs, the recorded year indirect cost must rely on estimates of both emissions and the cost per ton associated with those emissions. These estimates must be reasonable and consistent with ARB and Commission guidance.[37]

[37] Note that for ERRA and ECAC, indirect GHG costs are not reported separately from total procurement costs.

Several approaches were suggested for calculating the price of indirect emissions: (1) the average ICE price over the last year; (2) the sales weighted average price of four ARB auction clearing prices of the last year; or (3) the average of the daily published prices of the California Independent System Operator (CAISO) GHG Allowance Price Index. Of these, use of the CAISO GHG price index is the most reasonable and useful.

The CAISO GHG allowance price index is the average of daily trade prices provided by industry sources. Currently, CAISO sources from at least two providers (ICE, and CME Group and/or Argus).[38] The CAISO GHG allowance price index is relied on by other entities, is readily available, and is intended to represent the daily allowance prices that bidders rely upon when they participate in CAISO's wholesale markets. For purposes of GHG FR&R applications, utilities should use the annual average of CAISO's daily GHG Allowance Price Index computed by averaging the published daily price for the recorded year and dividing by the number of days in that year.

Using the CAISO GHG price index was supported by ORA. The utilities did not have a consistent proposal, but did support CAISO index as a possible measure. Thus the indirect cost should be calculated as follows:

> Recorded Indirect GHG Costs = CAISO Proxy Price x Estimated Indirect GHG-Emissions
>
> *Where*:
>
> "CAISO Proxy Price" is the annual average of the CAISO GHG Allowance Price Index for the current year.

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[38] CAISO describes the methodology of determining its daily GHG Allowance Price Index. Business Practice Manual for Market Instruments, Attachment K. http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market%20Instruments.

> "Estimated Indirect GHG Emissions" is the utility's estimated actual annual emissions associated with wholesale market electricity purchases and contracts that do not have a specific provision for settlement of GHG costs. Emissions shall be calculated in a manner consistent with Attachment D to this decision.

When filing its GHG FR&R application, the utility must describe the methodology used to make these calculations in detail sufficient for interested parties to understand and the Commission to determine whether the methodology was reasonable and consistent with Commission and state policies and law.

4.3. Recorded Administrative and Customer Outreach Expenses

Actual administrative and outreach expenses should be recorded in the applicable GHG memorandum accounts. The amounts expended are subject to reasonableness review as part of the reconciliation portion of GHG FR&R applications. In GHG FR&R applications, or in future ERRA or ECAC applications where these costs may be considered, utilities should itemize and substantiate administrative and outreach expenses in detail sufficient for parties and the Commission to evaluate the reasonableness of these expenses.

5. Clean Energy and Energy Efficiency Projects

The law allows the Commission to allocate up to 15% of the GHG allowance revenues for clean energy and energy efficiency (EE) projects.[39] To be

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[39] "The commission may allocate up to 15% of the revenues, including any accrued interest, received by an electrical corporation as a result of the direct allocation of greenhouse gas allowances to electrical distribution utilities pursuant to subdivision (b) of Section 95890 of Title 17 of the California Code of Regulations, for clean energy and energy efficiency projects

Footnote continued on next page

eligible, projects must: (a) be established pursuant to statute, (b) be administered by the electrical corporation, and (c) not be otherwise funded.[40]

D.12-12-033 set forth the basic steps to determine if a project is eligible:

> **Step 1**: Seek and receive approval in relevant proceedings where EE or clean energy programs are being comprehensively reviewed;
>
> **Step 2**: Use approval to modify GHG revenue balancing account tariff sheets, as necessary, to allow approved funding amount to be disbursed and recovered;
>
> **Step 3**: Include approved funding amount in the next, and future GHG Revenue Reconciliation Application.[41]

D.12-12-033 further required that GHG emissions reduction be a stated and measurable goal of any proposed project.[42]

At this time, none of the utilities have completed the first step-approval of clean energy and EE projects in accordance with D.12-12-033. SDG&E, however, seeks clarity on how to request funds and how to ensure that funds from the forecast year will be available once an investment has been approved.

Because approved investments in clean energy or EE projects will reduce the Climate Credit paid to ratepayers, it is important that spending for clean energy or EE projects be authorized before any revenue is set aside. Generally, for an EE or clean energy program to be approved, there must be certainty regarding the funding source. This leads to a potential chicken-and-egg

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established pursuant to statute that are administered by the electrical corporation and that are not otherwise funded by another funding source." (Public Utilities Code Section 745(c).)

[40] *Id.*

[41] D.12-12-033 at 135.

[42] *Id.*

problem, where the project is unlikely to be approved without an identified funding source, but no funds can be set aside until a project has been approved.

To resolve this dilemma, we require the utilities to report in their GHG FR&R applications the forecast maximum amount of allowance revenue that other proceedings can appropriate for clean energy and EE projects in a given year. The allowance revenue appropriated for clean energy and EE projects shall be included in the GHG FR&R application only when funding for such projects has been previously approved by the Commission. When seeking approval to use GHG allowance revenue for clean energy and EE projects, the utilities should use the following procedure:

(1) As part of the FR&R application, a utility should forecast the amount of allowance revenue that other proceedings can appropriate for clean energy and EE projects (the Forecast Clean Energy Amount). The existence of the Forecast Clean Energy Amount will demonstrate that funds are available for qualified projects (Clean Energy Projects) to be approved in other proceedings.

(2) When seeking approval of a project, the utility should include the following in its request: (a) explain why the project qualifies under Section 748.5(c), (b) explain why the project is best funded using GHG allowance revenues instead of ordinary recovery through rates, and (c) reference the Forecast Clean Energy Amount.

(3) If a project is subsequently approved and the utility has authority to track recorded expenses in an appropriate balancing account, these expenses should be reflected and reconciled in the utility's next GHG FR&R application.

(4) Funds used for Clean Energy Projects are still subject to any reasonableness reviews required as part of the project approval and the Forecast Clean Energy Amount must still be reconciled against the recorded allowance revenues, but the Clean Energy Project funds are otherwise unencumbered.

6. Coordination with ERRA and ECAC; Fourth Quarter Updates

6.1. Coordination with ERRA and ECAC

Forecast ERRA and ECAC are proceedings to review forecast procurement costs for inclusion in rates. Each of the three large utilities files an annual ERRA forecast application. Liberty files an application by July 1 for changes to the ECAC billing factors, but only files in the event that its total ECAC revenues change by 5% in either direction.[43] PacifiCorp files its ECAC adjustment application by August 1 of each year.[44] A significant portion of the GHG FR&R analysis involves determining forecast GHG costs; these forecast procurement costs are also evaluated in forecast ERRA and ECAC proceedings.

Historically, the three large utilities have filed their ERRA forecast applications at very different times of the year with the result that not all of the ERRA applications could be approved by year end. In 2014, all three large utilities filed their ERRA applications earlier in the year with the goal of including the forecast procurement cost in rates at the start of 2015.

D.12-12-033 required that the utilities file GHG FR&R applications separately from their corresponding ERRA/ECAC proceeding. By requiring this separate filing, the Commission and stakeholders were able to closely evaluate the utilities' methodologies and forecasts for GHG costs and allowance revenues.

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[43] California Pacific Electric Company, LLC, Energy Cost Adjustment Clause Tariff Sheet. January 1, 2013. http://www.libertyutilities.com/west/documents/rates/PreliminaryStatement_6.pdf.

[44] Pacific Power & Light Company. Energy Cost Adjustment Clause Tariff Rate Rider, December 10, 2011. https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/California/Approved_Tariffs/Rate_Schedules/Energy_Cost_Adjustment_Clause_Tariff_Rate_Rider.pdf.

With the issuance of this decision, the utilities will have sufficient direction on how to forecast, estimate and reconcile the cap-and-trade related amounts, and thus there is no longer a need to have the utilities file applications separately from ERRA or ECAC. With the issuance of this decision finalizing the process and standards for review of GHG FR&R applications, it is no longer necessary to keep the GHG allowance analysis separate from the annual ERRA forecast applications.

Therefore, beginning in 2015 with forecasts for 2016, each utility shall file its GHG FR&R request as a separate chapter or part of its ERRA or ECAC forecast application.[45]

To make this procedure work efficiently and fairly, and to allow sufficient review of the forecast and recorded amounts, we note that the following must be included within the GHG FR&R application:

- Completed forms from Attachment C (Calculation of WAC Form) and Attachment D (GHG Revenue and Reconciliation Application Form), with details on the methodologies used.
- If the utility uses a proprietary model to determine GHG procurement costs for ERRA, the utility can continue to do so, but must also provide an illustrative forecast cost using the proxy price (as described in Section 4.1 above).
- Unless otherwise directed, each utility should update its GHG FR&R filing on November 1 to include third quarter information. (See below for detailed list of information to be updated.)

[45] In the event that a utility does not file an annual ECAC application, the GHG FR&R application can be filed separately.

- If a forecast ERRA or ECAC application is not filed in a given year, then the FR&R request should be filed as a separate application by no later than August 1.

In the event that the GHG FR&R application has not been adopted by year end, the utility shall use the adopted amounts for the then-current year to calculate revenue returns until the application has been ruled on. This will allow the revenue return to ratepayers to continue without interruption.

6.2. Fourth Quarter Update

Unless otherwise directed by the assigned ALJ or assigned Commissioner in their ERRA or ECAC proceeding, each of the three large utilities should refresh its GHG FR&R request no later than November 15 to reflect new information. Ideally, this update should coincide with other updates to the utility's ERRA forecast proceeding, and therefore utilities should expect that rulings in future applications may require a Fourth Quarter Update to be filed prior to November 15. The due date for the Fourth Quarter Update in 2014, however, will be November 1 or such other date as the ALJ in the utility's 2014 GHG FR&R application may direct. As detailed in the table below, updates should be made to both forecast and recorded costs. It is expected that the update will be made too early to include information from the November ARB allowance auction.

