STATE OF CALIFORNIA GAVIN NEWSOM

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN RULEMAKING 22-12-011:

This is the proposed decision of Commissioner Darcie L. Houck.
Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's October 8, 2026 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:smt
Attachment

Decision **PROPOSED DECISION OF COMMISSIONER HOUCK**
(Mailed 9/4/2026)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Address Biomethane Procurement Cost Allocation.	Rulemaking 22-12-011

DECISION ALLOCATING BIOMETHANE ABOVE-MARKET COSTS

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DECISION ALLOCATING BIOMETHANE ABOVE-MARKET COSTS

Summary

This decision finds that all investor-owned gas utility customers should pay a share of the above-market costs of the Renewable Gas Standard (RGS) program.

This proceeding was opened to address two fundamental questions: which customers should share in RGS above-market costs, and how the cost should be allocated among them. We find that the RGS above-market costs, which represent the cost of meeting policy goals to reduce pollutant emissions from bio-waste, should be allocated on an equal cents per therm[1] basis to all core customers. To extend cost allocation to all core customers, this decision directs the inclusion of the allocated costs within core transportation rates.

The allocation of costs is not extended to non-core customers at this time, pending further assessment of whether an exemption (either in whole or in part) should apply to non-core customers. An additional process on this matter is needed to identify whether and how to implement cost allocation in a way that avoids emissions leakage and encourages industry to stay in California. This decision orders the joint gas utilities to lead a workshop process and subsequently file an application that considers recommendations coming out of the work as to whether and how these issues should be addressed.

This decision also adopts and defines several aspects of RGS program above-market costs.

This proceeding is closed.

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[1] A therm is 100,000 British thermal units (Btu). A Btu is the amount of energy needed to raise the temperature of one pound of water by 1 degree Fahrenheit. https://www.eia.gov/energyexplained/units-and-calculators/british-thermal-units.php

1. Background

In 2022, the California Public Utilities Commission (Commission) adopted a biomethane procurement program, the Renewable Gas Standard (RGS) program, in D.22-02-025 for the purpose of reducing harmful emissions from landfills, dairies, and other sources. In D.22-02-025, the Commission also stated that it would open a separate proceeding to consider distributing the above-market costs of the RGS program to all customers, including unbundled and non-core customers. Thus, the instant proceeding considers the appropriate allocation of costs and related matters.

1.1. Procedural background

Senate Bill (SB) 1440 (Hueso, 2018) required the Commission to consider adopting biomethane procurement targets or goals for each investor-owned utility (IOU) providing gas service in California. On November 21, 2019, the Commission initiated Phase 4 of Rulemaking (R.) 13-02-008 to implement SB 1440.

In R.13-02-008, Decision (D.) 22-02-025 implemented Senate Bill (SB) 1440 by setting biomethane[2] procurement targets to reduce short-lived climate pollutant emissions. D.22-02-025 established the RGS program, a means of procurement, adopted provisions to achieve co-benefits, and established timetables for each IOU providing gas service in California to achieve specified procurement targets.

R.13-02-008 also considered the question of whether the Commission should consider distributing above-market biomethane procurement costs to

[2] Biomethane is methane from biological feedstocks and also known as renewable natural gas or RNG. Once fully processed, biomethane is chemically identical to fossil methane.

non-core customers,[3] but ultimately the Commission decided to open a separate proceeding focused on that question: Ordering Paragraph (OP) 53 of D.22-02-025 states, "The Commission will open a ratesetting proceeding to consider distributing above-market biomethane procurement costs to non-core customers."[4]

On December 15, 2022, the Commission issued an Order Instituting Rulemaking (OIR) opening the instant proceeding to address RGS above-market cost allocation. Leadership Counsel for Justice and Accountability (LCJA) filed opening comments on the OIR on February 17, 2023. On February 21, 2023, the following parties filed opening comments on the OIR:

- Agricultural Energy Consumers Association (AECA);
- California League of Food Producers (CLFP) and California Manufacturers & Technology Association (CMTA), jointly;
- Coalition for Renewable Natural Gas;
- Shell Energy North America (Shell) and Alliance for Retail Energy Markets (AREM), jointly;
- Small Business Utility Advocates (SBUA);
- The Utility Reform Network (TURN);
- The Public Advocates Office at the California Public Utilities Commission (Cal Advocates);
- San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and Southwest Gas Corporation (Southwest Gas), jointly (collectively, Gas IOUs); and

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[3] Most natural gas utility customers in California are residential and small commercial customers, referred to as "core" customers. Larger volume gas customers, such as electric generators and industrial customers, are called "non-core" customers.

[4] D.22-02-025, at page 71, OP 53.

- Southern California Generation Coalition (SCGC).

On March 13, 2023, AECA, the Gas IOUs, Indicated Shippers, TURN, CMTA and CLFP, and SCGC filed reply comments on the OIR.

The assigned Administrative Law Judge (ALJ) Bemesderfer held a prehearing conference on April 24, 2023. On December 12, 2023, the Bioenergy Association of California (BAC) filed a motion for party status and ALJ Bemesderfer granted BAC's motion on December 13, 2023.

Also in 2023, Assembly Bill (AB) 678 (Alvarez, 2023) amended Public Utilities Code (Pub. Util. Code) Section 651 to address natural gas core transport agents (CTAs).

The assigned Commissioner issued a Scoping Memo and Ruling (Scoping Memo) on March 20, 2024. On April 15, 2024, SoCalGas and SDG&E (the Sempra Utilities) requested modifications to the proceeding schedule and ALJ Fox granted this request.

The following parties served Direct Testimony on May 6, 2024:

- Indicated Shippers, AECA, CMTA, and CLFP, jointly (Joint Parties);
- PG&E;
- SCGC;
- The Sempra Utilities; and
- Southwest Gas.

A May 29, 2024 ALJ Ruling required the Gas IOUs to serve procurement cost data. On September 12, 2024, the Gas IOUs filed this data, which was subsequently admitted into the evidentiary record.

The Joint Parties, PG&E, SCGC; the Sempra Utilities; Southwest Gas; and TURN served Rebuttal Testimony on June 5, 2024.

Parties submitted a Joint Case Management Statement on August 7, 2024, which among other things included a summary of issues not in dispute, issues that remained in dispute, a matrix of party positions on issues, and a joint exhibit list.

The following parties filed opening briefs on September 26, 2024: Cal Advocates; Joint Parties; LCJA; PG&E; SCGC; the Sempra Utilities; Southwest Gas; and TURN. SBUA late filed an opening brief and a confidential opening brief on September 27, 2024. The ALJ granted SBUA's motions to late file these documents on November 22, 2024. Subsequently, SBUA filed a motion on December 23, 2024 for the Docket Office to accept the late submission of these late filed documents; that motion was granted on January 24, 2025.

The following parties filed reply briefs on October 10, 2024: AECA, CMTA, CLFP, and Indicated Shippers jointly; LCJA; PG&E; SBUA; SCGC; the Sempra Utilities; and TURN.

In May 2025, ALJ Fox required filing of additional information related to CTAs via an ALJ Ruling (CTA Ruling). The Gas IOUs filed responses containing CTA information on June 12, 2025. Shell/AREM, Indicated Shippers, and the Gas IOUs filed supplemental briefs on June 23, 2025 and reply briefs on July 7, 2025 responding to the CTA Ruling.

On July 21, 2025, ALJ Maria Sotero was assigned to the proceeding.

On February 5, 2026, the ALJ issued a supplemental ruling (2026 Supplemental Ruling) authorizing parties to respond to 17 specific questions related to environmental attributes, cost allocation principles and methodologies, and other issues. On March 9, 2026, PG&E, Southwest Gas, the Sempra Utilities, NRG Business Marketing, LLC, LCJA, SBUA, and Indicated Shippers filed and served opening comments. On March 17, 2026, the Sempra Utilities, LCJA, PG&E and Indicated Shippers filed and served reply comments.

On May 19, 2026, the ALJ issued another supplemental ruling (Second Supplemental Ruling) authorizing party comments responding to two issues: updates considering D.26-04-044, which had been adopted the prior month, and a potential pathway for exemptions for certain non-core customers. On June 3, 2026, Indicated Shippers, Southwest Gas, SCGC, PG&E, and the Sempra Utilities filed and served opening comments. On June 12, 2026 PG&E filed and served replies, and on June 15, 2026, the Sempra Utilities, SCGC, and LCJA filed and served replies.

This matter was submitted on June 12, 2026 upon filing of second supplemental reply comments.

1.2. Relevant Program Changes in D.26-04-044

In April 2026, the Commission adopted D.26-04-044 making changes to the RGS program. One of the changes made in that decision was the creation of a cost containment mechanism (CCM) applicable to RGS contracts. Under the CCM, the rate impacts of RGS contracts will be evaluated when they are submitted to the Commission for approval, and contracts whose costs exceed the CCM will not be approved.

Under the construct in the decision, the CCM of each contract will be calculated using net above-market costs. D.26-04-044 directs the IOUs to file a Tier 1 Advice Letter with a standardized reporting template to measure rate impacts across the Utilities' customer classes for the purposes of the CCM.[5]

[5] D.26-04-044 Ordering Paragraph 3.

D.22-02-025 required the utilities to retain the Renewable Thermal Certificates (RTCs) accompanying biomethane. R.13-02-008 considered the question of whether the utilities should be allowed to sell RTCs or leave ownership with the biomethane producer (unbundling the RTC and methane). D.26-04-044 concluded that doing so would pose the risk of double-counting and other program complications but authorized a process for further consideration of this possibility.[6]

2. Jurisdiction

Commission jurisdiction over natural gas corporations, public health, public safety, and the Renewables Portfolio Standard (RPS) program is provided by, but not limited to, Health and Safety (H&S) Code Sections 25420, 25421; Pub. Util. Code Sections 216, 222, 228, 399.11 through 399.31, 451, 761 784, 950 through 969; and General Orders (GOs) 58-A, 58-B, and 112-E.

The Commission's jurisdiction specifically addressing biomethane is provided by Pub. Util. Code Section 651. Pub. Util. Code Section 985 provides the Commission authority to establish minimum standards applicable to CTAs.

The Commission's broad jurisdiction is established in Pub. Util. Code Section 701.

Public utilities have a fundamental duty to ensure:

> All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable. (Pub. Util. Code Section 451.)

3. Issues Before the Commission

The issues to be determined are:

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[6] D.26-04-044 at 46.

1. Quantification of above-market costs: What costs, in addition to the commodity cost of biomethane, transportation, and distribution should be included in the biomethane procurement costs?
2. Avoided transmission costs:
    a. How should the Commission account for avoided costs of upstream interstate and intrastate transmission?
    b. Should those avoided costs be deducted from otherwise allocable above-market biomethane procurement costs?
3. Environmental benefits: Can environmental benefits be quantified? If so, what method should be used to quantify environmental benefits?
4. Cost allocation methodology:
    a. What cost allocation methodology should be used? For example, should costs be allocated on an equal volumetric basis, such as equal cents per therm (ECPT), or using fixed and proportional volumetric rates?
    b. Should some portion of above-market costs be allocated to third-party marketers who buy and sell for non-core customers?
    c. Should any customer groups receive special considerations or exemptions from cost allocation, including California Alternate Rates for Energy (CARE) customers, Family Electric Rate Assistance Program (FERA) customers, or customers in disadvantaged communities? If so, what adjustments should the Commission make to the cost allocation methodology for these customer groups?
5. Environmental benefit allocation:
    a. How should the associated environmental benefits of biomethane substitution for fossil gas be shared among customer classes?

   b. How might such sharing affect the obligations of non-core customers under California's Cap-and-Invest program?

6. Should the Commission establish a new nonbypassable charge for biomethane procurement?
7. If the Commission establishes a new nonbypassable charge for biomethane procurement, by what regulatory authority could this program be created?
8. If the Commission establishes a new nonbypassable charge for biomethane procurement, should investor-owned utilities (IOUs) maintain exclusive ownership of all environmental attributes from contracted biomethane sources as directed in D.22-02-025?

This decision does not address Issues 6, 7 and 8 because it does not allocate costs to all customer classes.

4. Total Costs and Benefits

4.1. Definition of Cost Terms Used in this Decision

The primary focus of this proceeding is determining how to allocate the above-market costs of the RGS program. Issue 1 in scope regards quantifying above-market costs. As a prerequisite to this issue, we first address how market costs are defined.

Parties use a range of terms (and define them differently) when referring to market costs, above-market costs, and total costs. Therefore, for clarity we first define how this decision uses these three terms.

4.1.1. Total Renewable Gas Standard Program Costs

There are several different but essentially equivalent ways to define "total RGS program costs." Total RGS program costs are made up of natural gas market costs and net RGS program above-market costs. Total RGS program costs can also be defined as the sum of the commodity costs and all other authorized net costs associated with the program. Total RGS program costs can also simply be defined as the total incurred cost of implementing the RGS program. This decision uses the term in all of these different contexts.

We take this opportunity to emphasize that this proceeding does not consider RGS program cost *authorization*. No costs are authorized for collection from ratepayers in this decision. Costs that are allocated pursuant to this decision have been or must be authorized for recovery from ratepayers elsewhere. (Generally, authorization of specific RGS program costs has occurred in R.13-02-008, while transportation, storage, and other cost recovery authorization for gas utility services occurs in General Rate Cases or other proceedings.)

We do address how utilities will verify that certain authorized costs are associated with the RGS program in Section 9, Implementation Process.

4.1.2. Above-market costs

This proceeding considers how to allocate RGS above-market costs only. Market costs remain allocated to bundled core customers. This section addresses the definition of RGS above-market costs. To do so, we first clarify the terms "commodity cost" and "contract cost."

The Scoping Memo uses the term "procurement costs" to refer to costs in scope of this proceeding; in that way, it equates "procurement costs" with RGS above-market costs. Throughout the record, parties use the term "commodity cost" and other similar variants to refer to the cost of the biomethane itself and to differentiate it from other costs associated with the RGS program. For the purposes of clarity in this decision, we use the term "RGS commodity cost" to refer specifically to the cost of the actual biomethane and differentiate it from associated costs such as transportation or storage.[7] We also clarify that, because the RGS program uses solicitations and bilateral contracts (in which biomethane producers agree to supply biomethane to utilities), and these contracts do not include other costs incurred by the utility associated with the program, the term "contract cost" is understood to refer to the commodity cost.

The RGS program already has a working definition of RGS above-market costs. In D.22-02-025, the Commission ordered the utilities to establish balancing accounts for the program, with two subaccounts to record (1) above-market commodity biomethane costs and (2) program administrative costs necessary to support both general biomethane procurement and specific pilot projects.[8] The utilities filed Advice Letters implementing this order that contain their definitions of above-market costs, the wording of which varies slightly, but the meaning of which is essentially the same: the utilities calculate a basic market cost of fossil gas and RGS costs above that are the above-market costs.

SoCalGas' definition is: "The above-market biomethane commodity cost is defined as the difference in the cost of biomethane purchases (including the cost of any renewable attributes or credits that are bundled with the purchased biomethane supply) and the monthly weighted average cost of traditional natural gas purchases."[9]

Southwest Gas' definition is: "The above-market Biomethane cost is defined as the difference in the monthly weighted average cost of Biomethane

[7] For example, to compare biomethane commodity cost to fossil gas commodity cost.

[8] D.22-02-025 at 28, OP 54. According to this OP, the recovery of the balancing account costs shall be done through the utilities' respective Annual Gas True-Up filings.

[9] SoCalGas Advice Letter 5965-G at 2, available at https://tariffsprd.socalgas.com/view/filing/?utilId=SCG&bookId=GAS&flngKey=4314&flngId=5965&flngStatusCd=Approved.

purchases (including the cost of any renewable attributes or credits that are bundled with the purchased Biomethane supply) and the monthly weighted average cost of traditional natural gas purchases."[10]

PG&E's definition is: "Above-market RNG commodity expenses equal the RNG commodity price less the traditional natural gas commodity price."[11]

Notably, the definitions of above-market costs in the utilities' balancing accounts do not include or account for some types of costs that are being discussed for allocation in this proceeding, such as the costs to transport and store biomethane. This decision's definition of RGS above-market costs is: all authorized costs associated with the RGS program above the market cost of fossil gas. "Authorized" in this definition means "authorized for collection from ratepayers." (We note that customers also pay costs beyond just the commodity cost of fossil gas, for example transportation and storage costs.)