For several reasons, the two small utilities, PacifiCorp and Liberty, are not required to file Fourth Quarter Updates. First, these two utilities file their GHG FR&R applications late in the year so that an update would only cover a few months at most. Second, because of the size of these two utilities and the type of information required to be filed, we do not expect a Fourth Quarter Update to result in significant new information. Finally, requiring these two small utilities to complete a Fourth Quarter Update would be an administrative burden for the utilities that would be passed on to their ratepayers. However, the ALJs presiding over these FR&R applications appropriately have discretion to require updated filings at any time.

The Fourth Quarter Update is an important informational tool for interested parties and the Commission to understand the changes that have occurred. The update should include a narrative to explain any significant or unusual changes. The modeling methodology used in the Fourth Quarter Update must be consistent with the modeling methodology used in the original application. The Fourth Quarter Update should also be used to adjust the amounts to be incorporated into the forecast year's rates.

As discussed in the next section, the Fourth Quarter Update may, upon approval of the Commission, also be used to incorporate recorded overcollection or undercollection of costs from the current year into rates for the following year. The purpose of the Fourth Quarter Update is to increase the accuracy of the estimated GHG allowance revenue return calculation for the next year. In contrast, for purposes of cost recovery, GHG costs are treated like any other procurement costs.

Table of Information to be Updated in Fourth Quarter Update

Filing Year	**Forecast Year**
Recorded Allowance Revenues through Q3	Updated Forecast Allowance Revenue
Forecast Allowance Revenue for Q4	
Recorded GHG Costs through Q3	Updated Forecast GHG Costs
Forecast GHG Cost for Q4	
Recorded Administrative & Customer Outreach Expenses through Q3	Updated Forecast Administrative & Customer Outreach Expenses

Filing Year	Forecast Year
Forecast Administrative & Customer Outreach Expenses for Q4	
Recorded amount of Clean Energy investments in approved projects made through Q3	Updated amount available for approved Clean Energy investments in Forecast Year
Forecast Clean Energy investments in approved projects for Q4	
Recorded EITE Customer Return, Forecast Small Business Return, and Forecast Residential Return through Q3	Updated Forecast EITE Customer Return, Forecast Small Business Return, and Forecast Residential Return,
Forecast EITE Customer Return, Forecast Small Business Return, and Forecast Residential Return for Q4	
Recorded Climate Credit	Updated forecast Climate Credit

7. Reconciliation

7.1. Establishment of Balancing Accounts and Memorandum Accounts

D.12-12-033 directed the utilities to create ratemaking accounts to track and record GHG-related costs and revenues.[46] These were created in 2013 through the AL process.[47] Ordering Paragraphs 16 and 17 of D.12-12-033 directed the utilities to set aside GHG revenues for outreach and administrative expenses in advance of distributing GHG revenues to customers.[48] Any amount

[46] D.12-12-033 at Ordering Paragraph (OP) 20, OP 16, OP 17.

[47] SCE AL 2841-E, PG&E AL 4181-E and AL 4168-E, SDG&E AL 2452-E, PacifiCorp AL 484-E and AL 485-E, Liberty AL 25-E.

[48] D.12-12-033 at OP 16-17.

left in the outreach expense or administrative expense memo account was directed to be rolled over to the subsequent year.[49]

Table of Balancing and Memorandum Accounts Established to Track GHG-Related Costs and Revenues

	SCE	PG&E	SDG&E	PacifiCorp	Liberty
GHG Costs (ERRA Sub-account)	GHG Cost Sub-Balancing Account in ERRA	Sub-balancing account in ERRA	GHG costs sub-balancing account in ERRA	GHG Allowance Costs Sub-balancing Account	GHG sub-balancing account in GHG Balancing Account
GHG Revenues	GHG Revenue Balancing Account	GHG Revenue Balancing Account	GHG Revenue Balancing Account	GHG Allowance Revenue Balancing Account	GHG Revenue Balancing Account
Outreach Expenses	GHG Customer Outreach and Education Memo Account	Greenhouse Gas Expense Memo Account (subaccounts for (1) outreach and (2) marketing	GHG Customer Outreach and Education Memo Account	Greenhouse Gas Allowance Revenue Customer Outreach Costs Memorandum Account	2013 Customer Outreach memo account
Administrative Expenses	GHG Administrative Costs Memo Account	Greenhouse Gas Expense Memo Account (subaccount for (3) administrative costs)	GHG Administrative Costs Memo Account	Greenhouse Gas Allowance Revenue Administrative Costs Memorandum Account	2013 Administrative Costs memo account

7.2. Reconciliation of GHG Costs

The reconciled GHG costs will be used to adjust the cost-based volumetric returns to small business and residential customers. Because the Climate Credit

[49] *Id.*

is the balance after all other customer returns are made, the adjustments to the volumetric returns will in turn impact the Climate Credit.

Initially, it was necessary to establish a GHG costs sub-balancing account so that costs could be deferred until the revenue return mechanism was finalized. Cost deferment ended once the revenue return mechanism was finalized in D.13-12-041. At that time, the utilities were directed to amortize the deferred amount in the sub-balancing account and include it in rates.

The five utilities must also track GHG costs separately for reference purposes. Template D-2 provides a means for utilities to track this information without requiring special treatment in the balancing account. The utilities do not need to continue to maintain a separate sub-balancing account.

7.3. Reconciliation of Administrative and Customer Outreach Expenses

Once approved, the utility sets aside the amount of the Forecast Administrative and Customer Outreach Expenses. These expenses are then tracked in the applicable memorandum accounts until the next reconciliation.

Recorded administrative and customer outreach costs are subject to reasonableness review as part of the reconciliation portion of GHG FR&R proceedings. Thus, utilities should provide a detailed breakdown of administrative and outreach expenses, and an accompanying narrative to explain the benefit of each of these activities. Pursuant to D.12-12-033, any excess remaining in one of these memo accounts should be rolled over to the subsequent year.

7.4. Reconciliation of GHG Allowance Revenues

PG&E and SCE propose to begin reconciling GHG Allowance Revenue at the end of the filing year using the Fourth Quarter Update. As one forecast year draws to a close, the forecast for the next year is adjusted using the expected balance remaining in the GHG Allowance Revenue Balancing Account at the end of the year, including recorded amounts through the third quarter and updated forecasts for the fourth quarter. This amount, and the supporting testimony and workbooks will be part of the Fourth Quarter Update and thus subject to review before implementation.

Put another way, any amount overcollected or undercollected in the GHG Revenue Balancing Account is added to or subtracted from the total GHG revenue return for the next forecast year. Because it relies on the Fourth Quarter Update, this balance will be based on actual auction revenues, administration and customer outreach costs, GHG revenues returned to customers through the end of the third quarter, and on forecasts for the fourth quarter.

SDG&E, in contrast, proposes to reconcile the forecast year against recorded costs only after recorded amounts for the entire year are available. In other words, the 2014 forecast would not be reconciled with the 2014 recorded amounts until 2016 (based on a GHG FR&R application filed in 2015).

There are merits to both approaches. By reconciling at the end of the filing year with data available through the third quarter, the revenue return for the next year is more accurate. By reconciling only once, as part of the next year's filing, there is less risk of double counting. No party objected to either approach. However, we believe that the approach proposed by PG&E and SCE will result in the most fair and efficient return of revenues to customers. Therefore, we direct all five utilities to follow the approach recommended by PG&E and SCE.

Having all utilities reconcile the GHG revenues at the same time will make comparison and evaluation of the GHG cap-and-trade compliance programs more efficient.[50]

We expect that certain amounts tracked in the GHG ratemaking accounts will continue to be adjusted for more than one year. For example, the recorded amount spent on Clean Energy Projects may not be known for several years after the forecast. Thus the reconciliation process for all utilities should be done on a rolling annual basis using Attachment D.

7.5. GHG Revenue and Reconciliation Application Format

In Phase 1 of this proceeding, Energy Division Staff developed a Supplemental Information Form designed to obtain necessary information from all five utilities in a consistent format. All five utilities completed the Supplemental Information Form. The utilities were also ordered to file additional information, including spreadsheets, explaining the forecast costs, expenses and revenues.

For Phase 2 of this proceeding, we asked the utilities to provide an updated form that would be appropriate for future GHG FR&R applications. The utilities did not do so.[51]

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[50] ORA recommends that "revised forecasts of GHG costs and revenues should be part of the GHG cost and revenue reconciliations in the GHG Application (and update) and that this should be uniform across all utilities." (Opening Brief at 2.)

[51] At 21 of the Joint Proposal says a redline of the Supplemental Information Form will be provided, but was not clear as to when this redline would be provided. To date, no redline has been provided. Presumably the utilities mean to file a redline version with their application to show any changes to the form. Although it is sensible for the utilities to note any changes from the form, the application should be based on the attached forms. If utilities need to make changes to the forms, they should be redlined or conspicuously noted.

Energy Division staff created updated templates for future filings which are included in Attachment C and D to this decision.

7.6. Accounting Procedures

7.6.1. Accounting Procedures, Generally

Generally, the utilities follow generally accepted accounting principles (GAAP). However, in certain instances, a different accounting structure is mandated by Commission decisions, approved tariffs, and Federal Energy Regulatory Commission (FERC) requirements such as the Uniform System of Accounts. As noted above, the utilities already have specific accounts for tracking GHG costs and revenues and procedures for treatment of those amounts on a monthly and annual basis.

In accordance with GAAP, the utilities use the accrual method of accounting.[52] Under the accrual method, liabilities are booked when incurred and revenue is booked when due. Under the cash method, amounts are booked when actually received or spent. The difference between cash and accrual methods of accounting is of particular concern in tracking costs for compliance instruments obtained in one year but held for future compliance.

Prior to this year, SCE accounted for GHG costs and revenues on a cash basis.[53] SCE has agreed to switch to the accrual method starting with 2014. We confirm that SCE should switch to the accrual method beginning with 2014. SCE has agreed to record an adjustment to its ERRA balancing account that will reflect this change going forward.[54]

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[52] As discussed below, SCE has been using the cash method.

[53] SCE Reply Brief at 2.

[54] *Id.* at 3.

In the event that at the beginning of a compliance period a utility does not have in inventory any allowances or offsets that are eligible for the current compliance period, and thus cannot use the WAC methodology discussed above, the utility should use the most recent ARB allowance auction clearing price as the basis for valuing emissions and recording costs to its balancing account. Additionally, for GHG cost accrual accounting purposes it is not relevant whether or not a utility has acquired sufficient compliance instruments to cover the utility's direct emissions in a given month; for that month the recorded direct GHG costs should reflect the direct emissions multiplied by the WAC, as explained above.