In sum, we reiterate that total RGS costs equal commodity costs and all other authorized costs associated with the program; from this total, market costs will be subtracted and the remaining above-market costs will be allocated.

Put another way, RGS above-market costs represent the incremental cost (above the market cost of fossil gas) of using biomethane procurement to reduce emissions from biological feedstock sources. Other factors, such as reduction in Cap-and-Invest compliance costs and any avoided costs, reduce the above-market costs. Our discussion of quantifying and allocating above-market costs bears all this in mind.

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[10] Southwest Gas Advice Letter 1210-G, Sheet 45-20, available at https://www.swgas.com/rate/1409213331106/SWG_AL-1210_Establish-BPACBA-per-D.22-02-025.pdf.

[11] PG&E Advice Letter 4597-G, Gas Preliminary Statement Part D, Sheet 2, available at https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4597-G.pdf

4.1.3. Market costs

Throughout the record, parties equate "market costs" with the cost that the utility would otherwise incur for fossil gas on the market. As discussed in the prior subsection, each of the gas utilities filed advice letters to record their above-market costs; in doing so, they each articulated how they would define market costs. Therefore, the program already has in place a working definition of market costs: the cost of traditional (fossil) gas. Below, this decision addresses how to specifically define and calculate the fossil gas benchmark to determine market cost.

4.2. Quantifying Above-Market Costs

The question before us here is: "What costs, in addition to the commodity cost of biomethane, transportation, and distribution, should be included in biomethane procurement costs?"[12] We first define the specific market-price benchmark to be used before addressing which types of costs make up total RGS above-market program costs.

4.2.1. Benchmark for Market Cost

Because the market cost represents the dividing line beyond which RGS costs are allocated, we first need to address how the market cost will be calculated for the purposes of cost allocation. As discussed above, the gas utilities each have a basic working definition of market costs for the RGS program since that definition is reflected in their calculation for above-market costs. SoCalGas and Southwest Gas' RGS program tariffs define market cost as the "monthly weighted average cost of [fossil] gas purchases."[13] PG&E uses different wording for the same concept, defining market cost as the "[fossil] gas

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[12] Scoping Memo Issue 1.

[13] SoCalGas Advice Letter 5965-G at 2; Southwest Gas Advice Letter 1210-G, Sheet 45-20.

commodity price."[14] But for the utilities to fairly and consistently allocate above-market costs, they need a consistent, precise methodology for calculating and updating a market cost benchmark.

4.2.1.1. Party Positions

The OIR stated an assumption that "all biomethane procurement costs over the market costs of fossil gas" are above-market costs. There is no opposition to this concept.[15] SoCalGas, SCG/SDG&E, PG&E, SCGC, and the Joint Parties support it.

Multiple parties suggest we use market data from the utilities' Citygates to benchmark market cost.[16] Citygates are gas commodity trading hubs inside California. In general, a gas "Citygate" is any point at which the backbone pipeline transmission system connects to the distribution system. A Citygate is not one specific, physical location; it represents a virtual trading point on the natural gas system. There is agreement among multiple parties that California's Citygate prices reflect fossil gas market costs.[17]

SCGC provides detailed recommendations regarding the market cost benchmark, agreeing with the utilities that fossil gas cost at the Citygate is the appropriate reference point. SCGC explains that because the Citygate is the point in a utility's system where multiple suppliers deliver gas, Citygate sales reflect

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[14] PG&E Advice Letter 4597-G.

[15] OIR at 6.

[16] Exhibit SCG/SDGE-1 at 2, Exhibit SCGC-01 at 4, Exhibit PG&E at 1-2.

[17] PG&E 2026 Supplemental Comments at 12-13, Sempra Utilities 2026 Supplemental Comments at 7, Southwest Gas 2026 Supplemental Comments at 7, SCGC 2026 Supplemental Comments at 4, Cal Advocates OIR Comments at 6, Exhibit SCGC-01 at 4.

trading and competition; furthermore, SCGC notes that Citygate prices appropriately do not reflect downstream costs like distribution delivery.[18]

However, not all parties agree with using *average* Citygate prices to set the benchmark for market cost. The Joint Parties "argue for using the highest price of fossil gas on the market instead of average price," asserting that "[e]valuating above-market costs by comparing the actual, delivered costs of biomethane procurement with the highest delivered costs for [fossil] gas procurement… will incentivize the gas IOUs to reduce their reliance on costlier supplies of [fossil] gas."[19]

SBUA provides contradictory recommendations on this issue. In briefs, SBUA supports using the highest market cost, saying that biomethane should displace the most expensive fossil gas.[20] But in its response to the 2026 Supplemental Ruling, SBUA says that it would be reasonable to use the "weighted average periodic (monthly, etc.) market price."[21]

PG&E disagrees with SBUA, reiterating that "to simplify the approach and avoid making unnecessary assumptions" a weighted average should not be used and that the Citygate benchmark data is easy to find in independent industry publications.[22] PG&E recommends the market cost be updated monthly, at the end of the month, to calculate a monthly average of average daily Citygate prices using "independent third-party sources."[23] SoCalGas recommends sourcing

[18] Exhibit SCGC-01 at 4.

[19] Exhibit Joint-01 at 10.

[20] SBUA Reply Brief at 10.

[21] SBUA 2026 Supplemental Comments at 4.

[22] PG&E 2026 Supplemental Comments at 13.

[23] PG&E 2026 Supplemental Comments at 13.

Citygate prices from "established, independent, transparent market publishers," listing as options the "Natural Gas Citygate indices from Argus, Natural Gas Intelligence; Platts, Inside FERC, or Intercontinental Exchange; California-specific Citygate prices, e.g., SoCal Citygate; and government or regulatory agencies that track wholesale natural gas price indices (CPUC and parties already refer to "Citygate" generically, which in practice is sourced from these market reporters)."[24] SoCalGas suggests updating the market cost benchmark monthly for the purpose of quantifying above-market costs.

Finally, in response to the 2026 Supplemental Ruling, Indicated Shippers (the only one of the Joint Parties to respond to the ruling) deviates from the Joint Parties' recommendation to use the highest market price for the market cost benchmark and states that the utilities:

> should leverage existing sources of gas market benchmarking techniques such as those included in PG&E's Commodity Procurement Incentive Mechanism (CPIM) and SoCalGas' Gas Cost Incentive Mechanism (GCIM)…. For example, one benchmark model could be the PG&E CPIM standard benchmark, which is comprised of five components for the applicable CPIM period: (1) Fixed transportation costs; (2) variable costs, which include natural gas commodity costs; (3) storage costs; (4) hedging costs; and (5) U.S. Customs and Border Protection's Merchandising Processing Fee.

4.2.1.2. Discussion

We do not adopt the Joint Parties' recommendation to use the highest market cost for fossil gas. They argue that this would incentivize the utilities to avoid the costliest fossil gas, but do not provide their logic or explain *why* this would be the case. We surmise their logic to be that using the highest cost as the

[24] SoCalGas and SDG&E 2026 Supplemental Comments at 7.

benchmark would increase utilities' incentive to keep that dividing line lower so that as much cost as possible would be allocated. The Joint Parties could be correct that such an approach would push utilities to avoid the costliest fossil gas. But under that same logic, using the *average* market cost as the benchmark would therefore incentivize utilities to reduce their *average* market cost, which could be more beneficial to ratepayers than reducing the highest single price paid during the month.

Similarly, we also disagree with SBUA that setting the benchmark at the highest price would result in biomethane displacing the highest-priced fossil gas. There is no support for the assertion that biomethane will necessarily displace only the most expensive fossil gas simply because we set the benchmark at that point; many other factors will influence timing and quantities of biomethane production and delivery.

A given quantity of biomethane in a pipeline displaces that amount of fossil gas. Because the market cost of fossil gas represents the cost that the utility would have otherwise incurred for gas, it is reasonable to use the cost of fossil gas as the market cost benchmark for the purposes of allocating total RGS above-market costs.

With respect to exact calculations, it is reasonable to use the most straightforward approach reflecting recent, average Citygate prices to arrive at the market cost benchmark of fossil gas. Using undefined weighted averages or unspecified market data would not support transparency, nor do we have the record to support the details of any such approach.

The utilities will calculate the monthly market cost benchmark for the purposes of RGS program above-market cost allocation using average daily Citygate prices from that month. The utilities will use independent third-party sources for the data for their respective Citygates. The utilities will detail their approach in the Cost Allocation Advice Letters required by this decision, specifying the exact sources and monthly timing they will use. Once approved, the utilities will use that methodology to calculate a market cost benchmark for each month in which they procure biomethane, multiplying the market cost benchmark amount by the biomethane quantity procured in that month to arrive at the RGS Cost Allocation market cost benchmark: the cost the utility would have paid to procure that amount of fossil gas on the market in that month. All authorized, associated RGS program costs incurred in that month that exceed the RGS Cost Allocation market cost benchmark are RGS above-market costs and will be allocated pursuant to this decision.

4.2.2. Types of Costs to be Allocated

Consideration of the quantification of above-market costs encompasses how we will define what costs are allocable. It also reflects a basic assumption that the costs reflected in procurement contracts (the commodity cost) and the cost of delivering the gas will be included. No party disputed this basic assumption that allocable costs include costs other than the commodity cost (aside from those who dispute aspects of allocating costs at all). Parties provided input regarding what other types of costs should also be included and allocated.

4.2.2.1. Party Positions

Party positions on this issue varied widely, but at a high level, their input leads us to several overall conclusions. First, the record shows agreement that managing and distributing RGS biomethane will have associated costs, which should be included. While parties may define the details of some types of costs differently, most parties agree on the concept of including various costs beyond the biomethane commodity cost in our allocation. A review of the record also makes apparent that parties use different terms and definitions to refer to the same type of costs. And finally, the record shows that there is currently no consensus about how to quantify or estimate many of these costs.

PG&E stated that above-market costs should include all costs necessary to represent the total delivered cost of biomethane procurement,[25] including contracted costs, additional pipeline capacity costs, and other costs[26] associated with biomethane procurement.[27] For example, PG&E states that if it "procures gas from a biomethane facility that is connected to the SoCalGas system, PG&E may be required to procure additional pipeline capacity to transport the gas to PG&E customers. This additional pipeline capacity cost should be included in the biomethane procurement cost."[28]

SoCalGas and SDG&E asserted that above-market costs equal: biomethane contracted (commodity) costs, less energy revenue from gas used by core customers, program administration costs, incremental intrastate gas transmission costs, revenue/credits or cost/charges related to managing procurement, and/or monetization of associated environmental benefits.[29] In addition, SoCalGas and SDG&E argue for including costs pursuant to SoCalGas Rule 30 within above-

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[25] Exhibit PG&E-01 at 1-1 to 1-2; Exhibit PG&E-02 at 1-3.

[26] PG&E states that these "other costs" include 1) storage, 2) park and loan services, 3) fees associated with tracking and reporting of environmental attributes from biomethane procurement, 4) other taxes or fees associated with these items, and 5) any costs to transport and deliver biomethane.

[27] Exhibit PG&E-01 at 1-1 to 1-2.

[28] Exhibit PG&E-01 at 1-1 to 1-2.

[29] Exhibit SCG/SDGE-1 at RMS-MWF-1.

market costs (SoCalGas' Rule 30 regards standards for pipeline injection of biomethane).[30]

Southwest Gas stated that above-market costs include biomethane commodity costs, variable transmission costs, incremental capital infrastructure costs, and operations and maintenance (O&M) costs.[31]

SCGC stated that above-market costs should be based on the specific terms of the gas supply contract. The contract would establish terms of the delivery and cost responsibility.[32] Costs would reflect the location of the biomethane supply and which contractual party – supplier or purchaser – bears the cost of delivery of the supply to the utility system.[33]

The Joint Parties oppose the allocation of above-market costs to non-core customers, but say that if these costs are allocated, the above-market costs should include only the commodity price, transportation, and delivery with appropriate deductions for avoided costs and quantifiable environmental benefits.[34]

In line with that recommendation, Indicated Shippers argued for using the following methodology to calculate above-market cost:

> Above-Market Biomethane Procurement Costs = Biomethane [commodity] price + transportation and delivery costs not already included in the [commodity] price – avoided costs such as upstream interstate and intrastate transmission charges – quantifiable environmental benefits – the highest delivered cost of [fossil] gas in the IOU's system.

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[30] Exhibit SCG/SDGE-1 at RMS-MWF-1.

[31] Exhibit SWG-1 at 2.

[32] Exhibit SCGC-01 at 3:11-18.

[33] Joint Case Management Statement, Appendix B; Exhibit SCGC-01 at 3.

[34] Exhibit Joint-01 at 5. *See* also Joint-01.

Cal Advocates believes there are no currently quantifiable costs to include, other than the commodity cost, and the costs of transportation and distribution.[35]

TURN does not have a detailed position here, simply acknowledging that "there may be reasonable disputes about the precise amounts" of costs and benefits to be allocated.[36] Instead, TURN urges a focus on the forest, not the trees: "TURN submits that the circumstances here warrant the Commission prioritizing establishment and implementation of the correct cost allocation and recovery mechanism, even if it means applying those outcomes to less than perfectly precise calculations of the underlying costs or benefits."[37]

SBUA has a similarly high-level view, stating "SBUA has not attempted to determine or quantify the above-market costs…[h]owever, all above-market costs that are borne by utilities should be included," and "the reasonableness of any specific future costs is outside the scope of this proceeding."[38]

4.2.2.2. Discussion

As the prior section reflects, a wide range of associated costs were raised for consideration in the allocable total RGS program costs. These included:

Biomethane commodity costs: the cost of the biomethane itself.

Costs to transport and deliver biomethane, such as:

- Additional pipeline capacity costs: the cost to utilities to reserve capacity on in-state backbone transportation system to transport biomethane within the state.
- Storage costs: The cost to utilities to store gas in gas storage facilities.

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[35] Exhibit CA-01 at 1.

[36] TURN Opening Brief at 5.

[37] TURN Opening Brief at 5.

[38] SBUA Opening Brief at 3-4.

- Park and loan services costs: These are the costs to customers for services from the utility to either hold gas in short-term storage (park) or deliver an advance on gas (loan).
- Tracking fees: The costs associated with tracking and reporting of environmental attributes from biomethane procurement.
- Incremental infrastructure and operations and maintenance costs.
- Other taxes or fees associated with these items.

All parties agree with including the commodity cost of biomethane, as well as any quantifiable authorized costs associated with transporting and distributing biomethane. Multiple parties, including all the utilities, identify various other costs associated with the program and support their inclusion in total program costs. No party posits that any such costs are currently quantifiable; for example, some parties agree there will be pipeline capacity costs associated with delivering biomethane,[39] but do not quantify these.

With respect to the process of tracking and allocating costs, SBUA is correct in its characterization of cost authorization: RGS program contracts will be submitted for approval by the Commission, and other authorized costs associated with the RGS program will be tracked for allocation and reviewed in the utilities' respective Annual Gas True-up advice letter filings, which is the venue directed for cost recovery in D.22-02-025.[40] Such costs will be incurred during the operation of the program and will depend on a multitude of factors, such as the location, production quantity, and production timing of biomethane

[39] Exhibit CA-01 at 1-2, Exhibit PG&E-01 at 1-1.

[40] D.22-02-025, Ordering Paragraph 54.

projects.[41] As reflected in SCGC's proposal (to define allocable costs based on the terms of the contract), total authorized associated costs will be reflected in the utility's recorded costs.[42]

There are existing authorization processes for storage, pipeline capacity, and pipeline infrastructure costs and the utilities will incur any such costs associated with implementing the RGS program subject to those processes; here, we are concerned only with identifying which associated costs should be allocated pursuant to this decision.