7.6.2. Allowances Held for Future Compliance

For accounting purposes, compliance instruments that are held are considered prepayments and are treated as investments and included in rate base. As required by FERC, they are tracked in an allowance inventory account. However, the utilities will also need to keep a detailed accounting of purchase, sale and surrender of compliance instruments in order to make the WAC calculation required by this decision.

7.6.3. Past Years Restatement

ORA proposed that the utilities be required to restate their books and records from the November 2012 auction to the present on an accrual basis and require the utilities to reconcile indirect GHG costs using the CAISO Proxy for GHG allowance costs. With all utilities now using the accrual method, there is no need to restate past years. SCE shall use the accrual method for 2014 and shall make a one-time adjustment for prior years. Making this adjustment through the ERRA process will be sufficiently transparent for parties to understand past compliance costs.

8. Confidentiality Protocols; Motions to File under Seal

ARB's cap-and-trade regulations prohibit disclosure of auction-related information in most circumstances.[55] ARB's goal is to prevent market collusion. The ARB Confidentiality Memo provides additional guidance on ARB's view of market-sensitive information.

The Commission is interested in ensuring that the public has access to information related to utility rates. The Commission also has its own rules to protect the confidentiality of market sensitive information.

The Confidentiality Protocols are intended to meet the goals of both agencies and will ensure that the maximum amount of information can be made publicly available and shared between parties in future GHG FR&R applications. In addition, by establishing Confidentiality Protocols now, we will simplify the process and provide certainty regarding treatment of sensitive market information in future GHG FR&R applications.

In Phase I of this proceeding, the utilities were asked to coordinate a working group to draft Confidentiality Protocols addressing the following:

- Identify what information should not be disclosed under the ARB nondisclosure regulations.
- Identify subsets of information that can be disclosed to the public, to parties that sign a non-disclosure agreement, and to parties that are market participants as described in D.06-06-066.

[55] 17 CCR § 95914(c).

- Require parties requesting confidential treatment of information to continue to follow standard Commission procedures for requesting confidential treatment (even if the information falls under the ARB nondisclosure restrictions).

The Revised Joint Utility Proposal for Phase 2 included the final Confidentiality Protocols which are attached to this decision as Attachment B. The Confidentiality Protocols are the result of the 2013 working group efforts as well as the Large Users April 2014 comments. ORA supports the proposed Confidentiality Protocols,[56] and no parties objected to them.

PG&E contends that by using internal forecasts, and not a proxy public price, to set its customer rates, the "actual rate impact of forecast GHG costs . . . will necessarily reveal PG&E's internal model's GHG costs and price assumptions."[57] PG&E states that the actual rate impact of its forecast GHG cost are maintained as confidential as consistent with the confidentiality protocols, D.06-06-066, and the revised ARB regulations.

8.1. Discussion

ARB's current cap-and-trade program regulations,[58] provide that entities registered in the cap-and-trade program, as well as their direct or indirect corporate associations and advisors, shall not release any of the following information:

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[56] ORA Phase 2 Opening Brief dated May 13, 2014, at 7.

[57] Joint Utility Phase 2 Opening Brief at 6.

[58] 17 CCR § 95914(c). The utilities stipulation to the Confidentiality Protocols are contingent upon ARB's final approval of the revisions to 17 CCR § 95914(c), which govern the disclosure of auction participation information. On June 26, 2014, the Office of Administrative Law adopted ARB's draft revisions to 17 CCR § 95914(c), which came into effect on July 1, 2014.

- Intent to participate, or not participate, at auction, auction approval status, maintenance of continued auction approval;
- Bidding strategy;
- Bid price or bid quantity information; and
- Information on the bid guarantee it provided to the financial services administration.

17 CCR Section 95914(c)(2)(d) allows a Commission-regulated utility to release auction information pursuant to rules, order, or decisions of the Commission. When complying with such a rule, order or decision, the utility must notify ARB and provide reference to the applicable order, decision, or ruling.[59]

The Confidentiality Protocols are consistent with Commission rules on confidentiality. D.06-06-066, which established guidelines and a reporting matrix for the confidential treatment of procurement-related information, ensures that market sensitive will be protected from public disclosure. Generally, D.06-06-066 provides this protection for up to three years. The ARB regulations do not set a limit on the period of time information must remain confidential. As specified in D.06-06-066, information is material, and thus market sensitive, if it "affects the market price an energy buyer pays for electricity."[60]

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[59] "When the release is by an entity regulated by an agency that has regulatory jurisdiction over privately owned utilities in the State of California of information regarding compliance instrument cost and acquisition strategy and other disclosures specifically required or authorized by the regulatory agency pursuant to any of its applicable rules, orders, or decisions." (17 CCR § 95914 (c)(2)(d).)

[60] D.06-06-066 at 42.

D.06-06-066 also established a process whereby non-market participant intervenors can obtain access to certain confidential market sensitive information provided they first enter into a confidentiality agreement.

The proposed Confidentiality Protocols attached to this decision have been revised to reflect the effective date of the revised ARB regulations on confidentiality. Item 3 in the Confidential Information Matrix has also been revised so that "[f]orecasts of bundled kWh sales in total or by rate schedule" remain confidential unless subject to disclosure in another Commission proceeding.

The Confidentiality Protocols can be used to address GHG cap-and-trade procurement information in other utility proceedings and activities within the Commission's jurisdiction. For example, the Commission decisions creating the Procurement Review Group (PRG)[61] already require that the utilities make certain procurement cost information available to the PRGs. The PRGs will need information on procurement costs associated with GHG compliance. Members of the PRG (other than the Department of Water Resources (DWR)) are not market participants, and members sign a confidentiality agreement.[62] The Confidentiality Protocols attached to this decision should be used by the PRGs (provided that DWR and any other market participant are excluded). The Confidentiality Protocols may also be applicable to other proceedings and activities within the Commission's jurisdiction.

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[61] PRGs were established in D.02-08-071 as a valuable tool to review and assess details of utilities' renewable energy procurement strategy. D.02-08-071 prohibits market participants from being PRG members and requires PRG members to sign a non-disclosure agreement.

[62] Joint Utility Proposal at A-1.

In 2013, parties filed information under seal and filed motions requesting that the information remain under seal. Those motions are: Motion to File under Seal filed by PG&E filed December 6, 2013, Motion of Liberty Utilities to File under Seal filed September 18, 2014, Motion for Leave to File Confidential Prehearing Conference Statement and Supplemental Information under Seal filed by SCE on September 18, 2014, Motion for Leave to File under Seal Unredacted Version of Supplemental Information Sheet filed by SDG&E on September 18, 2014, and Motion to File Under Seal filed by Liberty Utilities on August 1, 2013. Because the Confidentiality Protocols were still being developed, we did not rule on the motions in the Phase 1 decision. In addition, the following exhibits were filed under seal pending development of the final Confidentiality Protocols: SCE-1C, SDG&E-2C. SDG&E-3C, SDG&E-4C, SDG&E-5C, SDG&E-6C, SDG&E-10C, PG&E-1C, PG&E-2C, PG&E-4C, PG&E-5C, PAC-1C, and LU-1C.

The information referenced in the motions to file under seal and the information contained in the exhibits filed under seal constitute commercially sensitive material and include information that falls under the "ARB Confidential" and "Confidential" categories in the Confidentiality Matrix.

These motions to file under seal are hereby granted and the confidential treatment of the exhibits is affirmed on the terms set forth in the Confidentiality Matrix. Motions to file under seal in future GHG FR&R applications should include a completed Confidentiality Matrix.

9. Safety Considerations

The health and safety impacts of GHG are well known and were one of the reasons that the legislature enacted AB 32. Specifically, the Legislature found and declared that global warming caused by GHG "poses a serious threat to the economic well-being, public health, natural resources, and the environment of

California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the quality and supply of water to the state from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems."[63]

This decision implements a part of the GHG reduction program envisioned by AB 32. By doing so, this decision will improve the health and safety of California residents.

10. Categorization and Need for Hearing

These consolidated proceedings have been categorized as ratesetting. It was preliminarily determined that hearings would be necessary for Phase 2 of these consolidated proceedings. It was determined in consultation with the parties that formal evidentiary hearings were not necessary.

11. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on October 2, 2014 by Liberty Utilities and PacifiCorp (jointly), ORA, SDG&E, SCE and PG&E and reply comments were filed on October 7, 2014 by ORA.

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[63] AB 32 Findings and Declarations.

12. Assignment of Proceeding; Procedural Issues

Michael R. Peevey is the assigned Commissioner and Jeanne McKinney is the assigned ALJ in these consolidated proceedings.

Findings of Fact

1. Using a proxy price for forecast GHG prices when estimating forecast GHG costs and allowance revenues will provide transparency.
2. Evaluation of a utility's GHG cost forecasts will be more efficient if utilities include their GHG FR&R requests as a chapter or section in their ERRA or ECAC forecast applications.
3. Attachments C and D, along with explanatory testimony, provide information essential to evaluating future GHG FR&R applications or requests.
4. The GHG forecast revenue and reconciliation process has been carefully examined in this proceeding and does not need to be litigated separately from forecast ERRA or ECAC applications.
5. Filing future GHG FR&R requests annually as an additional chapter or section within their with ERRA or ECAC forecast applications will provide greater consistency in evaluating GHG costs both for the purpose of calculating the GHG revenue return and for recovery of actual GHG costs.
6. The Confidentiality Protocols promote transparency and protect market sensitive information.
7. The Confidentiality Protocols provide an adequate framework for determining what types of information should be subject to confidential treatment.
8. The Confidentiality Protocols could be applied in other Commission proceedings or activities where the utility is required to provide information upon order of the Commission.

9. <u>The information subject to the motions for file under seal described above, and the information contained in the confidential exhibits, constitutes</u> material that is entitled to confidential treatment.

10. The methodologies and procedures for forecasting GHG costs, allowance revenue, and related expenses described in this decision are reasonable.

11. The methodologies and procedures for calculating recorded and estimated recorded GHG costs, allowance revenues, and related expenses, as described in this decision are reasonable.

12. The methodology and timing for annually reconciling forecast amounts with recorded amounts using a partial forecast is reasonable.

13. The methodology and timing for reconciling forecast amounts with recorded amounts must continue until all amounts are recorded for the forecast year.

14. Using Template D-2 for GHG costs allows utilities to maintain a record of GHG costs.

15. Using a balancing account for allowance revenue allows the utilities to maintain a record of allowance revenues.

16. Forecast and recorded administrative and customer outreach expenses must be reasonable.

17. Calculating the WAC of compliance instruments each month will provide a reasonable basis for calculating direct GHG costs.

18. Approval of a Clean Energy Project is beyond the scope of a GHG FR&R application.

19. Approval of a Clean Energy Project is best addressed in a separate proceeding or other applicable forum.

20. Once a Clean Energy Project has been approved, an allowance revenue appropriation can be included in a GHG FR&R application or request.

21. Calculation of the estimated forecast of revenues available for other proceedings to appropriate for clean energy or EE projects can be completed in a GHG FR&R application prior to project approval in a specific proceeding.

22. A Clean Energy Project must be approved before GHG allowance revenues can be set aside for the project.

Conclusions of Law

1. The utilities should use Attachments C and D to provide information in future GHG FR&R applications

2. The utilities should file future GHG FR&R applications or requests annually.

3. The utilities should file future GHG FR&R requests as an additional chapter or section within their forecast ERRA or ECAC forecast applications, if applicable.

4. The Confidentiality Protocols may be used in other proceedings and activities within the Commission's jurisdiction.

5. The Confidentiality Protocols comply with Commission rules including D.06-06-066, General Order 66C and Public Utilities Code Section 583.

6. It is reasonable for the information referenced in the motions to file under seal described above, and the information contained in the confidential exhibits, to remain under seal for the amount of time required by ARB and D.06-06-066.

7. The utilities should continue to use balancing accounts to track GHG costs and revenues.

8. The utilities should begin the reconciliation process for a forecast year as part of the subsequent GHG FR&R application.

9. Rates for the next year should be adjusted to reflect any undercollection or overcollection in the GHG balancing accounts at the end of the third quarter.

10. Actual administrative and customer outreach expenses recorded in the memorandum account should be subject to reasonableness review.

11. The WAC methodology in Attachment C should be used to calculate the WAC of compliance instruments.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, PacifiCorp, an Oregon Company and Liberty Utilities (CalPeco Electric) LLC, shall use a proxy price to estimate forecast allowance revenues and greenhouse gas costs, except as otherwise specifically directed by the Commission.

2. Pacific Gas & Electric Company (PG&E) may use its Market Data System procurement model to forecast greenhouse Gas (GHG) costs in its forecast Energy Resource Recovery Account proceeding, but must also provide illustrative GHG cost and rate information using the proxy price. PG&E shall clearly state in its application whether or not the difference between model forecast and the proxy price forecast is less than or greater than five percent.

3. The Confidentiality Protocols attached as Attachment A are adopted for this proceeding and any other Commission proceeding or activity that involves cap-and-trade information and meets the law, order or decision requirement of the California Cap and Greenhouse Gas Emissions and Market-Based Compliance Mechanisms, Title 17, California Code of Regulations Section 95914(c).

4. The documents placed under seal shall remain under seal for the applicable period of time set forth in the Confidentiality Matrix and shall not be made accessible or disclosed to anyone other than the Commission and its staff except on the further order or ruling of the Commission, the assigned Commissioner, the assigned Administrative Law Judge (ALJ) or the ALJ then designated as Law and Motion Judge.

5. The calculations and methodologies in Attachment B to this decision for forecasting greenhouse gas-related costs, revenues, and expenses, and the procedures in Attachment B for reconciling those amounts in the next application are adopted, as modified by this decision.

6. The method for calculating the weighted average cost of compliance instruments is set forth in Attachment C is adopted.

7. The utilities named in Ordering Paragraph 1 shall not set aside greenhouse gas allowance revenue for clean energy or energy efficiency projects (EE) until a specific qualifying clean energy or EE project is approved by the Commission.

8. When requesting approval of a clean energy or energy efficiency (EE) project to be funded with greenhouse gas (GHG) allowance revenues, the utilities named in Ordering Paragraph 1 shall use the following procedure:

> (A) As part of the forecast revenue and reconciliation (FR&R) applications or requests, a utility should forecast the amount of allowance revenue that other proceedings can appropriate for clean energy and EE projects (the Forecast Clean Energy Amount). The existence of the Forecast Clean Energy Amount will demonstrate that funds are available for qualified projects (Clean Energy Projects) to be approved in other proceedings.
>
> (B) When seeking approval of a project, the utility should include the following in its request: (a) explain why the project qualifies under 745(c), (b) explain why the project is best funded using GHG allowance revenues instead of ordinary

recovery through rates, and (c) reference the Forecast Clean Energy Amount.

(C) If a project is subsequently approved, and the utility has authority to track recorded expenses in an appropriate balancing account, these expenses should be reflected and reconciled in the utility's next FR&R application.

(D) Funds used for Clean Energy Projects are still subject to any reasonableness reviews required as part of the project approval and the Clean Energy Project Amount must still be reconciled against the recorded allowance revenues, but the Clean Energy Project funds are otherwise unencumbered.

9. The utilities named in Ordering Paragraph 1 shall include Attachment C and Attachment D, and provide reasonable supporting testimony regarding methodologies and assumptions when filing forecast revenue and reconciliation applications or requests in the future.

10. Each utility named in Ordering Paragraph 1 shall file its greenhouse gas forecast revenue and reconciliation request as an additional chapter or section within its annual Energy Resource Recovery Accounts or Energy Cost Adjustment Clause forecast application (as applicable), but in any event not later than August 1 of each year.

11. Starting in 2015, each of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall provide a fourth quarter update no later than November 15 of each year.

12. Each utility named in Ordering Paragraph 1 shall include a breakout of rate impacts resulting from greenhouse gas (GHG) costs by rate schedule in any Advice Letter filed in connection with its incorporating GHG costs and revenues into rates.

13. For purposes of cost recovery, greenhouse gas emissions costs shall be addressed in the same manner as other procurement costs.

14. The utilities named in Ordering Paragraph 1 shall use the accrual method of accounting when tracking costs and revenues related to greenhouse gas allowances and the cap-and-trade program.

15. Southern California Edison Company shall restate its accounts for 2014 using the accrual method.

16. In the event that a utility's forecast greenhouse gas (GHG) revenue return is not adopted by December 31, the utility shall continue to return GHG allowance revenue using the prior year's forecast until such time as a new revenue return is adopted.

17. Application (A.) 13-08-002, A.13-08-003, A.13-08-005, A.13-08-007, and A.13-08-008 are closed.

This order is effective today.

Dated October 16, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

ATTACHMENT A

Confidentiality Protocols

The February 19, 2014, Assigned Commissioner's and Administrative Law Judge's Scoping Memo and Ruling (Scoping Memo) in Phase 2 of the above-referenced AB 32 greenhouse gas (GHG) implementation proceeding requires the utilities (PG&E, SCE and SDG&E) to include proposed Confidentiality Protocols relating to GHG information that may be the subject of disclosure in Commission proceedings. The Confidentiality Protocols below were developed pursuant to the earlier October 4, 2013, Scoping Memo and Ruling in this proceeding with input from all interested parties and Commission staff. Since that time, revised AB 32 regulations have been issued for consideration by the ARB, and a recent ARB staff memorandum dated February 19, 2014 has been issued and included in the record of this proceeding. ARB's regulations, including 17 California Code of Regulations Section 95914(c), governing the confidentiality of auction participation information, was amended effective July 1, 2014. The utilities recommend that the Confidentiality Protocols be reviewed and updated as necessary upon issuance of the any revised ARB regulations as well as evaluation of the ARB staff memorandum. ***Accordingly, the Confidentiality Protocols are subject to the condition precedent of approval of these protocols by the CPUC.***

The Confidentiality Protocols address the following:

- Identify what information should not be disclosed.
- Identify subsets of information requested to be disclosed in CPUC proceedings that can be disclosed to the public, to parties that sign a non-disclosure agreement (NDA), and to parties that are market participants as described in D.06-06-066, if any.
- Require parties requesting confidential treatment of information to continue to follow standard Commission procedures for requesting confidential treatment.

Subject to the aforementioned condition precedent, the following Confidentiality Protocols shall govern the dissemination of GHG information in all utility matters over which the Commission has jurisdiction:

1. Pursuant to the ARB GHG non-disclosure regulations Public Utilities Code Section 454(g) and CPUC D.06-06-066 as modified by D.08-04-023, the following current or forecast confidential GHG information will not be disclosed to the public:

a. Utility AB 32 GHG auction participation, including but not limited to:

- Qualification status (ability to participate)
- Intent to participate in an auction, auction approval status, maintenance of continued auction approval
- Participation in an auction
- Auction bidding strategy
- Bid price or bid quantity information
- Bid guarantee information

b. Utility AB 32 GHG allowance procurement or revenue return positions. Specifically:

- Utility GHG price forecasts internally derived for utility procurement planning purposes
- Utility GHG compliance instrument inventories or quantities that can be used to derive GHG compliance instrument holdings

c. Utility AB 32 GHG transactions, bilateral or under a Request for Offer,. Specifically:

- Utility counterparty information submitted pursuant to a non-disclosure agreement or solicitation protocol
- Negotiated contract terms or non-public contract terms

d. Other utility procurement-related information subject to confidentiality protection pursuant to the terms of D.06-06-066 as modified by D.08-04-023, that pertains to GHG compliance. Specifically:

i. ARB allowance or offset procurement quantity targets;

ii. CPUC-approved procurement limits for compliance exposure and financial exposure; and

iii. detailed forecasted GHG financial exposure by type (direct and indirect) or resource category, including utility forecasts of payments to tolling counterparties, qualifying facilities for GHG, and increased power market costs.