The utilities' cost data filings provide illustrative cost impacts, reflecting estimated biomethane commodity and transportation costs.[43] It is not possible to quantify in advance all costs associated with the RGS program (or any other program); this fact does not impair our determination that authorized above-market costs associated with the RGS program should be allocated accordingly. We find that the utilities will incur associated authorized costs other than just the commodity cost and transportation and distribution costs, so it would not be reasonable to define allocable costs that narrowly. With the exception of avoided transmission costs (discussed in the following section), the record does not address how costs associated with the RGS program -- such as storage – differ from those same costs associated with fossil gas; this also does not change our finding that such related costs should be allocated.

Based on the record, it is reasonable to define RGS above-market costs as "all authorized costs associated with the RGS program above the market cost of

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[41] Exhibit SCGC-01 at 3.

[42] Exhibit SCGC-01 at 3.

[43] Updated Procurement Cost Data filings: Exhibit PG&E-03C, Exhibit SCG/SDGE 3C, Exhibit SWG 3C.

fossil gas." Among such costs are commodity, transportation, and administrative costs. Pursuant to updates in D.26-04-044, which retained rules from D.22-02-025 requiring utilities to retain (and not sell) RTCs, this does not currently include RTC marketing costs. Above-market costs will also reflect cost savings and avoided costs such as avoided Cap-and-Invest compliance costs as well as cost savings from reduced interstate transport if these costs are quantified in the future.

We reiterate that this decision does not authorize ratepayer recovery of any costs. Costs allocated pursuant to this decision will have been or must be authorized elsewhere. Parties raised a wide range of cost types that may be associated with the program, most of which are already authorized for ratepayer collection. If the utilities encounter in the future an entirely new cost associated with implementing the RGS program, they will need to seek cost recovery authorization for that cost via a General Rate Case or other application.

This decision defines RGS above-market costs as all authorized costs associated with the RGS program above the market cost of fossil gas. Within this context, "authorized" means "authorized for collection from ratepayers." All above-market costs will be allocated because they all represent the total cost of achieving the RGS program purposes.

As noted above, the utilities currently record RGS costs in the balancing accounts authorized by D.22-02-025, and request recovery of those costs in their Annual Gas True-up advice letters. This decision requires reporting and additional detail, directing the utilities to itemize each cost associated with the RGS program, including where the cost was authorized and a detailed description of how the cost is associated with the RGS program. Further detail on this process is addressed in Section 9, Implementation Process.

This decision also directs the utilities to update their RGS program tariff definitions accordingly to reflect a definition of above-market costs consistent with the definition adopted here.

4.3. Avoided Transmission Costs of Biomethane

The issues before us in this section are, "How should the Commission account for avoided costs of upstream interstate and intrastate transmission?"[44] and, "Should those avoided costs be deducted from otherwise allocable above-market biomethane procurement costs?"[45]

4.3.1. Party Positions

These scoping issues reflect one basic concept: that producing and delivering biomethane in California avoids the transmission costs of fossil gas from outside California (and potentially within California). The Joint Parties support it, affirmatively stating that there are two types of avoided costs of in-state biomethane: the actual avoided upstream transportation costs, and the avoided social cost of that upstream transmission.[46]

Other parties rebut this. PG&E states that there are no avoided transmission costs because the utilities are still required to comply with reliability standards that require firm procurement from outside California, citing the interstate pipeline reliability standard and the 1-day-in-10 peak demand reliability standard.[47] PG&E explains that because biomethane production is not stable enough to be used towards meeting these reliability standards, the utilities will still have to pay for pipeline capacity and therefore

[44] Scoping Memo Issue 2a.

[45] Scoping Memo Issue 2b.

[46] Joint Parties Opening Brief at 6.

[47] Exhibit PG&E-01 at 1-3.

will not avoid any transmission costs.[48] Cal Advocates, SoCalGas, and SDG&E agree. Cal Advocates reiterates: "The gas utilities must reserve and contract for adequate volumes of interstate and intrastate pipeline capacity, which includes a minimum volume of firm interstate pipeline capacity and matching intrastate backbone capacity rights. There is no evidence that the procurement of biomethane will currently result in avoided costs of such upstream interstate and intrastate transmission charges."[49]

SCGC takes a different approach, asserting that avoided transmission costs are reflected in Citygate prices, and therefore once the market cost is subtracted, the above-market costs of biomethane will already reflect avoided transmission costs.[50]

In rebuttal testimony, SCGC responds to PG&E, Cal Advocates, SoCalGas, and SDG&E's arguments that biomethane will not result in avoided transmission costs. SCGC counters that it will, for two reasons: first, as demand for gas decreases reliability capacity standards will also decrease, and therefore at the same time the proportion of biomethane on the system will be increasing (compared to fossil gas) and therefore biomethane will contribute an increasing amount to reliability.[51] Second, SCGC believes that utilities will be able to address any firm reliability concerns within the biomethane contracts, for example by including terms that require biomethane producers to pay for Citygate deliveries if they fail to deliver biomethane when it is needed.[52]

[48] Exhibit PG&E-01 at 1-3.

[49] Exhibit CA-01 at 1.

[50] SCGC-01 at 5.

[51] SCGC-02 at 2.

[52] SCGC-02 at 2-3.

Particularly because biomethane could be located within the utility's service area, SCGC sees no reason to conclude that it will not reduce the need for transportation capacity to meet reliability requirements.

Regardless of their positions on whether RGS program biomethane will avoid transmission costs, parties agree that any avoided transmission costs of the RGS program cannot currently be defined in detail, differentiated from Citygate prices, or quantified in advance.

4.3.2. Discussion

The record clearly shows disagreement regarding whether the RGS program avoids transmission costs, at least in the context of the biomethane market that currently exists. But otherwise, parties are remarkably aligned.

Parties agree that, if they exist, these costs cannot be currently quantified; no party put forward any specific methodology to do so. SCGC argues that avoided transmission costs are reflected in Citygate prices but does not suggest that they can be separately quantified. No party disputes that the RGS program has the *potential* to result in these avoided costs in the future: under PG&E's logic, increased firm deliveries of biomethane in the future would avoid these costs; quantities would have to be more certain, but not necessarily large. Furthermore, no party disputes that any such avoided costs – once and when quantifiable – should be accounted for within the above-market cost calculation.

We do not adopt a definition of biomethane avoided transmission costs in this decision, or quantify these costs, since the record does not support either conclusion. There is no clear, quantifiable method available for measuring these benefits and deducting them from costs. Biomethane quantities may need to become more predictable before this can be achieved, as several parties raised. However, we do acknowledge that in concept, any avoided transmission costs should be deducted from RGS above-market costs, if any such quantifiable method emerges in the future. We may consider specific proposals or methodologies for quantifying these avoided costs in the future.

4.4. Quantifying and Allocating Environmental Benefits

Scoping Issues 3 and 5 address environmental benefits. Issue 3 asks, "Can environmental benefits be quantified? If so, what method should be used to quantify environmental benefits?"[53] Issue 5 asks, "How should the associated environmental benefits of biomethane substitution for fossil gas be shared among customer classes?"[54]

Parties addressed these questions in testimony and briefs, and the 2026 Supplemental Ruling delved deeper into the issue. Part 1 of the ruling focused specifically on Renewable Thermal Certificates (RTCs), which are digital certificates that the utilities plan to use to track and verify biomethane carbon intensity and compliance with biomethane procurement targets. The 2026 Supplemental Ruling asked whether RTCs should be used to quantify the environmental attributes of biomethane in the RGS program for the purposes of cost allocation.

Under the program established in D.22-02-025, the utilities will use RTCs for tracking and compliance, and the utilities were required to retain ownership of RTCs. In D.26-04-044 the Commission did not modify these ownership rules, but authorized a process for considering whether it is possible to do so in the future without creating double-counting issues.[55]

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[53] Scoping Memo Issue 3.

[54] Scoping Memo Issue 5a.

[55] D.26-04-044 at 46; Conclusion of Law 11.

The 2026 Supplemental Ruling asked for party input on RTC potential value, as well as whether changes to the utility ownership requirement could affect above-market costs and how to ensure ratepayers benefit from any such changes.

4.4.1. Party Positions

Party views here run the gamut. Some parties recommend precise methodologies for quantifying environmental benefits while others say approximations suffice. Some parties say environmental benefits from biomethane exist but quantifying them is impossible. Still others say the entire quantification exercise is unnecessary, either because environmental benefits do not exist, or because we do not need to quantify them to allocate RGS program above-market costs. Among parties who believe benefits exist, a point of consensus emerges: these benefits should be passed to customers in the form of reduced above-market costs.

Multiple parties, including the Joint Parties, SoCalGas and SDG&E, PG&E, SCGC, Southwest Gas, agree that environmental benefits exist and that they can and should be quantified (whether precisely or loosely, in whole or in part) and that the resulting value should then be subtracted from above-market costs.[56]

The Joint Parties argue for using a method based on figures in D.22-02-025, in which an average cost of biomethane (of $17.70 per MMBTU) subtracted from the social cost of fossil gas (of $26.60 per MMBtu) results in a quantifiable environmental benefit of $8.90 MMBtu.[57] The Joint Parties do not explain the logic behind this method other than referencing that these were the figures for

[56] Exhibit PG&E-01 at 1-4, Exhibit Joint-01 at 8, Exhibit SCG/SDG&E-1 at RMS-MWF-7.

[57] Exhibit Joint-01 at 8.

social cost and average cost used in that decision. They also state that another method would be to quantify environmental benefits by equating them with the reduced costs of Cap-and-Invest (or GHG) compliance that accompany biomethane when it replaces fossil gas.[58]

The Southern California-based utilities, along with SCGC, argue for a detailed study to quantify environmental benefits. The Sempra Utilities state that benefits can only be partly quantified, but list five different categories of RGS program environmental benefits. These categories are: avoided Cap-and-Invest compliance costs; the value of GHG reductions under SB 1440 and RGS procurement targets; the value of GHG reduction that does not meet AB 1440 criteria; the value of biomethane "market enablement and catalyzation"; and value of other components that "may emerge as clean fuel markets evolve."[59] The Sempra Utilities propose a study or working group to further refine the approach to quantifying environmental benefits, and state that "the sharing of environmental benefits will evolve alongside progress made towards state goals and addressing climate change."[60] Similarly, SCGC says that "environmental benefits constitute avoiding the incurrence of [the monetary value of social cost of methane], which could be estimated," and without recommending specifics states that "a detailed study" would be required.[61]

Showing skepticism regarding other approaches, PG&E and Southwest Gas believe that avoided Cap-and-Invest costs partly quantify RGS

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[58] Exhibit Joint-01 at 8. *Also, note:* Under California Air Resources Board (CARB) Cap-and-Invest (formerly Cap-and-Trade) regulations, emissions from biomethane carry no compliance obligation. We refer to this value as "avoided GHG compliance costs."

[59] Exhibit SCG/SDGE-1 at RMS-MWF-4.

[60] Exhibit SCG/SDGE-1 at RMS-MWS-8.

[61] Exhibit SCGC-01 at 6.

environmental benefits.[62] PG&E states that other benefits such as reduced SCLPs cannot be quantified but benefit all residents and sectors of California's economy.

The Joint Parties, the Sempra Utilities, PG&E, Southwest Gas, SCGC, Cal Advocates, and SBUA agree that any quantified environmental benefits should be allocated to customers by deducting them from above-market costs, thereby benefiting all customers in the form of reduced costs.[63]

Finally, the ratepayer advocacy groups discount the entire exercise. Cal Advocates states that "quantification of environmental benefits is not germane to the primary issue of this Rulemaking," because doing so is not required to allocate costs fairly.[64] In fact Cal Advocates believes that the best way to socialize RGS environmental benefits is simply to promptly allocate its costs to all customers.[65] (Still, Cal Advocates agrees that any eventual quantified benefits should be subtracted from above-market costs.[66]) Similarly, TURN warns us not to be distracted and delayed by attempting to quantify benefits precisely, saying such an exercise could "easily become a regulatory morass" and is not necessary to achieve fair cost allocation.[67] SBUA concurs: "a cost allocation methodology should be developed in this proceeding even though the existence nature and economic value of environmental benefits and reasonableness of procurement costs cannot be determined on the current record."[68]

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[62] Exhibit PG&E-01 at 1-4, Exhibit Southwest Gas at 4.

[63] Joint Case Management Statement Attachment B at 2.

[64] Exhibit CA-01 at 2.

[65] Exhibit CA-01 at 2, Cal Advocates Opening Brief at 3.

[66] Exhibit CA-01 at 3.

[67] TURN Opening Brief at 5-6.

[68] SBUA Opening Brief at iv.

LCJA argues that any supposed benefits of the RGS program "cannot and should not be quantified."[69] In opposition to TURN and Cal Advocates' view that cost allocation should proceed regardless, LCJA argues that such "partial quantification of supposed 'environmental benefits' will lead to an inaccurate allocation of costs."[70] Additionally, LCJA notes that any benefit quantification that does not also consider the environmental harms of the RGS program will similarly yield inaccurate results. LCJA argues we must not make any such allocation here, urging us to first – and in R.13-02-008, not here -- comprehensively assess the environmental harms and costs of biomethane along with any supposed benefits.[71]

4.4.2. Use of Renewable Thermal Certificates to Value Environmental Benefits

Renewable Thermal Certificates (RTCs) are digital certificates that can be used to track and verify biomethane carbon intensity and compliance with biomethane procurement targets. RTCs are tracked by CleanCounts[72] which also tracks the Renewable Energy Credits (RECs) that result from other kinds of renewable energy production such as wind and solar and are used for compliance in California's Renewables Portfolio Standard. D.22-02-025 ordered the utilities to require RGS program biomethane producers to track their volumetric injections of biomethane using this or another similar system,[73] and D.26-04-044 confirmed that progress towards RGS program targets would

[69] Joint Case Management Statement Attachment B at 2.

[70] LCJA Opening Brief at 3.

[71] LCJA Reply Brief at 2-3.

[72] Formerly Midwest Renewable Energy Tracking System or M-RETS.

[73] D.22-02-025 Ordering Paragraph 10.

continue to be tracked via RTCs.[74] D.22-02-025 also required the utilities to maintain exclusive ownership of the RTCs.[75]

Despite the discussion of RTCs in R.13-02-008 and the direction in D.22-02-025 that RTCs would be used to track RGS program biomethane and its carbon intensity, parties did not specifically discuss RTCs in testimony or briefs. To build the record around the issues of RTCs whether they quantify any RGS program environmental benefits, the February 4, 2026 Supplemental Ruling asked whether RTCs appropriately value these benefits; what factors affect the value of RTCs; how and whether such value can be allocated to ratepayers; and other questions.

Multiple parties support the use of RTCs for valuing RGS program environmental benefits for the purposes of cost allocation. Indicated Shippers stated its support for using RTCs as the method of quantifying environmental benefits.[76] The Sempra Utilities agree that "RTCs do capture the comprehensive value of the environmental attributes of biomethane, for the purposes of cost allocation."[77] The Sempra Utilities say RTC use is appropriate because it "avoids over-recovery, supports decarbonization goals, and protects customers from unnecessary financial burden."[78] Southwest Gas agrees, noting RTCs are "recognized by prominent voluntary greenhouse gas reporting standards, including those established by the California Air Resources Board and the

[74] D.26-04-044 at 46.

[75] D.22-02-025 Ordering Paragraph 50.

[76] Indicated Shippers 2026 Supplemental Comments at 3.

[77] Sempra Utilities 2026 Supplemental Comments at 1.

[78] Sempra Utilities 2026 Supplemental Comments at 2.

Environmental Protection Agency," and reiterating the robust workshop process subsequent to D.22-02-025 that affirmed their use for this program.[79]

PG&E appears in part to misunderstand the issue, stating that "RTCs are not appropriate for comprehensively valuing the environmental attributes of biomethane *for the purposes of cost allocation* because cost allocation should be based on above-market costs, not environmental attributes"(emphasis in original).[80] This is confusing given that, as discussed above, PG&E agrees that the value of environmental benefits should be deducted from above-market costs; the ruling asked whether the *value* of RTCs could be used for this purpose.

Further, PG&E states that RTCs are unsuitable because RTCs track both biomethane volumes and carbon intensity (CI), but projects with the same production volumes and different CIs receive the same number of RTCs.[81] PG&E says this fact undermines the usefulness of RTCs for quantifying projects' environmental benefits. This logic is unclear to us as well, since (as PG&E itself notes[82]) the value of the different RTCs can be expected to vary based on CI. Overall, PG&E continues to support using the avoided GHG compliance costs to quantify the environmental benefits of the RGS program.

LCJA argues that any use of RTCs for this purpose is inappropriate because RTC carbon accounting is flawed and therefore deducting their value from above-market costs overstates the environmental benefits of biomethane.[83]

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[79] Southwest Gas Supplemental Comments at 2.

[80] PG&E 2026 Supplemental Comments at 2.

[81] PG&E 2026 Supplemental Comments at 2.

[82] PG&E 2026 Supplemental Comments at 5.

[83] LCJA 2026 Supplemental Comments at 4.

In addition to the issue of RTCs as a way of quantifying benefits, the scope of this proceeding includes whether the utilities should "maintain exclusive ownership of all environmental attributes from contracted biomethane sources as directed in D.22-02-025."[84] To address whether allowing the sale of RTCs could benefit ratepayers by lowering above-market costs, the Supplemental Ruling sought input on RTC value and risk.

Parties' supplemental comments showed total uncertainty about the current and future value of RTCs. The utilities note the infancy and inconsistent activity of this voluntary market and the resulting inherent risk, the fact that location of projects will likely also affect RTC value, "competition from compliance and voluntary markets, supply scarcity, and shifting regulatory conditions. Pricing is also influenced by the commercial terms of an RTC transaction, particularly the RTC's eligibility to participate in regulatory frameworks or incentive programs."[85]

4.4.3. Discussion

The record supports several clear conclusions with respect to quantifying and allocating environmental benefits. As an overall matter, we agree with the Joint Parties, the Sempra Utilities, PG&E, SCGC, and Southwest Gas that RGS program environmental benefits can be at least partly quantified, and that environmental benefits should be shared with customers via a reduction of above-market costs.

TURN, SBUA and Cal Advocates urge us not to get bogged down in quantification; we agree that cost allocation should proceed even if the measures

[84] Scoping Memo Issue 8.

[85] PG&E 2026 Supplemental Comments at 5, Sempra Utilities 2026 Supplemental Comments at 2.

for quantifying and deducting environmental benefits are incomplete. There may be other benefits – and negative impacts – of the RGS program, as LCJA argues, but we do not agree that a full and extensive accounting must occur before any existing measures can be used to reduce above-market costs. It is reasonable to approve measures for benefits quantification we already have; this does not impair our ability to adjust or add to these approaches in the future as biomethane evolves and better analysis of its impacts becomes available.

Additionally, we agree with most parties that any benefits that can be quantified should be shared with customers in the form of reduced RGS above-market program costs. This is a simple, straightforward way to share these benefits, and it is the only one described in the record (other than some parties' arguments that ratepayers would be better off without RGS costs entirely, which we address elsewhere).

The record shows two main ways that the RGS program environmental benefits can be partly quantified. The first is related to avoided GHG compliance costs. The use of fossil gas by utility customers creates a compliance obligation for the utility under California's Cap-and-Invest Program, in which every metric ton of emissions must be covered by a compliance instrument and submitted to CARB.[86] The utilities must purchase compliance instruments (carbon allowances and offsets) incurring what we refer to as GHG compliance costs. Although a molecule of methane made from biogenic sources is indistinguishable from one coming from fossil sources, the emissions from the use of biomethane do not carry a compliance obligation under CARB regulations.

[86] CARB's Cap-and-Invest Program is governed by Title 17, California Code of Regulations Sections 95801-96022.

Because any RGS biomethane injected into California's pipelines would necessarily replace the equivalent volume of fossil gas, biomethane therefore avoids the GHG compliance cost that the utility would have otherwise incurred and passed to customers. This cost can be easily quantified using GHG market data, and can also be seen as representing the value of avoiding the use of fossil gas, which provides environmental benefits. It is reasonable therefore to conclude that at least part of the environmental benefits of RGS biomethane can be quantified by calculating the avoided GHG compliance cost associated with the equivalent amount of fossil gas. It is also reasonable based on the record to share the quantified avoided GHG compliance cost with customers who are paying RGS costs by subtracting that value from above-market costs before allocating them. This decision directs the utilities to deduct avoided GHG compliance costs accordingly as part of the allocation accounting process discussed in Section 9, Implementation Process.

The other quantifiable approach is to use RTCs. The following section addresses these issues.

4.4.3.1. Recent Direction in D.26-04-044

R.13-02-008 addressed issues related to RTCs and D.26-04-044 again affirmed their use for the RGS program. As an accepted methodology for tracking biomethane production and CI, we find it reasonable to conclude that RTCs capture, at least in part, environmental attributes of the RGS program.

We note that this conclusion does not currently have any direct impact on above-market costs being allocated. This is because utilities are required to retain ownership of RTCs under existing rules; utilities may not sell RTCs, nor may utilities execute contracts that allow biomethane producers to retain them. Therefore, RTCs cannot *currently* be translated into dollar values that can be subtracted from above-market costs. As previously noted, R.13-02-008 considered, and D.26-04-044 addressed, the question of whether the utilities should be allowed to sell RTCs or leave ownership with the biomethane producer (unbundling the RTC and methane). In that decision we concluded that doing so would pose the risk of double-counting and other program complications.[87] We further stated:

> Recognizing this, the Commission does not authorize unbundling at this time. Therefore, Biomethane procurement will only count towards the RGS targets if a utility purchases and retires the RTC. However, we continue to believe that there are compelling reasons to explore allowing some disaggregation of biomethane's environmental attributes. Unbundling may have the potential to reduce program costs and improve cost effectiveness for ratepayers. Providing a mechanism to monetize or otherwise value biomethane's carbon intensity can therefore improve cost effectiveness and program outcomes.[88]

D.26-04-004 authorized the utilities to file advice letters with further proposals for marketing RTCs and addressing double-counting concerns. It also permitted the utilities to purchase gas without RTCs from RGS program projects; such methane would be considered "brown gas" and would not contribute to any RGS program targets.[89] Again, these provisions are not immediately relevant to cost allocation, as there is currently no approved method for RTCs to generate financial value and therefore there is no pathway for the benefits captured by RTCs to reduce RGS above-market costs.

But the potential exists. And for that reason, and because the record here supports this conclusion, we confirm that RTCs capture some amount of the

[87] D.26-04-044 at 46.

[88] D.26-04-044 at 46.

[89] D.26-04-044 at 47.

environmental benefit of the RGS program. If in the future the utilities are authorized to monetize RTCs, any financial value of RTCs should be subtracted from the above-market costs of related RGS biomethane before its allocation to customers.

4.5. Cap-and-Invest Program Considerations

The Scoping Memo asks, in relation to the sharing of environmental benefits of the RGS program among customer classes: "How might such sharing affect the obligations of non-core customers under California's Cap-and-[Invest][90] program?"[91]

This decision does not allocate costs to all customers at this time. The decision defers a determination on whether and how to allocate costs to non-core customers until more information is gathered, including exploration of an exemption process for emissions-intensive and trade-exposed (EITE) customers which would be devised and approved through a separate application (as discussed further in Section 6.1.3.3). However, we do address this issue in the context of other scoped issues raised in the proceeding, and we find that this allocation may not affect the compliance obligation of any customer and should be further explored.

A "covered entity" is an entity whose direct emissions are large enough such that it is individually subject to Cap-and-Invest regulations. The non-core class includes covered entities as well as customers who are not covered entities; the gas utility covers the compliance obligation of the latter category and passes

[90] The Cap-and-Trade program has been renamed Cap-and-Invest.

[91] Scoping Memo Issue 5b.

on compliance costs in rates. Covered entities are exempt from GHG compliance costs in rates.

Joint Parties state that imposing costs on non-core customers would inappropriately force "covered entity non-core customers to pay for reducing the gas IOUs' Cap-and-Trade obligations without any corresponding reduction in their own Cap-and-Trade obligations."[92]

The Sempra Utilities assert that "[b]ecause there are no credits or revenues available for sharing, determining an equitable method to distribute the value resulting from any reduction in cap-and-trade obligations beyond the abovementioned method requires further discussion. Therefore, a working group should be established to delve into the specifics and nuances of this process."[93]

PG&E and SCGC agree with Joint Parties that any such allocation would not affect the compliance obligation of covered entity non-core customers, but in contrast, they see no issue with this, because "non-core customers will see savings from the reduction in GHG allowance costs from the above-market costs."[94]

We agree with Joint Parties, PG&E and SCGC. These parties are correct that the allocation of costs in rates would not affect covered entities' compliance obligations, since covered entities are directly regulated by CARB. But Joint Parties are incorrect to argue that this is inappropriate. The allocation would represent no inequity for these customers because the avoided GHG compliance cost is removed from the above-market costs before they are allocated. All value streams are accounted for before allocating these costs, and all customers paying

[92] Exhibit Joint-01 at 4.

[93] Sempra Utilities Opening Brief at 9.

[94] PG&E Opening Brief at 17, SCGC Opening Brief at 9.

the costs receive the emissions benefits commensurate with their own energy use.

5. Cost Allocation Authority

One of the fundamental questions discussed by parties in this proceeding is whether the Commission has the authority to allocate RGS above-market costs to all customers. No party disputes the Commission's authority to allocate these costs to bundled core customers. The core disagreement among parties regards whether we may require other groups to pay a share.

This section addresses this overall issue whether we have this authority. We subsequently address which specific customer groups should pay. We also separately address mechanisms for allocating and recovering costs from those groups.

Parties articulate two opposing views on this issue. Joint Parties, AReM/Shell, and Indicated Shippers deny we have this authority.[95] The utilities, TURN, Cal Advocates, and SBUA affirm that we do. SCGC and LCJA do not weigh in on the specific issue of our overall allocation authority.

5.1. Arguments Against the Commission's Authority to Broadly Allocate Costs

Joint Parties' fundamental argument that we lack the authority to allocate RGS above-market costs beyond the bundled core class rests on the distinction between bundled core versus unbundled core/non-core customers: utilities buy gas for the former and not the latter. Joint Parties see RGS costs as procurement costs incurred on behalf of bundled core customers. They frame this proceeding's central question as considering imposing "costs that gas [IOUs] incur in

[95] NRG's 2026 Supplemental Comments addressed this question, but these comments are accorded no weight because NRG's comments addressed issues outside the scope of those authorized by the 2026 Supplemental Ruling.

procuring biomethane for their bundled core customers on unbundled core and non-core customers who do not receive the utility-procured fuel.[96] Joint Parties argue that allocating costs to classes other than bundled core therefore "delinks the driver of the cost, procurement for bundled core customers, from the allocation of the cost" and that requiring "unbundled core and non-core customers to pay any portion of a procurement service they do not receive is unjust and unreasonable."[97]

Joint Parties cite to D.22-02-025 and argue that various elements of this decision conclusively demonstrate that the RGS program is a procurement program undertaken for bundled core customers. They point to the decision's recognition that we "cannot direct procurement decisions by entities that supply gas to non-core customers."[98] Joint Parties argue that D.22-02-025 "set specific biomethane procurement targets for each Joint Utility, focused solely on their bundled core customers."[99] Joint Parties cite to our order in that decision that the utilities shall procure RGS biomethane "solely on behalf of their bundled core customers."[100]

Overall, Joint Parties simply and consistently argue that the RGS program was created for the core customer class, that its costs are core procurement costs that should be paid only by that group, and that any allocation otherwise violates principles of cost causation and Pub. Util. Code Sections 451 and 453.[101]

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[96] Exhibit Joint-01 at 2.

[97] Exhibit Joint-01 at 3.

[98] D.22-02-025 at 8-9.

[99] Joint Parties Opening Brief at 11, and Joint Parties Supplemental Brief at 12.

[100] D.22-02-025 at 31.

[101] Joint Parties Opening Brief at 14, Joint Parties Supplemental Brief at 12-14.

Joint Parties largely do not distinguish between our authority to allocate costs to non-core customers and our authority to do so for unbundled core customers, making some of the same arguments verbatim in their Supplemental Briefs (focused on CTAs) as they did in earlier testimony and briefing addressing all customers.

In addition to these general authority arguments, Joint Parties also argue that allocating costs beyond bundled core customers would be "in contradiction of clear legislative intent not to cost-shift"[102] because such direction was ultimately removed from earlier drafts of SB 1440:

> In this instance, the Legislature specifically considered and ultimately rejected language directing that procurement costs in excess of the resale value of the biomethane procured would be allocated through a nonbypassable fixed charge assessed on both core and non-core customers. After many drafts in which the concept of a nonbypassable fixed charge was inserted and removed, the final form of the bill did not direct the Commission to implement a new nonbypassable fixed charge.[103]

Shell/AReM make the same overall arguments about our authority to allocate costs beyond the core group and similarly cite to the above legislative history, as well as that of AB 678 regarding CTAs, when arguing specifically against our authority to allocate costs to CTA customers.[104]

5.2. Arguments in Support of our Authority to Broadly Allocate Costs

PG&E, the Sempra Utilities, Southwest Gas, TURN, Cal Advocates, and SBUA argue that the Commission has the authority to allocate RGS above-

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[102] Exhibit Joint-01 at 14.

[103] Joint Parties Opening Brief at 30.

[104] Shell/AReM Supplemental Brief at 1-2.

market costs to all customers. PG&E argues that the Commission's authority here stems from Pub. Util. Code Sec. 701.[105]

They argue that there is no statutory prohibition for this allocation and that the costs are not core procurement costs, but rather the costs of achieving a state policy goal undertaken for and benefiting all customers.

SBUA encapsulates the main arguments made in support of our overall authority:

> The primary policy goal of SB 1383 (Lara, 2016) and SB 1440 is the development of a market for biomethane… Biomethane does not benefit customers and is not a mitigation of core customer-caused pollution. The biomethane molecules also do not flow to any particular customer class. The utilities have been tasked by the legislature to assist in solving a waste problem caused by other industries. The Commission set procurement targets based on the goal of utilizing sufficient biomethane to divert eight million tons of organic waste from landfills …The program, if effective, benefits all Californians, including core and non-core customers, by reducing on-energy sector greenhouse gas emissions. It would have been more fair for the above-market costs to be paid through general taxation rather than imposed specifically on gas customers. But that is not the mechanism created by the legislature.[106]

Overall, arguments in support of our authority rest on several key points. The first is that these are not procurement costs. The RGS program "exists to serve a statewide environmental objective"[107] and are "a cost of implementing California's public policy."[108] Therefore these costs are "different from any other bundled core gas procurement costs that 'are rightly, and justifiably, allocated to

[105] PG&E Opening Brief at 19.

[106] SBUA Opening Brief at 6-7.

[107] Sempra Utilities Supplemental Brief at 5.

[108] TURN Opening Brief at 2.

bundled core customers only'."[109] TURN reiterates: "[t]he allocation of biomethane procurement costs should not be determined as if they were merely another subset of procurement costs, but in recognition that they are costs incurred in order to advance California's public policy."[110]

SBUA responds to Joint Parties' characterization that allocating beyond bundled core is "like forcing the employees of one company to fund a pizza party they are not invited to at a different company"[111] by countering that "it would be more apt to say that gas utilities are funding a pizza party by methane polluters."[112]

Second, and relatedly, these parties argue that RGS program costs are *not* driven by the bundled core class, nor do the benefits accrue only to that class.