2. Pursuant to CPUC regulatory litigation discovery requirements in formal proceedings under the Public Utilities Code, confidential information under #1, above, may be disclosed to interested parties or their representatives in formal CPUC proceedings if the interested parties and their representatives (a) are not market participants under D.06-06-066; (b) are not registered entities, auction participants, voluntary associated entities, or other participants in GHG allowance or offset markets under the ARB AB 32 regulations; (c) execute appropriate non-disclosure agreements and agree to comply with these Confidentiality Protocols and an appropriate CPUC-approved Protective Order in the proceeding;[64] and (d) are not prohibited by other law or privilege from receiving or reviewing the information. Confidential information under Section 1 of these protocols may not be disclosed to market participants, which include market participants designated in D.06-06-006, covered entities, auction participants, voluntary associated entities, or other participants in the ARB-regulated Cap-and-Trade market. For clarity, since voluntary associated entities in the cap-and-trade program may be individuals, market participants should include organizations that have employees who are voluntary associated entities.

3. Information that is not confidential GHG information as described in #1, above, may be disclosed to the public unless protected from public disclosure under other laws, judicial rulings or regulations, such as privileged, proprietary or confidential information restricted from disclosure under Section 583 of the Public Utilities Code, CPUC General Order 66-C, the California Public Records Act, the California Evidence Code or other laws or rules.

4. Parties requesting confidential treatment under these Greenhouse Gas Information Confidentiality Protocols will follow standard Commission

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[64] The Office of Ratepayer Advocates is subject to specific statutory confidentiality restrictions under Public Utilities Code Section 583 and therefore does not need to execute an NDA, as long as it agrees in writing to comply with these GHG Confidentiality Protocols and any applicable Protective Order.

procedures for requesting confidential treatment, including use of standard non-disclosure agreements, and motions for protective orders as appropriate.

5. The following table applies to these confidentiality protocols.

GHG CONFIDENTIAL INFORMATION MATRIX

Nature of Information	Matters	Treatment	Data
GHG Proxy Price	All utility matters over which the CPUC has jurisdiction	Public	$/MT CO2e
GHG Compliance Instrument Expected Prices	All	ARB Confidential[65]	N/A
Forecast of GHG Emissions Intensity	All	Confidential[66]	MT/MWH
Forecast of bundled kWh sales in total or by rate schedule	All	**Confidential, unless subject to disclosure in another Commission proceeding**	kWh
Forecast of annual GHG allowance revenue using proxy price	All	Public	$
Total annual forecast GHG allowance auction revenue by rate schedule using proxy price	All	Public	$
Total forecast GHG allowance auction revenue using internal procurement forward price curves or other procurement planning prices	All	ARB Confidential	N/A
Total forecast GHG allowance auction revenue by rate schedule using internal procurement forward price curves or other internal	All	ARB Confidential	N/A

[65] "ARB Confidential" information may not be disclosed to any market participant.

[66] "Confidential" information may be disclosed to a party or its reviewing representative (if the information is market-sensitive) pursuant to a non-disclosure agreement.

Nature of Information	Matters	Treatment	Data
procurement planning prices			
Total forecast GHG costs or revenue requirements using proxy price.	All	Confidential	$
Total forecast GHG costs or revenue requirements by rate schedule using proxy price	All	Public	$
Rate impact of forecast GHG costs, excluding consideration of revenue credit, by rate schedule using proxy price	All	Public	¢/kWh
Rate impact of total forecast GHG Costs or revenue requirements using internal procurement forward price curves or other internal procurement planning prices		ARB Confidential	¢/kWh
Total annual GHG costs for preceding 5 years[67]	All	Public	$
Total annual GHG revenues for preceding 5 years[68]	All	Public	$
GHG emissions intensity of utility portfolio for preceding 5 years including direct and indirect emissions	All	Public	MT/MWH
Weighted Average Cost (WAC) of compliance instruments, and the calculation of WAC	All	ARB Confidential	$

(END OF ATTACHMENT A)

67 Reference to "total" does not mean separate totals for direct and indirect costs. Such a breakdown of the total combined direct and indirect costs is confidential.

68 Differs from SDG&E GHG Confidentiality Protocols Matrix Examples. No confidential information shall be derived due to the blending of direct and indirect emissions into a single value. Also, data are historical, rather than current forecast values.

ATTACHMENT B

Joint Stipulations from Revised Joint Utility Proposal **[Annotated with References to Decision]**

A. Proxy Price

1. Revised Joint Utility Proposal and Joint Stipulation

It is stipulated that each utility will present a forecast using a proxy price based on the forward ICE settlement price for GHG allowances with December delivery of the forecast year, consistent with the methodology used by each utility to calculate forward prices for other commodities in their respective ERRA/ECAC applications. As a result of the IOUs' different ERRA/ECAC filing dates, each utility may use different dates or range of dates to ascertain the ICE settlement price to calculate its GHG proxy price.

B. GHG Cost and Revenue Forecasts

The Scoping Memo asked the IOUs to propose general methodological guidelines for forecasting total annual GHG costs and allowance revenues.

1. Cost Forecast

a) Revised Joint Utility Proposal and Joint Stipulation

Consistent with their ERRA filings, SDG&E and SCE will calculate the forecast of direct GHG costs by multiplying the forecasted emissions for UOG, imports and tolls based on ARB reporting regulations by a GHG forecast price. The forecast of the indirect GHG costs is also calculated by multiplying a GHG forecast price by expected indirect emissions. Indirect emissions can be calculated differently since there is no right way to calculate indirect emissions. The forecasted GHG price may be a proxy price or a confidential price. If filing

GHG costs based on a confidential price forecast, the utility will also present an illustrative forecast based on a proxy price.

PacifiCorp and Liberty only have direct costs and will therefore use the straightforward methodology described in the initial Joint Utility Proposal.

Consistent with the methodology used in its ERRA filing, PG&E will multiply the forecast of direct GHG emissions from UOG resources, energy imports and tolling contracts by a confidential GHG allowance price to calculate the forecast of direct GHG costs. Indirect GHG costs attributable to market energy purchases and contracts with energy payments tied to market prices are forecast as embedded in procurement costs included in the ERRA filing and are not separately estimated in the ERRA filing. For the purpose of forecasting volumetric GHG revenue return in this proceeding, PG&E will estimate indirect GHG emissions volumes from generation resources in the ERRA forecast. PG&E then will multiply the estimated indirect GHG emissions volumes by the agreed-upon proxy GHG price to estimate indirect GHG costs for the purpose of forecasting volumetric GHG revenue return in this proceeding.

The Commission will also need to determine if utilities can seek GHG cost recovery in either the ERRA or GHG proceedings. SDG&E and SCE are requesting cost recovery in their GHG Revenue and Reconciliation Application, while PG&E is seeking cost recovery in its ERRA filing. **[*See* Section 7 of Decision.]**

2. <u>Revenue Forecast</u>

a) <u>Revised Joint Utility Proposal and Joint Stipulation</u>

It is stipulated that each utility's GHG revenue forecast will be calculated by multiplying each utility's annual allowance allocation from ARB by the GHG allowance proxy price.

C. Reconciliation

The Scoping Memo asked the utilities to propose methods and procedures for cost and revenue true-up or reconciliation.

1. Cost Reconciliation

a) Revised Joint Utility Proposal and Joint Stipulation

It is stipulated that the approach to reconciliation should be consistent with the Commission-approved Joint Implementation Plan, applying only to the adjustment of small business and residential forecasted volumetric returns. Further, actual direct GHG emissions should be calculated on an annual basis and be consistent with ARB regulations for measuring GHG emissions. Indirect GHG emissions should be calculated consistent with the GHG cost forecast methods and do not have to be consistent across utilities.

Since no consensus was reached, the Commission should choose the price it prefers for indirect GHG emissions: (1) the average ICE price over the last year; (2) the sales-weighted average price of the four ARB auction clearing prices of the last year; or (3) the average of the four quarterly published prices of the CAISO GHG price index (a variation of the average ICE price). **[See Section 5.2.2 of Decision.]**

In addition, the utilities did not reach a consensus on whether a revised forecast of current year GHG costs should be part of the GHG cost reconciliation in the GHG Application, which will be updated in the fourth quarter of the year. The Commission should decide whether such a revised forecast should be included and whether it should be uniform across the utilities. **[See Section 7.2 of Decision.]**

2. Revenue Reconciliation

a) Revised Joint Utility Proposal and Joint Stipulation

1. SDG&E

SDG&E will true up its 2013 revenue, but will not true up 2014 until 2015. **[This proposal is rejected by the Decision; see Section 8.4 of Decision.]**

2. PG&E and SCE

Because the balancing accounts automatically perform a true up, the GHG Revenue and Reconciliation Applications will incorporate an estimate of the December 31, 2014 GHGRBA, which will then be updated in the fourth quarter of the year. This update will true up for actual auction revenues, administration and customer outreach costs, and GHG revenues returned to customers through September and then forecast from October through December. PG&E will incorporate its projected end of the year GHGRBA balance in its Annual Electric True-Up process, same as ERRA. **[See Sections 7.2 and 8.4 of Decision.]**

As no consensus could be reached, the Commission will also have to determine whether a revised forecast of current year GHG revenue should be part of the GHG revenue reconciliation in the Application which will be updated in the fourth quarter of the year, and whether it should be uniformly applied to all utilities.

D. Confidentiality

The Scoping Memo asked the IOUs to address the Proposed Confidentiality Protocols developed in the fall of 2013 during Phase 1 of this consolidated proceeding.

1. Revised Joint Utility Proposal and Joint Stipulation

Because the ARB's board passed the proposed revised regulation concerning confidentiality, all stakeholders now agree to the Proposed

Confidentiality Protocols, as amended by the Large Users, with a few corrections as shown in Attachment A to this pleading. **[See Section 9 and Attachment A of Decision.]**

The proposed protocols are contingent on the ARB's approval of proposed draft revisions to the 17 California Code of Regulations Section 95914(c), which governs the disclosure of auction participation information.[69] The ARB's board approved the draft revisions to the regulation on April 27, 2014, but the

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[69] The draft revised ARB regulation --17 Cal. Code Reg. § 95914 -- which was approved by the ARB board on April 27, 2014, provides, in pertinent part:

(c) Non-disclosure of Bidding Information Among Auction Participants.