The Sempra Utilities argue that the GHG and emissions reductions benefits of biomethane are shared by all.[113] They note that the emissions which this program reduces are those from organic waste and not from gas customers' combustion:

> "In implementing SB 1440, the Commission acknowledged that the purpose for doing so was to reduce [short-lived climate pollutants (SLCPs)] that were being emitted by the state, as mandated by SB 1383. Because the SB 1383 mandate is to reduce [Short Lived Climate Pollutants, or SLCPs], which are generated by all, and not to meet emission reduction targets for core natural gas burn, the benefits are materialized for all California residents. As such, the above-market procurement costs should be allocated to all."[114]

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[109] TURN Opening Brief at 2.

[110] Exhibit TURN-1 at 2.

[111] Exhibit Joint-02 at 4.

[112] SBUA Opening Brief at 7.

[113] Sempra Utilities Opening Brief at 6.

[114] Sempra Reply Brief at 3.

Additionally, the Sempra Utilities point out that while the *commodity* costs can be seen as stemming from a service provided only to bundled core, this proceeding is focusing on allocation of the above-market costs, which reflect the delta between the cost of traditional gas and the cost of meeting an emissions policy:

> "Where the Joint Parties argue that the driver for the incurred cost of biomethane is to benefit bundled core customers, the assumption should only apply to the portion of the biomethane costs that is associated with the market price of traditional natural gas. It is reasonable to conclude that the market price portion of the cost of biomethane benefits only the bundled core customers who use that procured gas. The above-market portion associated with environmental benefits; however, has much broader cost drivers that are not isolated to bundled core customers. As clearly stated by the Commission, the benefits of those costs are shared by all customers."[115]

In short, the commodity costs remain with those served by them; the above-market costs reflect the cost of achieving state policy and the environmental benefits.

TURN adds that "[th]ere is no evidence that the utilities would procure any amount of biomethane if their decisions were made on the basis of 'traditional' procurement principles and practices."[116]

These parties also address the question of legislative intent and statutory direction. SBUA points out that legislative analysis addressed the removal of the nonbypassable charge language: it explained that "the proposed statutory

[115] Exhibit SCG/SDGE 2 at RMS-MWF-4.

[116] TURN Opening Brief at 2.

determination that costs 'shall be recoverable' conflict[s] with the requirement that costs be shown to be just and reasonable on a case-by-case basis."[117]

The Sempra Utilities argue that the legislative amendment process shows the legislature's recognition that the Commission already has and should retain cost recovery decision-making authority.[118] Sempra Utilities noted that in considering and rejecting earlier amendments regarding recovery of a nonbypassable charge from core and noncore customers and interconnection costs in SB 1440, the legislative history explicitly stated: "the CPUC should retain its authority to ultimately determine whether interconnection costs should be recovered from ratepayers" and that such logic applies as well to the later inclusion and removal of the nonbypassable charge.[119] Overall, SBUA adds, the amendment history of SB 1440 is better seen as "reflecting an active policy debate and the conventional give-and-take of different interest groups reflected in the political process"[120] rather than a clear indication of the Legislature's intent not to allow cost recovery beyond the core class.

In sum, PG&E, SBUA, TURN, the Sempra Utilities, and Cal Advocates argue that the legislative history removing the explicit cost recovery direction (and the absence of such language) does not preclude our authority to choose that outcome. TURN states that "silence is not a directive,"[121] and Cal Advocates asserts that the plain language of the statute is unambiguous; allocating costs to

[117] SBUA Opening Brief at 8-9.

[118] Sempra Utilities Opening Brief at 12.

[119] Sempra Utilities Opening Brief at 11-12, citing Senate Committee on Environmental Quality, SB 1440 Analyses at 8.

[120] SBUA Opening Brief at 9.

[121] TURN Opening Brief at 4, quoting D.20-08-43 regarding the Bioenergy Market Adjusting Tariff (BioMAT) program.

other groups does not violate the statute.[122] Multiple parties cite to the BioMAT program as an example of the Commission creating a nonbypassable charge without explicit statutory direction.[123]

5.3. The Commission Has the Authority to Broadly Allocate Above-market Costs

After consideration of the record, we conclude that the Commission has the authority to allocate RGS above-market costs to all customers.

Parties addressed this issue within the context of a shared understanding and agreement that, as a general matter, the Commission has authority to allocate procurement costs to bundled core customers because the utilities procure on their behalf. Those opposed to allocation beyond this group argue we do *not* have authority to allocate procurement costs to unbundled core or non-core customers because the utility does *not* buy gas for them.

The key distinction and point of disagreement, then, is whether RGS above-market costs are core procurement costs that are incurred for and driven by bundled core customers.

Joint Parties characterize these costs as being driven by the core customer class, and therefore object to other customers sharing those costs. They repeatedly urge us not to upend principles of cost causation by assigning costs to classes of customers who are not driving those costs.

Joint Parties are incorrect, and parties including TURN, Cal Advocates, and Sempra Utilities are correct. As enumerated below, a plain review of D.22-02-025 shows the RGS program was not created because of core procurement need, but instead to reduce emissions.

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[122] Cal Advocates Opening Brief at 5.

[123] Cal Advocates Opening Brief at 5.

First, we concluded there, "*To meet the state's methane and black carbon emission reduction goals*, the Commission should establish biomethane procurement targets and timetables for the state's investor-owned gas utilities to achieve the targets (emphasis here)."[124] The first Finding of Fact in D.22-02-025 states that RGS program targets shall be consistent with the state's waste diversion goal.[125]

Second, the levels of the RGS program short-term targets were set based on organic waste volumes, not bundled core (or any class's) demand:

> We adopt the Staff Proposal's recommended short-term target of procuring biomethane that achieves eight million tons of organic waste, including wood waste, diverted annually from California landfills, in accordance with Pub. Util. Code Section 651 (b). CalRecycle estimates that organic waste generates approximately 22 therms of biomethane per ton. Using this conversion factor, eight million tons of organic waste converts to 17.6 Bcf, which will serve as the short-term volumetric target for achieving the waste diversion target.[126]

Third, Joint Parties are correct that the RGS program medium-term target is characterized in the decision as a "bundled core customer procurement target."[127] But Joint Parties strip this quote from its context. The passage immediately preceding this language shows that the Commission set the target at that level because doing so would support SCLP reduction goals. We found that the medium-term target:

> "will encourage SLCP reduction in the waste sector while converging with state goals for decarbonizing the building sector.

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[124] D.22-02-025 Conclusion of Law 9.

[125] D.22-02-025 Finding of Fact 1.

[126] D.22-02-025 at 30.

[127] D.22-02-25 at 32.

> Therefore, we adopt a medium-term target in accordance with Pub. Util. Code 651 (b) for the Joint Utilities to collectively procure 72.8 Bcf by 2030 and beyond, which is approximately 12.2 percent of the Joint Utilities' annual bundled core customer natural gas demand, as forecasted in the 2020 California Gas Report for an average temperature year and adjusted to account solely for bundled core customers. This 12.2 percent medium-term bundled core customer procurement target may be referred to as a "Renewable Gas Standard" (RGS)."[128]

To reiterate in even simpler terms, we stated that the target is *based on* the waste diversion goal and then we *compared* the target to annual bundled core demand.

Fourth, when placed in this proper context it is equally clear that the ordering paragraph pertaining to the medium-term target is comparing the target to bundled core demand, not implying that the order is driven by that demand: the order states that each utility "shall procure each year an amount of biomethane equivalent to 12.2 percent of its own share of 2020 annual bundled core customer natural gas demand, excluding Compressed Natural Vehicle demand as noted in the California Gas Report (approximately 72.8 Bcf)."[129]

Fifth, the apportionment of RGS program targets was based on usage beyond bundled core. The utilities' individual shares of the overall short-term target were set *based on their proportionate Cap-and-Invest[130] allowance allocations*.[131] Each utility's allocation is based on the level of emissions from all the utility's

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[128] D.22-02-025 at 32.

[129] D.22-02-025 at 60.

[130] Formerly named Cap-and-Trade, this is California's GHG emissions reductions program, regulated by the California Air Resources Board (CARB).

[131] D.22-02-025 Ordering Paragraph 16.

customers who are non-covered entities under Cap-and-Invest, not just those from bundled core customers.

Sixth, D.22-02-25 discusses how RGS program targets will be adjusted in the future, "after taking into consideration progress made toward achieving the short-term target, additional analysis on technical and economic feasibility, market conditions, procurement rules, eligible time periods for contracts, and contract duration and outcomes from the Long-Term Gas Planning Rulemaking (R.20-01-007)."[132] None of those factors have anything to do with the procurement need or levels of demand from any customer class, because the RGS program was not established to meet those needs or sized based on them.[133]

Seventh, D.22-02-025 made conclusions regarding the authority to establish biomethane targets in SB 1440, and SB 1383's requirement for the State to reduce methane emissions by 40 percent below 2013 levels by 2030, tying these driving factors to the established program.[134] The RGS program was established to address these issues, not to meet procurement need.

Eighth, Joint Parties are correct that D.22-02-025 states, "[mirroring] the short-term target procurement standard, the Joint Utilities are responsible for procuring solely on behalf of their bundled core customers."[135] But it is not reasonable to interpret this statement as showing the Commission's decisive

[132] D.22-02-025 at 33.

[133] We note that D.26-04-044 in fact adjusted RGS program targets without any basis grounded in gas demand of any customer class. That decision changed the size of the program based on market progress, concerns about total RGS program costs, and other factors such as available amounts of diverted organic waste. It did not adjust program targets based on consideration of gas demand or procurement need. (*See* D.26-04-044 at 19-33)

[134] D.22-02-025 Conclusions of Law 1 and 2.

[135] D.22-02-025 at 33.

intent that only core bundled customers should pay or that we established the program "for" bundled core.[136] Within the full context we provide here, it is more reasonable to view this statement as recognition of the cost allocation structure in place at that time; we simply had not yet fully considered the non-core cost allocation question, so costs remained just with bundled core.

Ninth, and to directly follow on this point, D.22-02-025 plainly contains multiple references and an ordering paragraph regarding opening a proceeding (the instant rulemaking) to consider whether to allocate beyond bundled core.[137] Joint Parties ignore these references entirely, but a decision that orders further consideration of a question should not be read to have decided that question.

Tenth, Joint Parties cite to the Staff Proposal quoted in D.22-02-025 ("The Staff Proposal does not propose allocation of gas IOU biomethane procurement costs among non-core customers, noting that the CPUC cannot direct procurement decisions by entities that supply gas to non-core customers"[138]) as support for their position that the decision intended costs to be borne only by bundled core.[139] But they omit the language immediately afterward that discusses the potential for utilities to provide "proof and rationale" to propose allocating costs to non-core.[140] Again, this shows openness to the question of expanding cost allocation rather than the conclusion that doing so is improper.

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[136] Additionally, following this language, D.22-02-025 explains that the program targets will remain the same even as core demand decreases, showing again how the targets are unrelated to core procurement needs.

[137] D.22-02-025 at 28, 45, Ordering Paragraph 53.

[138] D.22-02-025 at 8.

[139] Exhibit Joint-01 at 3.

[140] D.22-02-025 at 9.

Eleventh, D.22-02-025 allocates the $1 million cost for a contract for a research study regarding biomethane constituents of concern to core and non-core customers, indicating our recognition of the broader responsibility for and benefit from that cost.[141]

Twelfth, and along those same lines, D.22-02-025 clearly shared other aspects of cost responsibility for biomethane beyond bundled core when it ordered the utilities to redirect GHG allowance revenues which fund the residential gas Climate Credit instead to biomethane: $40 million for pilot projects and $40 million for biomethane interconnection incentives.[142]

In sum, D.22-02-025 makes overwhelmingly clear that we established this program to achieve a state emissions reduction goal. The Commission made clear from its inception that the RGS program was created to solve an emissions and biowaste problem and was not sized based on expected demand of any customer class. D.22-02-025 also made clear that cost responsibility could broaden beyond bundled core. Arguments that D.22-02-025 both enacts a bundled core procurement program and enshrines its costs as burdening only that class improperly and incorrectly ignore its core findings.

It is accurate that we cannot direct non-core procurement, but we are not doing so. RGS above-market costs are not core procurement costs. We agree with TURN, SBUA, the Sempra Utilities, and Cal Advocates that we are allocating the costs of achieving state policy (less the market cost of commodity fossil gas). As these parties note, the RGS program will have emissions benefits for all gas customers.

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[141] D.22-02-025 at 37, Ordering Paragraph 34.

[142] D.22-02-025 at 46-49, Ordering Paragraphs 43 through 48.

Joint Parties are correct that customers who help drive and benefit from costs should pay them. In this case, that group is all customers. Therefore, allocating costs to all customers is in line with traditional cost causation and cost allocation principles.

We find that the RGS program was established for the purpose of reducing emissions and not the procurement need of any gas customer class. We additionally find that RGS program targets were set based on expected levels of diverted organic waste and not expected levels of gas demand. We find that RGS program benefits such as emissions reductions are not limited to the bundled core class. Therefore, it is reasonable to conclude that RGS program above-market costs are not typical procurement costs that would be paid only by bundled core customers and instead they are the costs of meeting state emissions reductions and waste diversion goals and should be borne by all customers.

Having established that these costs are not core procurement costs – refuting Joint Parties' main argument against this outcome – we turn next to the question of whether we otherwise have the authority to allocate costs accordingly.

Neither Joint Parties nor any other party identify any statute or code section that specifically prohibits our allocation of RGS above-market costs pursuant to our general authority and discretion. We find there is none.

The main arguments against our authority made in the record focus on legislative intent, and we address them here. However, we note that, while legislative intent is an important guiding consideration when evaluating matters of statutory authority, it is not dispositive.

We look directly to the bill analyses cited by parties as indicators of legislative intent. In April 2018, the Senate Committee on Energy, Utilities and

Communications and the Senate Committee on Environmental Quality initially reviewed versions of SB 1440 that would have required the CPUC to approve cost recovery from both core and non-core customers.[143] This included a requirement for a "fully nonbypassable fixed charge" or a nonbypassable demand differentiated fixed charge to the gas corporation's customers, including both core and non-core customers.

In May 2018, the Senate Committee on Appropriations stated that proposed sections of SB 1440 (specifically Subsection 2898.1) mandating the specific cost recovery would step into the Commission's role of determining costs are just and reasonable, and that such direction was unnecessary:

> "The intent of [Subsection 2898.1(e)(1)] is unclear. Under existing law, a utility cannot recover any expenditure from ratepayers unless it is deemed a just and reasonable expense by the CPUC. If the intent of this section is to make clear that the CPUC should consider allowing utilities to recover implementation costs it deems just and reasonable, staff recommends that this section be stricken because it is duplicative of current law.
>
> If this section intends to force the CPUC to allow the utilities to recover any just and reasonable expenditure incurred for some or all implementation activities, then staff recommends that the bill is amended to clearly state which activities or types of activities require recovery from ratepayers. If this is the case, the committee may wish to consider whether it is appropriate or prudent for the Legislature to *effectively conduct rate-setting without benefit of all the information covered in the general rate case* (the process through which the allowable rate of return for shareholders and rates for ratepayers is decided). It may further wish to consider the impact the decision to mandate rate-recovery in statute will have on the interpretation of

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[143] April 9, 2018 Senate Committee on Environmental Quality analysis of SB 1440 at 3, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB1440

> current and future statutory mandates on utilities. (Emphasis added)[144]

By August, the cost recovery direction was no longer in SB 1440, and did not appear in the final version of the bill.

We disagree with Joint Parties that this removal indicates that the Legislature intended in SB 1440 to prevent cost recovery from ratepayers, based on the clear statements in bill analyses that indicate this removal was intended to preserve the Commission's broad discretion over ratesetting.

Similarly, our review of AB 678[145] shows the Legislature was aware of the Commission's consideration of the imposition of costs on all core and non-core customers in this current rulemaking and did not intend AB 678 to prejudice that determination.

In July 2023 – seven months after the initiation of this rulemaking – Senate bill analysis acknowledged the instant proceeding's consideration of a nonbypassable charge:

> *Without prejudging the CPUC's future determination on whether to utilize a nonbypassable charge*, the author and committee may wish to amend this bill to explicitly authorize the CPUC to provide CTAs the option for gas corporations to procure the biomethane on behalf of the CTA, with the costs paid for by the CTA or their customers.[146] (emphasis added)

The final version of AB 678 did include such a provision, and did not specify cost recovery.

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[144] April 30, 2018 Senate Committee on Appropriations analysis of SB 1440 at 4, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB1440

[145] *See* a description of the provisions of AB 678 in Section 6.1.1.

[146] July 3, 2023 Senate Committee on Energy, Utilities and Communications analysis of AB 678 at 6-7, available though incorrectly labeled with a date of June 30, 2023, at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240AB678

Additionally, Senate floor analysis later stated:

> In addition to the many cost-containment provisions incorporated into the decision to adopt biomethane procurement requirements, including revisiting the medium-term targets in 2025, the *CPUC also acknowledged the potential to utilize a nonbypassable charge* collected from all natural gas customers within the service territories of the large gas corporations, which would include CTA customers, as an alternative approach to require procurement compliance and will be considered in a future proceeding.[147]

Joint Parties argue that, with AB 678, the Legislature had a chance to direct recovery from all customers, and the fact that it did not means it intended to prevent this outcome. But the legislative history shows the Legislature was aware of the options being considered here and specifically intended to preserve our decision-making role in the matter. As SBUA puts it, the legislative changes "show an ultimate legislative choice to avoid deciding an issue better left to the Commission's discretion."[148]

We find that the legislative history for SB 1440 and AB 678 demonstrates that the legislative intent behind the absence of the direction for cost recovery was to preserve the Commission's discretion on the proper cost allocation of RGS above-market costs.

It is reasonable to conclude that the Commission has the authority to allocate RGS above-market costs to all customers pursuant to our discretion.

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[147] August 16, 2023 Senate Floor analysis of AB 678 at 7, available at https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=202320240AB678

[148] SBUA Opening Brief at 9.

6. Allocation of Above-market Costs to Additional Groups

As discussed above, we have the authority to allocate RGS above-market costs as we find reasonable. We now address which specific customer groups in addition to bundled core customers will share in the RGS above-market costs.[149]

As directed in D.22-02-025, bundled core customers are currently the only customers paying RGS above-market costs. This proceeding considers whether three other groups should also have a share of these costs allocated to them: unbundled core customers (customers of Core Transport Agents or CTAs), third-party gas marketers, and non-core customers.

CTAs are private, non-utility business entities that buy natural gas on behalf of residential and small business customers. CTAs must demonstrate operational, technical, and financial qualifications to register in California, but do not own or operate gas infrastructure nor provide delivery services. Customers of the gas IOUs can switch to CTAs, whose rates and many other practices are not regulated, but remain delivery customers of the IOU.

SB 656 (Wright, 2013) established CTA registration and consumer-protection requirements, and although the CPUC does not regulate CTA rates, it monitors marketing practices and customer complaints and may impose penalties for violations of applicable requirements.

Third-party marketers are private entities that provide procurement services for non-core customers. In addition to purchasing the gas commodity for contracted non-core customers, third-party marketers can also provide a range of services to manage customers' gas portfolios.

[149] LCJA advocates for allocating costs to utility shareholders in its Opening Brief (at 5-6). Such direction would be inconsistent with the ratepayer cost recovery authorization in D.22-02-025 and is outside the scope of this proceeding.

Non-core customers are generally larger-volume gas consumers than core customers. They procure their own gas (or engage a third party to do so) and pay the utility for transportation services and other costs. SCGC estimates there are approximately 1,020 non-core customers in California, and they consume roughly 60 percent of all the gas supplied by the utilities.[150]

6.1.1. Unbundled Core Customers

This section addresses whether unbundled core customers served by CTAs (CTA customers) should pay a share of RGS above-market costs. We have already addressed questions of our authority to make this allocation.

As previously discussed, in 2023 the Legislature passed AB 678 to incorporate CTAs into the biomethane structure established by AB 1440.

AB 678 amended Pub. Util. Code Section 651 in three key respects. First, it amended Pub. Util. Code Sec. 651(a) to require the Commission to also consider adopting proportionate shares of biomethane targets for CTAs (whereas SB 1440 regarded only the gas utilities). Second, it added Pub. Util. Code Section 651(b)(4) to specify that, if the Commission allocates goals to CTAs, it shall also authorize CTAs to contract with gas utilities to procure biomethane on their behalf, with all costs paid for by the CTA "and any environmental attributes allocated in a fair and transparent manner."

Third, AB 678 created Pub. Util. Code Sec. 651(c) which reads in full:

> "The [C]ommission shall initially allocate each core transport agent their proportional share of the existing biomethane procurement targets established by [C]ommission Decision 22-02-025 (February 24, 2022) Decision Implementing Senate Bill 1440 Biomethane Procurement Program. This subdivision shall not prohibit the [C]ommission from establishing additional biomethane targets."

[150] Exhibit SCGC-01 at 8-9.

AB 678 was considered and adopted after the initiation of this rulemaking, and the scope of this proceeding does not include consideration of allocating biomethane procurement *targets* to CTAs. However, our scope does include considering whether to allocate any share of RGS above-market costs to customers served by CTAs.

Prior to Supplemental Briefs, parties generally addressed whether CTA customers should share in these costs without differentiation from non-core customers. In other words, testimony and briefs largely referred to CTA and non-core customers jointly and did not make distinctions between them. The CTA Ruling focused specifically on this group, so responsive supplemental briefs addressed them in particular. The CTA Ruling sought input on whether CTA customers should be allocated RGS above-market costs; whether such an allocation should be interim and whether it would satisfy AB 678; the appropriate allocation mechanism; and other questions.

6.1.1.1. Arguments Against Cost Allocation

Indicated Shippers and Shell/AReM argue that AB 678 prohibits the Commission from allocating costs to CTAs, positing that in requiring we consider allocating CTAs a portion of the targets, it precluded us from allocating to their customers any of the utilities' RGS above-market costs. Pointing to the statutory construction of Pub. Util. Code Section 651 as amended by AB 678, Indicated Shippers assert that we must allocate targets "initially," meaning *before* allocating costs, and that CTA customers can only bear costs after their CTA contracts with a gas utility for biomethane.[151]

[151] Indicated Shippers Supplemental Brief at 17-18.

On a policy basis, these parties make many of the same arguments against allocating costs to CTA customers as they previously did regarding non-core/unbundled core generally: that RGS above-market costs are core procurement costs and therefore their allocation to CTA customers is unjust and unreasonable.[152] We note but do not reiterate all those arguments here. Similarly, Indicated Shippers makes the same arguments regarding legislative intent as they did earlier, referring to the same amendments removing cost recovery direction.[153] Indicated Shippers argues that the legislature "again chose" not to direct cost recovery, because when it revisited biomethane with AB 678 it did not include such direction.[154] Shell/AReM argue that allocating costs to CTA customers "runs afoul" of legislative intent behind AB 678, which provided CTAs a choice between self-procurement and contracting with a utility.[155]

6.1.1.2. Arguments Supporting Cost Allocation

PG&E and the Sempra Utilities argue the opposite: that the functional intent of AB 678 was to ensure CTA customers share in RGS program costs and that until the Commission explicitly addresses their share of the target, it is reasonable, equitable, and necessary to allocate their share of any such costs. The utilities further argue that there is no explicit or intended limitation in statute to our discretion with respect to cost allocation. The utilities make many of the same arguments regarding our authority to allocate costs as they did previously, including references to prior programs and decisions they view as informative here; we do not reiterate those here. The utilities also view CTA allocation as

152 Indicated Shippers is one of the Joint Parties.

153 Indicated Shippers Supplemental Brief at iv.

154 Indicated Shippers Supplemental Reply Brief at 5.

155 Shell/AReM Supplemental Brief at 6.

appropriate for all the same reasons: that CTA customers should pay a share since these are emissions reduction policy costs from which they benefit.

PG&E proposes that this allocation should be interim, remaining in place until 1) the Commission allocates targets to CTAs and 2) the expiration of utilities' biomethane contracts executed prior to that directive.[156]

The utilities have repeatedly argued that failing to allocate costs broadly, and to CTAs in particular, is inequitable, poses risks of consumer harm, and threatens to undermine the success of the RGS program.

The Joint Utilities assert that if CTA customers "are not equitably allocated the above-market costs of biomethane procurement and transmission, this could contribute to undermining the success of the Biomethane Procurement Program" and that:

> bundled core customers will be incented to switch to CTAs due to high biomethane procurement costs, and continued migration of customers to CTAs results in remaining bundled core customers bearing an increasingly larger share of the costs. This would ultimately result in the failure of the biomethane procurement program and could be avoided by creating an equitable cost allocation to all customers, including CTAs' customers, prior to costs being incurred.[157]

The Sempra Utilities reiterate this risk in Supplemental Briefs. Such a "systemic price discount" could "lead to a rush away from bundled service and to CTA service."[158] They warn that this increased burden on remaining bundled customers would place "greater burden on those with limited ability to opt out,

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[156] PG&E Supplemental Brief at 6-7.

[157] Response of Gas Utilities to OIR to Address Biomethane Procurement Cost Allocation (Joint Response to OIR) at 5.

[158] Sempra Utilities Supplemental Brief at 3.

such as low-income or less energy-literate customers."[159] These utilities urge us to allocate costs more broadly to protect bundled gas customers from an inequitable and growing burden: "[if] CTA customers who often have more procurement flexibility and access to market alternatives are exempted from sharing in above-market biomethane costs, the remaining costs are absorbed by a shrinking base of bundled core customers."[160]

PG&E and the Sempra Utilities also separately argue that cost allocation to CTAs is essential to the success of the RGS program.[161]

The Sempra Utilities assert that this situation would affect environmental and social justice (ESJ) communities: because the bundled customer group has a disproportionate share of low-income and vulnerable populations[162] allocating costs more broadly "can help protect ESJ communities from rate shocks and preserve fairness across the system."[163]

Cal Advocates, TURN, and other parties who support allocating to all customers did not file supplemental briefs specifically addressing the CTA cost allocation. We separately address their arguments in the section below regarding non-core, but note here that these parties included unbundled core in their arguments.

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[159] Sempra Utilities Supplemental Brief at 5.

[160] PG&E Supplemental Brief at 4, Sempra Utilities Supplemental Brief at 7.

[161] PG&E Supplemental Brief at 8.

[162] Sempra Utilities Supplemental Brief at 7.

[163] Sempra Utilities Supplemental Brief at 7.

6.1.1.3. Unbundled Core Cost Allocation

After careful consideration of the record we conclude that unbundled core customers (CTA customers) should be allocated RGS above-market costs. We first discuss issues of our authority.

Section 5 discusses why we have the authority to make this allocation. Regarding the specific arguments made in Supplemental Briefs regarding AB 678 construction and legislative intent, we conclude that there is neither a limitation on our authority nor legislative intent contrary to allocating costs to CTA customers.

Indicated Shippers is incorrect in arguing that the language of Pub. Util. Pub. Util. Code Section 651(c) prohibits this allocation or restrains the order in which we may direct it. Again, that final subsection of Section 651 was created by AB 678 and reads in full:

> "The [C]ommission shall initially allocate each core transport agent their proportional share of the existing biomethane procurement targets established by [C]ommission Decision 22-02-025 (February 24, 2022) Decision Implementing Senate Bill 1440 Biomethane Procurement Program. This subdivision shall not prohibit the [C]ommission from establishing additional biomethane targets."

Indicated Shippers provides no rationale for its assertion that the word "initially" in this section means that CTA targets must be allocated before we allocate costs in the instant proceeding. In the other subsections, it is clear that we are required to consider allocating targets to CTAs, but Pub. Util. Code Section 651 does not discuss the instant proceeding or cost allocation at all; there is no reason to conclude that "initially" means the targets must precede allocation. It is more reasonable to conclude instead that Pub. Util. Code Section 651(c) requires that, if we allocate CTAs targets, we should initially-- *as a starting point* – allocate them a share of the previously-established total RGS program targets.[164] Reinforcing this interpretation is the final sentence of the subsection, which specifically clarifies we are able to supplement those "initial" targets. It is reasonable to conclude that Pub. Util. Code Section 651 does not require the Commission to consider allocating targets to CTA customers before allocating RGS above-market costs pursuant to our authority.

We agree with the utilities that allocating costs to CTAs is not in conflict with, and does not violate, AB 678. As previously stated, the statute does not address cost allocation, and legislative history affirms that these issues were intentionally left to us. At the same time, we clarify that our decision today is not a fulfillment of the amendments from AB 678. This decision does not address the requirements established by AB 678; we have yet to consider target allocation for these entities as required by Pub. Util. Code Section 651. Our decision here does not impede that consideration.

We concluded above that RGS above-market costs are not typical procurement costs that would be paid only by bundled core customers and that instead they are the costs of meeting a state emissions reduction goal and should be borne beyond the bundled core class. We have also already established our authority to make this allocation. In light of these conclusions, we conclude it is reasonable to allocate above-market costs to unbundled core customers.

Additionally, we are concerned about the potential raised by the utilities for customer flight to CTAs from utilities if CTAs are exempt. It is reasonable to conclude that such a structure could drive reductions in the number of customers

[164] We also note that D.26-04-044 revised the targets in D.22-02-025, so the statute now refers to out-of-date targets; we expect that future consideration and allocation of proportional CTA targets will be based on the revised targets, not the ones in the decision that is cited in Pub. Util. Code Section 651.

remaining to pay the costs, increasing costs for those who remain. We particularly note the utilities' point that the bundled core class contains more residential, vulnerable, and ESJ customers than other classes, and take seriously our responsibility to protect these consumers.

We raise here a relevant provision in statute. Pub. Util. Code Section 985 relates to CTAs and core gas consumer protections, and provides the Commission authority to establish minimum standards for CTAs. Subsections (a) through (g) regard confidentiality, disconnects and reconnects, change in providers, written notices, billing, meter integrity, and customer deposits. Section 985(h) regards additional protections and reads: "Additional protections. The commission or the governing body may adopt additional core gas consumer protection standards that are in the public interest."[165] This final subsection provides the Commission broader discretion to adopt core gas consumer protections, and we previously exercised that authority in D.15-10-050 when we required PG&E to procure pipeline capacity on behalf of CTA customers.[166]

The Commission's authority under Pub. Util. Code Section 985(h) provides separate and primary basis and authority for our cost allocation here. Ensuring that unbundled core customers share in these costs is not just reasonable because of the nature of the costs themselves, but also because it provides protection to core customers. Continuing to confine RGS above-market costs only to bundled core would enshrine an unequal playing field between gas utilities and CTAs and could harm core customers as a result.

[165] Pub. Util. Code Section 985(h).

[166] D.15-05-050 at 32 and Conclusion of Law 9.

Next, we address the question of whether cost allocation to CTAs should be interim, pending the consideration of CTA targets as required by Pub. Util. Code Section 651. The basic approach proposed by PG&E is reasonable and fair: after we have considered allocating targets to CTAs (and if we allocate targets to them), those customers would only pay costs of contracts incurred before that allocation. There is no "double charging" in this construct. CTAs' proportionate targets would already be reduced by any interim procurement; CTA customers would continue to pay interim costs until those contracts end; and CTA customers would additionally pay only incremental costs from CTA procurement.

While Indicated Shippers argues that the cost allocation we adopt here strips CTAs of their procurement autonomy, we disagree; any CTA is currently quite free to procure biomethane (or seek to contract with a utility for a share of its procurement) should it wish to do so. Any CTA biomethane procurement with accompanying RTCs would contribute towards any eventual CTA target, so we do not see any double-charging concern or impingement on CTA autonomy.

This decision orders the utilities to allocate RGS above-market costs to all core customers.

6.1.2. 3rd party marketers

The Scoping Memo asked: "Should some portion of above-market costs be allocated to third-party marketers who buy and sell for non-core customers?"[167]

[167] Scoping Memo Issue 4b.