(1) Except as provided in section 95914(c)(2), all entities registered into the Cap-and-Trade program pursuant to section 95830, their direct and indirect corporate associations, or consultants and advisors as identified in section 95923shall not release any of the following information regarding auction participation or reserve sale participation, as applicable:

(A) Intent to participate, or not participate, at auction, auction approval status, maintenance of continued auction approval; qualification status;

(B) Bid price or bid quantity information; and

(C) Information on the bid guarantee it provided to the financial services administrator.

(2) Auction participation information listed in section 95914(c)(1) may be released under the following conditions:

(A) When the release is to other members of a direct corporate association not subject to auction participation restriction or cancellation pursuant to section 95914(b),

(B) When the release is to a Cap-and-Trade Consultant or Advisor who has been disclosed to the Executive Officer pursuant to section 95914(c)(3).248

(C) When the release is made by a publicly-owned utility only as required by public accountability rules, statute, or rules governing participation in generation projects operated by a Joint Powers Authority or other publicly-owned utilities.

(D) When the release is by an entity regulated by an agency that has regulatory jurisdiction over privately owned utilities in the State of California of information regarding compliance instrument cost and acquisition strategy and other disclosures specifically required or authorized by the regulatory agency pursuant to any of its applicable rules, orders, or decisions. In the event of a disclosure pursuant to this section, the entity regulated by the agency must provide to the Executive Officer within 10 business days, the statutory or regulatory reference or the general order, decision, or ruling to ARB that requires the disclosure of the specific information related to bidding strategy.

regulation will not be effective until it has undergone additional approvals. The utilities stipulation to the protocols is thus contingent on final approval. **[The ARB regulations were approved effective July 1, 2014.]**

The regulation generally provides that a regulated entity may release auction participation information, including, but not limited to, compliance instrument cost and acquisition strategy, if the disclosure is required or authorized by the regulatory agency pursuant to any of its applicable rules, orders or decisions. Each time a utility makes a disclosure pursuant to a Commission rule, order or decision, it must notify the ARB's Executive Officer within 10 days of the statutory or regulatory reference or the general order, decision, or ruling that requires the disclosure. Because the regulation creates compliance and administrative burdens for the utilities, it is important that the decision in this matter clearly state that these protocols govern the release of such information and other GHG-related information in all utility matters over which the Commission has jurisdiction, including PRG meetings.[70] In addition, in the case of regular and predictable disclosures, such as to the utilities' PRGs, the Commission should authorize the utilities to make a single notification to the ARB of the dates of such meetings and that disclosures will be made in that venue.

With specific regard to the Large Users' revisions, utilities agree that auction information, as defined by the ARB's cap-and-trade regulations, should not be shared with market participants or their viewing representative. Such a

[70] For this reason, the "proceeding" column in the Large User's GHG Information Matrix can either be eliminated or specify that the rule applies to all utility matters over which the Commission has jurisdiction.

rule will not adversely impact the utilities' PRG meetings because Decision (D.) 02-08-071, which created the PRG, prohibits market participants from being PRG members. The only exception to that rule is the California Department of Water Resources (DWR). DWR has already informally agreed to recuse itself from GHG discussions during PRG meetings. **[*See* Section 9.1 of Decision.]**

In addition, the utilities propose a change to the matrix regarding the disclosure of "internal procurement forward price curves or other internal procurement planning prices" to demonstrate rate impact. Although the Large User's matrix is not utility-specific in this regard, the utilities assume that this aspect of the matrix refers to PG&E's uses of its confidential and proprietary MDS model to forecast prices, consistent with the model used internally and accepted for its ERRA forecast costs, and consistent with its ERRA and procurement planning practices.

Because PG&E proposes to set customer rates based on its internal forecast, rather than a proxy public price, the actual rate impact of forecast GHG costs using PG&E's internal procurement forward price curves will necessarily reveal PG&E's internal model's GHG cost and price assumptions. PG&E therefore proposes that the actual rate impact of its forecast GHG costs be maintained as confidential consistent with the confidentiality protocols proposed by the utilities in this proceeding and adopted by the Commission for protection of similar market sensitive procurement information in D.06-06-066. Other information will be handled as specified in the protocols. **[Attachment A of Decision specifies that "Forecast of bundled kWh sales in total or by rate schedule" shall be "Confidential, unless subject to disclosure in another Commission proceeding."]**

E. Clean Energy Set Aside

The Scoping Memo asked the IOUs to propose a procedure for utilities to seek approval of EE or clean energy program set asides. The Scoping Memo stated that the proposal should reflect the Commission's guidance in D.12-12-033. (Step 1. Seek and receive approval in relevant proceedings where EE or clean energy programs are being comprehensively reviewed; Step 2. Use approval to modify GHG revenue balancing account tariff sheets, as necessary, to allow approved funding amounts to be disbursed and recovered; Step 3. Include approved funding amounts in the next, and future, GHG Revenue Reconciliation Applications.)

1. Revised Joint Utility Proposal and Joint Stipulation

The IOUs are not in agreement regarding whether GHG revenues should be permitted to be set-aside in this proceeding or in the proceedings in which the merits of the activities funded by the set-aside are considered. The IOUs defer to the Commission to decide this issue consistent with the guidance in D.12-12-033. **[*See* Section 6 of Decision.]**

a) SDG&E

As set forth in its 2014 GHG Forecast and Reconciliation Application, SDG&E sought approval to set aside 14% of their expected GHG auction revenues to be used to fund potential incremental EE or clean energy programs in 2015. SDG&E proposes to transfer the set aside funds from the GHG revenue balancing account to the relevant projects' accounts upon Commission approval of the EE or clean energy program in the relevant proceeding. If the set aside funds are not transferred to approved programs or projects, they will be returned to customers in the following year's GHG reconciliation process. **[This proposal is rejected by the Decision. See Section 6 of Decision.]**

b) SCE, PG&E, Liberty and PacifiCorp

The other utilities state that no set aside is required and access to GHG revenues for purposes of EE and clean energy investments should be determined by the Commission in the respective EE and clean energy investment proceedings. Access to the GHG revenues will be on a first-come first-served basis for up to 15% of expected GHG revenues in the year the program or project is approved (or the following year) and will continue in the future to the end of the program or project's approved funding or 2020, whichever is earlier.

F. Information in GHG Applications

The Scoping Memo asked the IOUs to discuss the proposed worksheet form for reporting information in future GHG Revenue and Reconciliation Applications.

1. Revised Joint Utility Proposal and Joint Stipulation

The utilities agreed to provide a redline of proposed revisions of the Supplemental Information Sheet with any necessary additional line items in their respective GHG Revenue and Reconciliation Applications. **[See Section 8.5 of Decision.]**

G. GHG Accounting Procedures for Ratesetting Purposes

The Scoping Memo asked the IOUs to propose accounting procedures and rules for reporting GHG costs, allowance revenues and compliance instruments inventory. The Scoping Memo instructed the IOUs to indicate if the procedure is already being evaluated or has already been adopted in another proceeding, such as ERRA.

1. <u>Revised Joint Utility Proposal and Joint Stipulation</u>

The utilities agree with ORA that requested cost recovery of direct GHG costs going forward will be based on GHG compliance costs in the year the GHG emission obligation was incurred, with interest for cash outlays to meet GHG procurement compliance costs. The emission expense and interest expense will be recorded to ERRA. **[See Section 8.6 of Decision.]**

(END OF ATTACHMENT B)

ATTACHMENT C

Calculation of Weighted Average Cost of Compliance Instruments

A utility's recorded direct costs include two variables: emissions and costs of compliance instruments. Recorded year direct greenhouse gas (GHG) costs represent the actual costs for utility owned generation, imports, tolls and other contracts for which the utility has responsibility for Cap-and-Trade costs.

Each month, a utility records its GHG costs to its respective balancing account. These costs are calculated as the weighted average cost (WAC) of compliance instruments held in inventory at the end of a month multiplied by the quantity of emissions generated in that month for which the utility has a physical compliance obligation. For financially settled tolling agreements that a utility records as a direct cost, these direct GHG costs should be based on actual contract settlement, not on the WAC. The recorded direct costs for the year are the sum of the monthly GHG expense entries for the year.

Under California's Cap-and-Trade Program, a covered entity must surrender one compliance instrument (an allowance or an offset) for each metric ton of GHG emissions. Allowances are designated with a vintage year. An entity may bank allowances from previous vintage years, but not borrow from future vintage years, to meet a compliance obligation. For example, if a utility holds a vintage year 2013 allowance in its inventory, it can surrender the allowance to meet its 2013 obligation, or bank the allowance to surrender in future years.

There are no restrictions on which vintage year of offsets a utility can use to meet a compliance obligation.[71]

When a utility purchases or otherwise receives compliance instruments, it records:

- Transaction Date;
- Transaction Type (purchase, sale, etc.);
- Vintage (if applicable);
- Quantity of compliance instruments for transaction;
- Cost per compliance instrument for transaction;
- Total Cost of compliance instruments for this transaction calculated as the quantity multiplied by the cost; and
- Inventory Balance in dollars;
- Total Quantity of compliance instruments in inventory; and
- WAC of all compliance instruments to date.

When a utility sells, transfers, surrenders, or otherwise removes compliance instruments from its inventory, it records:

- Transaction Date;
- Transaction Type (purchase, sale, etc.);
- Vintage (if applicable);
- Quantity of compliance instruments for transaction;
- Sales price for transaction;

[71] ARB. Regulatory Guidance Document, Chapter 3. April 2013. http://www.arb.ca.gov/cc/capandtrade/guidance/20130419%20Guidance%20Document%20Ch%203%20posting.pdf.

- Total Cost calculated as quantity of compliance instruments for transaction multiplied by the current WAC;
  - Inventory Balance in dollars;
  - Total Quantity of compliance instruments in inventory; and
- WAC of all eligible compliance instruments to date.

When a utility calculates the WAC of compliance instruments in inventory, it should consider all compliance instruments in its inventory that are valid for the current compliance period. Specifically, the calculation shall include all ARB Offsets, and allowances with a vintage year equal to or prior to the recorded year. For example, in recording 2014 costs, a utility shall calculate its WAC based on its inventory of all ARB Offsets and allowances with vintage years 2013 and 2014.

When a utility purchases compliance instruments, it holds these environmental assets in inventory at the purchase price. When a utility procures additional compliance instruments, its inventory increases and its WAC might change. At any period of time, the WAC is calculated as the total cost of all compliance instruments held in inventory, divided by the total quantity of compliance instruments.

For purposes of the WAC calculation, when compliance instruments are sold, transferred, or surrendered, they are taken out of inventory at the WAC; these transactions do not change the WAC of the remaining compliance instruments held in inventory. If the compliance instruments are sold at a higher (lower) price than the WAC, the utility will record a gain (loss) on the sale. For WAC calculation purposes, allowances remain on the balance sheets as inventory (current or noncurrent) until surrendered to ARB. When allowances are surrendered to ARB, the balance sheet will be reduced by the number of allowances surrendered to ARB.

When the WAC is calculated at the end of the month, a utility will calculate recorded direct costs for the month as follows:

$$Direct\ GHG\ Costs_{month} = WAC\ \times Direct\ Emissions\ Quantity_{month}$$

Where:

"WAC" is the weighted average cost of all compliance instruments held in inventory that are eligible for that cap-and-trade compliance period.

"Direct Emissions Quantity" is the direct emissions for the entire month calculated in accordance with ARB standards, regardless of whether compliance instruments have been surrendered for these emissions. The emissions quantity is updated on at least a quarterly basis based on best available information. Emissions from financially settled tolling agreements should not be included in Direct Emissions Quantity for purposes of this calculation.

For example, when recording 2014 costs a utility shall calculate its WAC based on its inventory of all ARB Offsets and allowances with vintage years 2013 and 2014. Any allowances with vintage year 2015 will not be calculated in the WAC used for recording 2014 costs since the second compliance year begins in 2015. When recording 2015 costs, a utility shall calculate its WAC based on its inventory of all offsets and allowances with vintage years 2015, 2016 and 2017, plus any 2013 or 2014 allowances or offsets not used to meet its obligation in the first compliance period.

When a utility files its GHG Forecast Revenue and Reconciliation Application, it shall use Template C to show its WAC calculations. Each utility will use Template C to develop a calculation worksheet for each applicable compliance period. The application should also show a calculation of direct costs based on the WAC formula above. This calculation of recorded direct costs should match the emissions expenses in the utility's balancing accounts. GHG emissions from financially settled tolling agreements should NOT be included in this calculation.

If the Total Quantity in Inventory at the end of a month is equal to zero, the utility shall use the most recent ARB allowance auction clearing price instead of the WAC to calculate that month's emissions cost. The utility will record this number in place of the "End of Month WAC" to calculate that month's costs.

Template C-1: Reporting Template to Calculate Weighted Average Cost of Compliance Instruments

For tolling agreements with financial settlements, the following alternative calculation may be used:

Direct Cost = Settlement Price x Emissions Quantity

Where:

"Settlement Price" is the unit price at which the utility will financially compensate its tolling counterparty for GHG (usually the ARB Auction Clearing Price); and

"Emissions Quantity" is the emissions obligation for the entire month calculated in accordance with the tolling agreement.

The WAC inventory table and the resulting WAC calculation are confidential.

(END OF ATTACHMENT C)

ATTACHMENT D

GHG Revenue and Reconciliation Application Form

Each utility should complete the five templates provided in Attachment D when submitting its GHG Revenue and Reconciliation Application or request. The utility should complete the templates for the forecast year (denoted as "Year t" in the templates) and any years for which it is recording or reconciling costs and revenues.

Clarifying notes follow each template to provide guidance for completing the template.

Gray shading in the template indicates confidential information. As described in the notes that accompany each template, a utility may mark additional data as confidential, based on its set of circumstances.

Template D-1: Annual Allowance Revenue Receipts and Customer Returns*

Line	Description	Year t-1 Forecast	Year t-1 Recorded	Year t Forecast	Year t Recorded
1	**Proxy GHG Price ($/MT)**	-	N/A	-	N/A
2	**Allocated Allowances (MT)**	-	-	-	-
3	**Revenues ($)**				
4	Prior Balance	-	-	-	-
5	Allowance Revenue	-	-	-	-
6	Interest	-	-	-	-
7	Franchise Fees and Uncollectibles	-	-	-	-
8	**Subtotal Revenues**	-	-	-	-
9	**Expenses ($)**				
10	Outreach and Administrative Expenses (from Template D3)	-	-	-	-
11	Franchise Fees and Uncollectibles	-	-	-	-
12	Interest	-	-	-	-
13	**Subtotal Expenses**	-	-	-	-
14	**Allowance Revenue Approved for Clean Energy or Energy Efficiency Programs ($)**	-	-	-	-
15	**Net GHG Revenues ($) (Line 8 + Line 13 + Line 14)**	-	-	-	-
16	**GHG Revenues to be Distributed in Future Years ($)**	-	-	-	-
17	**Net GHG Revenues Available for Customers in Forecast Year ($) (Line 15 + Line 16)**	-	-	-	-
18	**GHG Revenue Returned to Eligible Customers ($)**				
19	EITE Customer Return	-	-	-	-
20	Small Business Volumetric Return	-	-	-	-
21	Residential Volumetric Return	-	-	-	-
22	**Subtotal EITE + Volumetric Returns**	-	-	-	-
23	**Number of Households Eligible for the California Climate Credit**	-	-	-	-
24	**Per-Household Semi-Annual Climate Credit ($) (0.5 x (Line 17 + 22) ÷ Line 23)**	-	-	-	-
25	**Revenue Distributed for the Climate Credit ($) (2 x Line 23 x Line 24)**	$ -	$ -	$ -	$ -
26	**Revenue Balance ($)**	N/A	-	N/A	-

***Template D-1 Notes**

Line 1: Proxy GHG Price

- The forward ICE settlement price of GHG allowances of the forecast year's vintage with December delivery of the forecast year, with a quote date consistent with natural gas and power price forward curves used in the ERRA/ECAC forecast.
- Proxy GHG Price is applicable to the forecast column only.
- Proxy GHG Price was not used prior to 2015.

Line 2: Allocated Allowances

- Number of allowances the California Air Resources Board allocates to each utility on behalf of its customers.

Line 3: Revenues

- Revenue from selling 100% of allocated allowances.
- If a utility records revenues received as negative values in this template, it should record expenses and revenues returned as positive values.

Line 4: Prior Balance

- Forecasted or recorded end-of-year balance in each utility's respective GHG revenue balancing account.
- Not applicable to 2013, as there was no balance prior to 2013.

Line 5: Allowance Revenue

- Forecast Allowance Revenue equals the Proxy GHG Price multiplied by the number of Allocated Allowances to the utility in a given year.
- Recorded Allowance Revenue is the total value of allowances consigned and sold at auction for a given year.

Line 6: Interest

- Recorded Interest is the interest booked to the revenue balancing account.

Line 7: Franchise Fees and Uncollectibles

- Calculated by multiplying the utility's GRC-authorized FF&U factor by the allowance revenue (including any interest).

Lines 10-12: Expenses

- Recorded Expenses reflect actual expenses recorded by filing date plus additional estimated year-end recorded expenses.

Line 10: Outreach and Administrative Expenses

- Utilities enter the total from Template D3 on this line, net of any balance in the outreach expense memorandum account or administrative expense balancing account. Note any previous year's balance applied here.

Line 11: Franchise Fees and Uncollectibles

- If a utility calculates expense-related FF&Us separately from Revenue FF&Us above, utility will enter that number here.
- Calculated by multiplying the utility's GRC-authorized FF&U factor by the outreach and administrative expenses.

Line 12: Interest

- If applicable.

Line 14: Allowance Revenue Approved for Clean Energy or EE Programs

- Amount of revenue, if any, that the Commission has authorized in other proceedings to fund clean energy or EE programs.

Line 15: Net GHG Revenues Available for Customers

- Revenue net of Expenses and Allowance Revenue for Clean Energy or EE.

Line 16: GHG Revenues to be Distributed in Future Years

- Of GHG Revenues collected in 2013, 50% is to be returned to customers in 2014 and 50% in 2015. These revenues are held in the utility's balancing account until they are distributed. When reporting recorded 2013 and 2014 revenues, and for the 2015 forecast year, the utility will indicate the amount of collected GHG revenues that will remain in the balancing account to be distributed in future years. This line can be omitted beginning in the 2016 forecast year after all revenue from 2013 and 2014 has been amortized in rates.

Lines 19-21: GHG Revenue Returned to Eligible Customers

- Recorded revenue returned to eligible customers should reflect recorded revenue returned to customers as of the filing date as well as estimated year-end recorded revenue returned to customers.

Line 19: EITE Customer Return

- As the revenue allocation formula and distribution methodologies for emissions intensive and trade exposed (EITE) customers has not been finalized as of the mailing of this decision, the forecast is based on total sales to expected bundled and unbundled EITE-eligible customers multiplied by the GHG cost in rates for these customers.
- Once EITE customers have begun receiving an EITE return, the forecast return is based on the recorded prior-year revenue returned to EITE customers.

Line 20: Small Business Volumetric Return

- Forecast based on expected bundled and unbundled sales to small business customers multiplied by forecast volumetric GHG costs in rates and appropriate assistance factors.

Line 21: Residential Volumetric Return

- Forecast based on expected bundled and unbundled sales to residential customers multiplied by the volumetric GHG costs in rates.

Line 24: Per-Household Semi-Annual Climate Credit

- The recorded amount exactly equals the forecast for that year, as the forecast is used to calculate the amount of the Climate Credit.

Line 25: Revenue Distributed for the Climate Credit

- Forecast Revenue Distributed for the Climate Credit is the net allowance revenue available for customers less the subtotal of EITE and volumetric revenue returns.
- Recorded Revenue Distributed for the Climate Credit is the actual amount returned to all households.

Line 26: Revenue Balance

- The recorded Revenue Balance will be the known or estimated amount recorded in the utility's respective balancing account on December 31 of that year.
- Only applicable to the recorded column.
- The Revenue Balance at the end of one year then becomes the Prior Balance (line 4) of the next year.