Parties reached agreement that biomethane procurement cost allocation should not apply to third-party marketers.[168] We agree with parties and do not allocate costs to third-party marketers.

6.1.3. Non-core customers

Having previously resolved that we have the authority to allocate costs to non-core, we turn to the question of whether we should.

6.1.3.1. Arguments Against Cost Allocation

In addition to the arguments related to our authority, which we have already addressed, parties made various points that are set out below.

Joint Parties reiterate the arguments about the non-core allocation undermining "traditional cost causation and cost allocation principles," and violating decades of separation between non-core and core customers' cost responsibilities since energy deregulation in the 1990s.[169]

SCGC expresses profound concerns about the high costs of the RGS program, urging us to reconsider the program entirely; it opposes allocating costs to electric generators (a subset of non-core) because this would impose unbearable and unacceptable costs on electric ratepayers and constitute an unreasonable cost-shift from gas to electric ratepayers.[170] SCGC further poses that allocating costs to electric generators would directly undermine electrification efforts.[171]

Further, SCGC also argues that non-core customers do not experience benefits in proportion to the costs they would pay, noting that there are about

[168] Joint Case Management Statement, Attachment B.

[169] Joint-02 at 7.

[170] Exhibit SCGC-01 at 2, 9.

[171] SCGC Opening Brief at 13-14.

1,000 non-core customers in the state, compared to about 5.9 million core customers.[172] Under some of the allocation methodologies proposed, SCGC asserts, non-core customers would pay 62.1 percent of the RGS above-market costs, and it is not reasonable to suggest that "the 1,020 non-core customers somehow accrue 1.64 times (62.1 percent/37.9 3 percent) as much benefit from avoiding the social cost of SLCP emissions as do the 5.9 million core customers."[173]

Joint Parties state that imposing costs on non-core customers would inappropriately force "covered entity[174] non-core customers to pay for reducing the gas IOUs' Cap-and-Trade[175] obligations without any corresponding reduction in their own Cap-and-Trade obligations."[176] This is because RGS program biomethane would reduce the utility's compliance obligation but would not affect the compliance obligation of covered entity non-core customers.

Joint Parties similarly explain that the non-core allocation would undermine California's GHG emissions policies, by reducing the viability of covered entities' option to contract for their own biomethane procurement and reduce their own GHG compliance obligation.[177] Further, imposing these enormous costs could force some customers to move out of California, running

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[172] Exhibit SCGC-01 at 8-9.

[173] Exhibit SCGC-01 at 8-9.

[174] A "covered entity" is an entity whose direct emissions are large enough such that it is individually subject to Cap-and-Invest regulations. The non-core class includes covered entities as well as customers who are not covered entities; the gas utility covers the compliance obligation of the latter category and passes on compliance costs in rates. Covered entities do not pay GHG compliance costs in rates.

[175] Now called "Cap-and-Invest."

[176] Exhibit Joint-01 at 4.

[177] Joint Parties Supplemental Comments at 7.

contrary to Cap-and-Invest statutory requirements for CARB to minimize "emissions leakage."[178] Joint Parties list multiple statutory requirements regarding emissions leakage:

> Health and Safety Code Section 38562(a) (7) (mandating consideration of "the effect of these regulations on affordability, cost-effectiveness, minimization of leakage in California,"); *see also* Health and Safety Code Section 38562(c)(2)(A)(V) (ordering consideration of "the potential for environmental and economic leakage" in the setting of a price ceiling); *see also* Health and Safety Code Section 38562 (c)(2)(G); *see also* Health and Safety Code Section 38562 (c)(2)(J)(directing a report by Dec. 31, 2025 on implementation progress as well as "the leakage risk posed by the regulation", with inclusion of "recommendations to the Legislature on necessary statutory changes to the program to reduce leakage including the potential for a border carbon adjustment").[179]

These parties further address the issue of impacts of allocation on non-core customers who are emissions-intensive and trade-exposed (EITE). EITE entities are companies that have high GHG emissions relative to unit of output and are exposed to broader trade pressures. As D.12-12-033 explained,

> "Trade exposure is a measure of the degree of competition a sector faces from entities operating outside of the Cap-and-Trade program and the associated ability of consumers to shift demand to those providers that do not bear any carbon costs. Without assistance, the competitiveness of industries that are both highly emissions-intensive and trade-exposed has the potential to be negatively affected relative to competitors that do not face similar GHG emission reduction requirements.[180]

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[178] "Emissions leakage" refers to emissions from covered entities moving out of state; while this technically reduces California's GHG emissions, this is offset by increased emissions elsewhere, and such an outcome is antithetical to the goals of Cap-and-Invest.

[179] Joint Parties Supplemental Comments at 8.

[180] D.12-12-033 at 18.

Joint Parties also note that the Commission's Industry Assistance Credit (provided to non-core customers who are not covered entities but are designated as EITE) is intended to help prevent emissions leakage, and allocating RGS above-market costs to these customers would undermine this effort as well as CARB's directives.

Both the 2026 Supplemental Ruling and the Second Supplemental Ruling sought input on EITE impacts and emissions leakage risks, as well as potential processes to reduce these risks or specifically exempt EITE non-core customers from costs.

In response, Indicated Shippers, SCGC, Coalition for Renewable Natural Gas and the Sempra Utilities affirmed that allocating costs to EITE non-core customers would create risk of emissions leakage.[181] Indicated Shippers urges us to take this risk seriously:

> The risk of leakage is not theoretical. California has experienced the closure, downsizing, or relocation of multiple energy-intensive industrial facilities in EITE-designated sectors, including petroleum refining, cement production, and beverage manufacturing. The last steel mill in California closed in 2020, leaving California to import 100% of its steel. These outcomes have resulted in the displacement of industrial production and associated employment opportunities and tax revenues from California to other jurisdictions, without a corresponding reduction in global GHG emissions.[182]

Coalition for Renewable Natural Gas supports "the establishment of sectoral-specific programs for EITE industries and believe[s] that biomethane will be a prime candidate to decarbonize such industrial sectors."[183] It

[181] Indicated Shippers Second Supplemental Comments at 6; Sempra Utilities Second Supplemental Comments at 3; SCGC Second Supplemental Comments at 4-5.

[182] Indicated Shippers Second Supplemental Comments at 6-7.

[183] Coalition for Renewable Gas OIR Comments at 4.

additionally suggests that "a phased in approach extending coverage of the biomethane charge over time—perhaps from coverage of only non-EITE customers initially… could be considered."[184]

Indicated Shippers (while still opposed to any non-core allocation) agrees that EITE customers should be exempt to prevent emissions leakage. They assert we do not need further process to develop such an approach because the utilities already have all the billing functionality and information on EITE customers that they would need to exempt them.[185] They urge us to adopt such an exemption now.

Contrastingly, SCGC does not concede or agree with an EITE exemption process, reiterating that the solution is not to allocate to non-core at all and rely on the cost containment mechanisms in D.26-04-044 to mitigate impacts on core customers.[186]

6.1.3.2. Arguments Supporting Cost Allocation

As with the arguments against, most of the arguments in support of allocating to non-core have already been described and addressed in Section 5. We note but do not reiterate them here.

PG&E, the Sempra Utilities, Cal Advocates, and TURN assert there are policy similarities and equivalent cost allocation logic between the RGS program and "nearly identical" programs implemented on the electric side such as BioMAT and BioRAM, which both focused on procurement of bioenergy; BioRAM in particular resulted from an Executive Order and required procurement of expensive bioenergy made from excess tree waste to reduce

[184] Coalition for Renewable Gas OIR Comments at 4-5.

[185] Indicated Shippers Second Supplemental Comments at 4-6.

[186] SCGC Second Supplemental Comments at 5.

forest fire risk and emissions.[187] These parties argue that the Commission determined when allocating costs from those programs that it was reasonable to "ensure equitable cost-sharing for programs tied to statewide environmental benefits" and that we should do the same here.[188]

PG&E agrees[189] with the Sempra Utilities that "the goals of cost allocation in this context should be to align cost recovery with all customers who are receiving benefits, while maintain[ing] equity and fairness and ensuring the program has scalability to allow for high levels of decarbonization required to reach California's long-term climate goals."[190]

The Sempra Utilities, as previously noted in regards to benefits quantification issues, see at least five different kinds of benefits from the RGS program that accrue to all, and also points out that because "GHG emissions are proportional to gas consumption" and "the non-core class consumes most of the gas in the state and therefore causes the most emissions from gas consumption, it should particularly share these costs.[191]

Some of these parties agree that an EITE exemption may be needed in the event we allocate to non-core. The Sempra Utilities state, "The Commission should allow a formal stakeholder process to develop EITE exemptions, using criteria aligned with existing CPUC frameworks, such as energy intensity, trade exposure, cost impact thresholds, and risk of emissions leakage."[192] They

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[187] Sempra Utilities Opening Brief at 10; PG&E Supplemental Reply Brief at 6; Exhibit TURN-1 at 3; Cal Advocates Opening Brief at 5.

[188] PG&E Reply Brief at 6.

[189] PG&E Opening Brief at 13.

[190] Exhibit SCG/SDGE-1 at RMS-MWF-5.

[191] Sempra Utilities Opening Brief at 6-7.

[192] Sempra Utilities Second Supplemental Reply Comments at 2.

recommend this process includes an application or similar mechanism for stakeholders to submit supporting data so the Commission can determine the appropriate relief "such as partial exemptions, cost caps, or phased-in rate treatment."[193]

In stark contrast to Joint Parties' claim that we can and should establish them now, PG&E believes the record is weak on EITE exemptions:

> The record of this proceeding only has minimal discussion relating to EITE and emissions leakage. The current record does not provide sufficient evidence that allocating biomethane procurement costs to non-core customers would materially increase emissions leakage or that existing CARB protections are insufficient to address that risk. Furthermore, the record does not provide a clear assessment of the rate impacts, cost-shifting implications, or implementation complexity associated with establishing an exemption.[194]

Regarding SCGC's argument that a non-core allocation would have unreasonable impacts on electric generators, and therefore electric ratepayers, PG&E responds: "SCGC's arguments are flawed because these arguments assume that biomethane procurement and building/transportation electrification are dependent on each other and do not allow for the possibility that biomethane procurement and building/ transportation electrification efforts can coexist and complement each other."[195] PG&E further cites to CARB's Scoping Plan and its description of how multiple efforts can help decarbonize industrial facilities by "displacing fossil fuel use with a mix of electrification, solar thermal heat, biomethane, low- or zero-carbon hydrogen, and other low-carbon fuels to

[193] Sempra Utilities Second Supplemental Reply Comments at 3.

[194] PG&E Second Supplemental Reply Comments at 3.

[195] PG&E Reply Brief at 17.

provide energy for heat and reduce combustion emissions."[196] SBUA similarly argues that electric generators should not be exempt.[197] Joint Parties do not particularly weigh in on an electric generator exemption, restating their overall position that all non-core customers should be exempt.

6.1.3.3. Potential for Emissions Leakage Needs Further Consideration

As previously addressed, all customers should share in RGS above-market costs. However, after considering the full record, we conclude that is reasonable to further consider how to reduce the risk of emissions leakage when allocating RGS above-market costs to non-core customers. Therefore at this time we do not enact the allocation of these costs to the non-core class, and we direct further processes to consider how to implement this allocation while minimizing emissions leakage risks.

Although we have the authority to allocate these costs to non-core, and although we have found that customers beyond bundled core should share in the cost responsibility, several critical factors prevent us from concluding that the non-core allocation should be enacted in this decision.

First, we are profoundly concerned about such an allocation resulting in emissions leakage. PG&E is correct that we do not have evidence regarding the extent of that risk, but we cannot conclude there is zero risk. Parties have noted the risk of pushing industrial customers out of state. Because a non-core allocation based on proportional gas consumption would assign roughly 60% of all RGS above-market costs to only about 1,000 customers,[198] and because exact

[196] PG&E Reply Brief at 17, citing to the 2022 CARB Scoping Plan at 207.

[197] SBUA 2026 Supplemental Comments at 3.

[198] 2025 California Gas Report Supplemental at 9.

costs are impossible to predict but may be significant, it is reasonable to conclude this allocation entails some amount of emissions leakage risk. The RGS program was established to reduce emissions. It would be profoundly illogical to charge non-core customers for an emissions reduction program in a way that directly results in emissions leakage. The statutory requirements cited by Joint Parties regarding the extreme circumspection on emissions leakage apply directly to CARB, not the Commission, but we agree that it would not be prudent to undermine them. For these reasons we must be extremely cautious here.

Second, we do not have sufficient information to fully assess the emissions leakage risk. The issue was not extensively discussed until the final supplemental rulings and comments in the spring of 2026, and the specific question of an EITE exemption for non-core customers was not addressed at all until those filings. We conclude that due to the severity of the risk here, it would not be reasonable to allocate costs to non-core customers without additional information to allow us to evaluate the extent of the risk and whether it can be reduced.

Third, the record shows that there is the technical potential for exemptions that could reduce emissions risk, but that such an undertaking would be complex.

Indicated Shippers asserts that we have all the information and capability to establish exemptions now, but its support for these assertions crumbles under closer scrutiny. CARB does administer EITE designations, and the utilities do already identify covered entities (who take care of their own compliance obligations) so that they can exempt them from GHG compliance costs in rates. But here Indicated Shippers appears to conflate *covered* entities with *EITE* entities. In fact a customer could be EITE but not a covered entity (and could also be a covered entity that is not designated EITE). So the process is not as simple as directing the utilities to exempt all covered entities.

To respond to Indicated Shippers' assertion that the Industry Assistance program is an equivalent proxy to implement a gas non-core EITE customer exemption, we first provide brief background.

As created in D.14-12-037, CA Industry Assistance is an electric investor-owned utility (IOU) customer credit program. The electric IOUs administer this assistance via bill credits, similar to the process of providing residential Climate Credits (and both credits stem from the same funding source: the electric IOUs' auction revenues from allowances allocated to them by CARB).[199] The Industry Assistance program relies on specific six-digit North American Industrial Classification System (NAICS) codes to calculate customer credit amounts. NAICS codes classify many different types of industries and are used by CARB as part of its Cap-and-Invest regulation to identify which electric customers qualify for assistance due to their EITE nature. If a facility is an electric IOU customer and operates in a qualifying six-digit NAICS code, it is considered EITE and receives an annual CA Industry Assistance credit.[200]

However, Joint Parties do not provide the context for CARB's determination of which NAICS codes qualified as EITE, nor address the Commission's acknowledgement that CARB's determination was incomplete. CARB's process to identify EITE NAICS codes was described by the Commission in D.14-12-037:

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[199] D.14-12-037; see D.26-04-036 for the most current background on the residential Climate Credit.

[200] D.21-08-026 at 27.

> [C]ARB identified which industrial sectors qualify for Industry Assistance by conducting a study that classified industries by high, medium or low leakage risk...The scope of this study was limited to industrial sectors in which at least one entity had a direct compliance obligation under the Cap-and-Trade Regulation (i.e. an entity that annually emits more than 25,000 MTCO2e).[201]

Covered facilities meeting the threshold under the Cap-and-Invest program are generally very large; there are only approximately 400 covered facilities in California.[202] Practically, this means that medium- and small-sized industry customers that operate in an industry that did not have at least one covered entity at the time CARB conducted its study were not evaluated by CARB and therefore will not appear on CARB's EITE NAICS list. It is entirely possible that many other NAICS codes would qualify as EITE if subjected to the same study process.

While focusing on only large facilities with direct obligations under Cap-and-Invest are appropriate study parameters for CARB, that limitation is less suited for the situation contained in this Decision, which would impact all non-core customers irrespective of emissions quantity. The Commission has previously recognized that small- and medium-sized customers can also be EITE, at least for the purposes of indirect emissions:

> Applying a more general reading of "emissions-intensive and trade-exposed" under § 748.5(a), we find that the EITE designation for the purposes of indirect emissions should extend to customers in industries identified by ARB as qualifying for Industry Assistance, but with emissions levels less than 25,000 MTCO2e. Such entities, although they do not have a direct compliance obligation under the Cap-and-Trade regime, presumably also face similar leakage risk as

[201] D.14-12-037 at 9.