Template D-2: Annual GHG Emissions and Associated Costs**

		Year t-1		Year t	
Line	Description	Forecast	Recorded	Forecast	Recorded
1	**Direct GHG Emissions (MTCO2e)**				
2	Utility Owned Generation (UOG)	-	-	-	-
3	Tolling Agreements	-	-	-	-
4	Energy Imports (Specified)	-	-	-	-
5	Energy imports (Unspecified)	-	-	-	-
6	Qualifying Facility (QF) Contracts	-	-	-	-
7	Contracts with Financial Settlement	-	-	-	-
8	**Subtotal**	-	-	-	-
9	**Indirect GHG Emissions (MTCO2e)**				
10	CAISO Market Purchases	-	-	-	-
11	Contract Purchases	-	-	-	-
12	**Subtotal**	-	-	-	-
13	**Total Emissions (MTCO2e)**	-	-	-	-
14	**Proxy GHG Price ($/MT)**	-	-	-	-
15	**GHG Costs ($)**				
16	Direct GHG Costs	-	-	-	-
17	Direct GHG Costs - Financial Settlement	-	-	-	-
18	Indirect GHG Costs	-	-	-	-
19	Previous Year's Forecast Reconciliation (Line 21)	N/A	N/A	-	-
20	**Total Costs ($)**	-	-	-	-
21	**Forecast Variance ($)**	N/A	-	N/A	-

Gray shading indicates confidential information. As described in the notes below, based on a utility's particular circumstances additional cost data may be confidential.

Gray shading indicates confidential information. As described in the notes below, based on a utility's particular circumstances additional cost data may be confidential.

**Template D-2 Notes

Line 1: Direct GHG Emissions
- Direct GHG Emissions are confidential.
- Utilities will provide data for all categories of Direct GHG Emissions that are applicable to their operations.
- If a utility is a multi-jurisdictional retail provider (MJRP) that reports MJRP emissions, the utility shall add a line under Direct GHG Emissions to include MJRP emissions. This value is confidential.

Line 2: Utility Owned Generation
- Emissions based on forecasted or actual plant output, the facility-specific heat rate assumption, and ARB-specified emissions factors for fuels.
- This value is confidential.

Line 3: Tolling Agreements
- Emissions based on forecasted or actual plant output purchased by utility, the contract-specific heat rate assumption, and ARB-specified emissions factors for fuels.
- This value is confidential.

Line 4: Energy Imports (Specified)
- Emissions based on forecasted or actual plant output purchased by utility and the facility-specific emissions factor.
- This value is confidential.

Line 5: Energy Imports (Unspecified)
- Emissions based on forecasted or actual plant output purchased by utility, the ARB emissions factor for unspecified imports, the ARB transmission loss correction factor, and any applicable RPS adjustment.
- This value is confidential.

Line 6: Qualifying Facility Contracts
- Physically settled emissions based on forecasted or actual plant output purchased by utility and the contract-specific settlement terms.

- This value is confidential.

Line 7: Contract with Financial Settlement

- Emissions from utility contracts in which the utility is responsible for providing financial settlement specifically for GHG costs. At its discretion, the utility may choose instead to record financially settled emissions as a new row under Indirect GHG Emissions.
- This value is confidential.

Line 8: Subtotal

- This value is confidential.

Line 9: Indirect GHG Emissions

- Because Total Emissions are public except when a utility only reports direct emissions, Indirect GHG Emissions must be confidential to avoid revealing Direct GHG Emissions.
- Utilities will provide data for all categories of Indirect GHG Emissions that are applicable to their operations. Utilities that have no Indirect Emissions do not need to complete this section.

Line 10: CAISO Market Purchases

- Emissions based on net market energy purchases and either ARB's emission factor for generic system power or a market heat rate-implied emission factor.
- This value is confidential.

Line 11: Contract Purchases

- Emissions based on forecasted or actual plant output purchased by the utility and contract-specific settlement terms.
- This value is confidential.

Line 12: Subtotal

- This value is confidential.

Line 13: Total Emissions

- Total of direct and indirect emissions.

- This value is confidential if a utility has only direct emissions, because it would reveal their direct compliance exposure.

Line 14: Proxy GHG Price

- The forecast Proxy GHG Price is used to forecast Direct GHG Costs and Indirect GHG Costs.
- The forecast Proxy GHG Price is the forward ICE settlement price with December delivery of the forecast year, with a quote date consistent with natural gas and power price forward curves used in the ERRA/ECAC forecast. This value is public. PG&E separately calculates a confidential GHG price which it uses to forecast procurement costs for ratemaking purposes in the ERRA forecast proceeding.
- PG&E must use a confidential internal GHG allowance price forecast for the Proxy GHG Price if this is consistent with its ERRA methodology.
- The recorded Proxy GHG Price is used to calculate the recorded Indirect GHG Costs. The value is the average of the daily published prices of the California System Operator (CAISO) GHG Allowance Price Index for that year. This value is public.

Line 16: Direct GHG Costs

- The Direct GHG Costs included the cost of Direct GHG Emissions in Lines 2 through 7 only.
- Forecast direct costs are the Forecasted Proxy Price (or confidential price for PG&E) multiplied by forecasted direct emissions.
- Recorded direct costs are the sum of each month's WAC of compliance instrument inventory multiplied by that month's actual direct emissions, as shown in Template C.
- These values are confidential to avoid revealing a utility's Direct GHG Emissions.

Line 17: Direct GHG Costs - Financial Settlement

- The Direct GHG Costs for Contracts with Financial Settlement include the cost of Direct GHG Emissions in Line 7.
- Forecast direct costs with financial settlement are the Forecast Proxy Price (or confidential price for PG&E) multiplied by forecast direct emissions.

- Recorded direct costs are the sum of each month's cost of financially settling the GHG cost component of contracts.
- These values are confidential to avoid revealing a utility's Direct GHG Emissions.

Line 18: Indirect GHG Costs ($)
- Forecast Indirect GHG Costs are the Forecast Proxy Price multiplied by forecast subtotal of Indirect GHG Emissions.
- Recorded Indirect GHG Costs equal the subtotal of Indirect GHG Emissions multiplied by annual average of CAISO's daily GHG Allowance Price Index computed by averaging the published daily price for the recorded year and dividing by the number of days in that year.

Line 19: Previous Year's Forecast Reconciliation
- Equals Forecast Variance (line 20) from the year the utility is reconciling.
- This value is confidential if the previous year's Forecast Variance is confidential.

Line 20: Total Costs
- Forecast of total costs are confidential if utility uses a confidential price for its Forecast Proxy Price (line 14). In that case, utility's GHG application must include an illustrative public GHG cost using the public forecast proxy price.
- This value is also confidential if a utility has only direct costs.

Line 21: Forecast Variance
- Total recorded costs minus total forecasted costs for the year.
- If the forecast of Total Costs (line20) is confidential, the forecast variance is also confidential.

	-	-	-	-
	-	-	-	-
	-	-	-	-
	-	-	-	-
	-	-	-	-
	-	-	-	-
Total Outreach and Administrative Expenses (Line 7 + Line 8)	-	-	-	-

***Template D-3 Notes

Lines 1-3: Utility Outreach Expenses

- Utilities provide detail on the categories of outreach activities they forecast and actually work on.
- Examples of outreach categories include customer call center outreach, internal marketing efforts, printed materials, postage, and contracts with external marketing consultants.
- Utilities will insert line items to account for applicable outreach sub-categories, including the examples listed here and any other relevant sub-categories.

Lines 4-6: Utility Administrative Expenses

- Utilities provide detail on the type of administrative activities they forecast and actually complete.
- Examples of administrative work include general program management, IT enhancements, billing system enhancements, IT program management and oversight, and customer call center training.
- Utilities will insert line items to account for applicable administrative sub-categories, including the examples listed here and any other relevant sub-categories.

Line 8: Additional (Non-Utility) Statewide Outreach

- Utility’s portion of expenses for a third-party to support statewide outreach.

Template D-4: Costs and Revenues by Rate Schedule and Emissions Intensity****

******Template D-4 Notes**

Column A: Rate Schedule

- Utilities add rows to the template to populate Column A with all applicable rate schedules.

Columns B-E: Bundled Customers

- Data in these columns are for bundled sales/customers.

Column B: Forecast kWh Sales

- Provide by rate schedule and in total.
- Confidential, unless subject to disclosure in another Commission proceeding.

Column C: Forecast GHG Revenue Requirement

- Provide by rate schedule and in total for the forecast year.
- This value is confidential if the utility uses a confidential internal price to forecast GHG costs.

Column D: Rate Impact of Forecast GHG Revenue Requirement

- For each line, this equals Column C divided by Column B.
- The rate impact does not include the impact of the revenue credit.
- If a utility's Forecast GHG Revenue Requirement is confidential, this value is also confidential. If this value is confidential, the utility shall insert an additional column to show an illustrative, public rate impact by rate schedule using a proxy GHG price.

Column E: Forecast GHG Revenue

- Provide by rate schedule and in total for the forecast year using the proxy price.
- The sum of Column E and Column I should equal that year's Net GHG Revenues Available for Customers in Forecast Year (Line 17 of Template D-1).

Columns F-I: Unbundled Customers
If a utility serves unbundled customers, it will complete columns F through I in the same manner it completed these fields for bundled customers in columns B through E.

Template D-5: History of Revenue, Costs, and Emissions Intensity***

Line		Year t-5	Year t-4	Year t-3	Year t-2	Year t-1	Year t
1	Total GHG Costs ($)						
2	Total GHG Revenues ($)						
3	Emissions Intensity ($MTCO_2e/MWh$)						

*******Template D-5 Notes**

Lines 1-3

- Complete each line for the forecast year, and up to five preceding years.
- Fill in the headers with the actual years and indicate which years are forecasts, rather than actuals.

Line 2: Total GHG Revenues

- Equals the Net GHG Revenues Available for Customers from Template D-1. Utilities should report recorded values for prior years and forecast values when recorded values are not available.

Line 3: Emissions Intensity

- Emissions Intensity for the forecast year is confidential.

(END OF ATTACHMENT D)