[202] "2026 Updates to California's Cap-and-Invest Program Fact Sheet," at https://ww2.arb.ca.gov/sites/default/files/2026-04/nc-CAI_FS_2026.pdf

> their larger covered peers within a given industrial sector as a result of their indirect emissions, which could put them at a competitive disadvantage with entities outside of California.[203]

The Commission sought to address the limitations of the CARB EITE study parameters by conducting a supplemental EITE study looking at a larger variety of industries operating in California,[204] resulting in D.14-02-003 outlining how such a study would be implemented. However, the Commission later determined that it did not have budgetary authority to conduct such a study and to date no supplemental EITE study has occurred.[205]

CARB's partial EITE sector analysis and CPUC's inability to conduct a supplement EITE sector analysis leaves the Commission only partially able to identify EITE industry – those that happen to operate in NAICS sectors where at least one CARB-covered facility existed in California prior to 2010. Relying on a partial determination of EITE is not sufficient or appropriate here. We also note that the primary factor here would be gas usage intensity, not emissions intensity, since the impacts here correspond to gas usage and not emissions quantities.

Additionally, Indicated Shippers points to the existence of the Industry Assistance Credit[206] to argue that "the electric utilities know exactly who EITE

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[203] D.12-12-033 at 84.

[204] D.12-12-033 at 86.

[205] D.14-12-037 at 9.

[206] The California Industry Assistance Credit stems from the electric utilities' revenues from consigning allowances allocated to them by CARB for sale in CARB's Cap-and-Invest Program auctions. This is the same funding source for the residential electric Climate Credits and Small Business Climate Credits. Industry Assistance credits are provided to eligible EITE customers of the electric IOUs.

customers are."[207] The implication is the existence of the Industry Assistance credit means an exemption for EITE non-core gas customers could be implemented directly and easily. We cannot conclude this is the case for multiple reasons. First, the Industry Assistance program is an electric customer credit. The electric utilities know who their *electric* EITE customers are. There is no similar program on the gas side; gas utility allowance revenues are returned entirely to residential gas customers and the gas utilities do not administer any credit program for other customer groups. We have no indication either that the gas utilities have any way of identifying these customers already, nor whether every electric EITE customer is also a gas EITE entity. The record of this proceeding does not focus on EITE issues and does not contain the detailed trade exposure data and other information necessary to establish an exemption. But this is a technical problem, and therefore it may have a technical solution.

Finally, we again note that a focus on minimizing emissions leakage risks while allocating RGS above-market costs to non-core customers would focus on non-core customers' gas *usage* intensity, not their *emissions* intensity. While Cap-and-Invest compliance costs stem from emissions obligations, costs here stem from gas usage. (In both cases, the concern is focused on emissions from that industry moving out of state.)

Given all these considerations, it is reasonable to require an additional process to support consideration of possible ways to implement the non-core allocation in a way that minimizes the risk of emissions leakage. We authorize the following process to address this issue.

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[207] Indicated Shippers Second Supplemental Comments at 5.

The utilities will initiate coordination with relevant stakeholders on a Biomethane Emissions-Intensive Industry Exemption Workshop process and subsequently file a joint application on these issues. This joint utility workshop process will seek input from state agencies including CARB and the Commission, gas utilities, non-core industrial customers and industry representatives, ratepayer advocates, and environmental and social justice groups. This input-gathering process should provide these stakeholders multiple opportunities (via multiple workshops and review opportunities) to provide input on the workshop process scope, deliverables, summary of the workshop process, and the draft application.

The workshop process shall address:

a. Whether additional non-core customers not currently designated as EITE face risk of emissions leakage and can or should be identified and included in an exemption to reduce that risk;

b. Whether impacts of RGS above-market costs on emissions leakage risk can be differentiated from that of other costs, and whether an exemption from some portion of RGS above-market costs allocated to these customers is necessary to avoid emissions leakage, and if so, to what extent;

c. Whether any exemption for EITE customers should be accompanied by any restrictions or requirements;

d. Whether non-core EITE customers can be identified and designated within utility billing systems, and if so, identify this list;

e. What the range of potential impacts of not granting such exemptions could be on increasing costs to Californians for essential goods such as food, gas, or manufactured products;

f. What the range of potential impacts of such exemptions on other customers would be; and

g. Whether any technical or regulatory changes or guidance are needed to effectuate exemptions.

Within 18 months of the first workshop in the Biomethane Emissions-Intensive Industry Exemption Workshop process, the joint gas utilities must file an application requesting Commission findings regarding 1) whether the non-core allocation of RGS above-market costs should be implemented; 2) whether an EITE and/or additional exemption should be implemented, and if so, the proposed implementation process. The application must describe the findings and conclusions of the workshop process and identify points of consensus and disagreement among stakeholders.

This process will allow stakeholders to gather information and provide input on possible exemptions and support future Commission consideration of including such exemptions when enacting the non-core allocation.

With respect to parties' arguments regarding impacts on electric generators, we do not find any reason to direct an exemption here. Impacts on these customers can be explored as part of the workshop process above. Additionally, it is not necessary at this time to direct such an exemption as any allocation to non-core customers will be determined at a later date via the application that will be filed following the workshop process described above.

We have already addressed the Joint Parties' argument that RGS program biomethane reduces the utility's compliance obligation without reducing the compliance obligation of covered entity non-core customers, finding this correct but equitable.

Finally, we note that SCGC's input and arguments regarding the reasonableness of RGS program costs are outside the scope of this proceeding.

This proceeding is addressing how to allocate authorized costs, not whether those costs should be or should have been authorized.

We decline at this time to direct an allocation to non-core customers. Any non-core exemption that may be directed will be determined at a later date via the application that will be filed following the workshop process described above.

7. Cost Allocation Methodology

The Scoping Memo asks, "What cost allocation methodology should be used? For example, should costs be allocated on an equal volumetric basis, such as ECPT, or using fixed and proportional volumetric rates?"[208]

There are two main methodologies discussed in the record: one that allots costs on an equal-cents-per-therm (ECPT) basis, and one that allots costs such that each customer class experiences the same percent increase: an equal percent change (EPC) basis.

7.1.1. Party Comments

Cal Advocates, the Gas IOUs, TURN, SBUA, and LJCA support the use of the ECPT methodology.[209] The Sempra Utilities address why they view this as the more appropriate methodology: "ECPT allows for allocated costs across the customer classes to be socialized more in alignment with the consumption of gas versus methodologies based on costs of gas service."[210] The Sempra Utilities also clarify that the fact that above-market costs reflect only the costs of achieving

[208] Scoping Memo Issue 4a.

[209] Joint Case Management Statement, Attachment B at 2.

[210] Exhibit SCG/SDGE-02 at RMS-MWF-4.

state policy and reducing emissions, not the commodity cost of serving bundled core, means the benefits should be allocated volumetrically and equally by all.[211]

PG&E recommends integrating the costs into existing transportation rates as the simplest and most easily-implemented way of collecting them; a separate charge is not necessary and its recommended approach could be implemented without any modifications to its billing system.[212] It proposes recording the costs in its subaccounts that already recover costs on an ECPT basis from respective classes.[213]

The Joint Parties oppose the ECPT approach, saying it would " impose on unbundled core and non-core customers a disproportionate burden of increases generated solely for bundled core procurement customers."[214] While noting their opposition to any allocation beyond bundled core, Joint Parties state that if we "deviate from sound regulatory policy," and take that approach, "a more equitable methodology of allocating costs than ECPT" is one based on achieving equal percentage change (EPC) across customer classes.[215] Joint Parties describe EPC as a way to "smooth out the cost increases across customer classes":

> "[U]sing numbers that are provided solely for illustration, an equal 10% increase on Commission regulated gas utility services would produce the following result: core customers would pay a 10% increase in their utility-provided gas procurement costs and a 10% increase in their gas transportation costs, for an overall 10% increase in Commission regulated services on their utility bill. Non-core customers would pay a 10% increase in gas transportation costs, for

[211] Exhibit SCG/SDGE-02 at RMS-MWF-4

[212] Exhibit PG&E-01 at 2-2 and 2-3.

[213] Exhibit PG&E-01 at 2-2 and 2-3.

[214] Exhibit Joint-01 at 12.

[215] Exhibit Joint-01 at 12.

an overall 10% increase in Commission regulated services on their utility bill.[216]

In rebuttal to Joint Parties' recommendation, PG&E asserts that "there is no basis to support EPC:

> "This would imply that the gas that non-core customers consume is less harmful to the environment per therm than core customers gas usage per therm. This is not true. Allocating ECPT ensures a fair and equitable distribution of the above-market biomethane procurement costs to all customers, and until all customers are mandated to procure biomethane gas, then all customers should pay for the above-market biomethane procurement costs."[217]

SCGC did not advance a specific methodology and stated that a study is required to support a conclusion about the appropriate distribution of environmental benefits.[218] As previously noted, SCGC opposes the ECPT approach, asserting that non-core customers do not experience so much more benefit from emissions reductions that they should pay the majority of the costs.[219] PG&E responds to this argument: "SCGC's flaw in analysis ignores the fact that 14 non-core customers use 62.1 percent of the gas. Therefore, it is a key point that it is the volume of gas used, not the number of customers, that negatively impacts the environment. Accordingly, an ECPT allocation ensures a fair and equitable distribution of the above-market costs thus also negating the need for a study as proposed by SCGC."[220]

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[216] Exhibit Joint-01 at 12.

[217] Exhibit PG&E-02 at 2-3.

[218] Exhibit SCGC-01 at 9.

[219] Exhibit SCGC-01 at 9.

[220] Exhibit PG&E-02 at 2-4.

7.1.2. Discussion

We agree with the utilities, Cal Advocates, and TURN that the ECPT methodology is appropriate and reasonable.

The EPC method put forward by Joint Parties achieves one result: it increases costs by the same percentage for each class. It is therefore unrelated to the nature of the cost; the only reason put forth by the Joint Parties in support of this methodology is essentially that it results in more costs being borne by bundled core than under any volumetric approach (since the non-core class uses more gas than core). This is a slim justification.

In contrast, the logic for the ECPT methodology is aligned with the type of cost being allocated: one where costs and benefits correspond to usage. As previously addressed, the above-market costs being allocated do not reflect the commodity cost of gas. They will first be reduced by any avoided costs; they therefore represent the net above-market costs of achieving a state emissions reduction goal.

We find that the most straightforward methodology that allocates net costs and benefits in alignment with the nature of these costs is the ECPT methodology. It is reasonable to allocate RGS above-market costs on an ECPT basis.

With respect to exact implementation in billing systems, we agree with PG&E. Because this decision orders the immediate allocation of costs to all core customers, it is not necessary or appropriate at this time to create a new nonbypassable charge to collect the costs, since that would extend costs to all gas utility customers. Including the costs in core procurement rates would also not be effective since only bundled core customers pay those rates. We also find no reason to direct the creation of a new billing component. The allocated costs can be included in core transportation rates, since those are the rates paid by all core customers and only core customers. It is reasonable to integrate RGS above-market costs into existing rate components. This decision directs the utilities to update their tariffs to incorporate RGS above-market costs into core transportation rates.

7.2. Special Considerations

This proceeding considers whether any customer groups should receive special considerations or exemptions from cost allocation. The Scoping Memo asks:

> "Should any customer groups receive special considerations or exemptions from cost allocation, including CARE customers, FERA customers, or customers in disadvantaged communities? If so, what adjustments should the Commission make to the cost allocation methodology for these customer groups?"[221]

Prior to the supplemental rulings, parties mainly discussed exemptions other than those for EITE. We have separately addressed EITE exemption issues in Section 6.

7.2.1. Party Comments

Cal Advocates and the Gas IOUs argued that CARE customers, if allocated costs, would benefit under existing program discounts.[222] All parties agreed to the conclusion that, at a minimum, CARE customers would receive their existing discount on such costs. Parties further agreed that FERA customers are not affected since FERA is an electric rate discount program, not one available to gas customers.[223]

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[221] Scoping Memo Issue 4c.

[222] Exhibit CA-01 at 3, Exhibit PG&E-01 at 2-2; Exhibit SCG/SDGE-01 at RMS-MWF-7; Exhibit SWG-1 at 6-7.

[223] Joint Case Management Statement, Attachment B.

LCJA requested exemption for all CARE and FERA customers, as well as customers that live in disadvantaged communities.[224] LCJA sees little value in the RGS program and thus it argues CARE customers will not receive benefits in exchange; LCJA does not support the extension of these costs to customers generally; and LCJA argues that this allocation will "exacerbate energy unaffordability" for CARE customers in particular.[225]

SCGC asserted that electric generators should be exempt from paying above-market costs of biomethane, noting a direct connection between higher gas costs and higher electricity prices.[226]

SBUA stated that CARE customers and small commercial customers who are disadvantaged, underserved, or face significant barriers to access should be excluded.[227]

PG&E, the Sempra Utilities, Southwest Gas, and Cal Advocates oppose all proposed exemptions, and argue that no additional discount or benefit beyond the existing discount should be extended to CARE customers, as part and parcel of their support for broader cost allocation.[228] As PG&E puts it, "[affordability] concerns are not unique to small business customers or non-core customers… If the Commission exempts certain customers from these costs, as SBUA proposes, then another customer group will have to absorb those costs."[229] With respect to SCGC's proposed exemption for electric generators, PG&E rejoins that such an

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[224] Joint Case Management Statement, Attachment B.

[225] LCJA Opening Brief at 6-7.

[226] Exhibit SCGC-01 at 9.

[227] SBUA Opening Brief at 11-19, Joint Case Management Statement, Attachment B.

[228] Joint Case Management Statement, Attachment B.

[229] PG&E Reply Brief at 18-19.

exemption would be out of alignment with decarbonization goals and that electric generator customers share in the benefits of the RGS program.

7.2.2. Discussion

We agree with parties that CARE customers will receive their existing discount under the adopted allocation.

We find little support for LCJA's assertion that CARE customers should be entirely exempt; this would not align with the nature of these costs. LCJA's proposals are grounded in its opposition to the RGS program and its total disagreement with the concept that "incentivizing biomethane is sound public policy"; its argument for exempting all CARE customers can be paraphrased as, *this cost should not be allocated to customers at all, but if it is, exempt CARE.*[230] R.13-02-008 extensively addressed whether the RGS program should be pursued; the instant proceeding must determine the fair and reasonable sharing of costs authorized there. LCJA does not provide, and the record does not contain, a sufficient justification for this exemption for CARE. We understand and appreciate LCJA's goal of reducing costs for low-income customers, but our job here is to identify the most reasonable allocation approach.

Similarly, SBUA's proposed exemptions for small businesses are not sufficiently supported. We agree with PG&E that "[a]ffordability concerns are not unique to small business customers or noncore customers,"[231] and given that no other justification is provided in the record (we also note that these proposals were raised for the first time in briefs), we do not approve such exemptions. Beyond that, we are concerned that such exemptions would entail significant

[230] LCJA Opening Brief at 6.

[231] PG&E Reply Briefs at 18.

implementation complexity, given that the utilities do not have existing billing structures defining or verifying "small business" whether low-income or in DACs.

Finally, as we addressed in Section 6.1.3 regarding non-core allocation issues, we also do not adopt an exemption for exempting electric generators.

We conclude that it is reasonable to not adopt exemptions for any subcategory of core customers. This decision does not adopt any exemptions from the adopted cost allocation structure. However, consistent with the discussion in Section 6 above no allocation will be applied to core customers at this time. Any allocation to core customers will be determined via a separate application as set forth above in Section 6.

8. Nonbypassable Charge Issues

Several issues in the Scoping Memo specifically relate to nonbypassable charges. Issue 6 asks: "Should the Commission establish a new nonbypassable charge for biomethane procurement?"[232] Issue 7 asks: "If the Commission establishes a new nonbypassable charge for biomethane procurement, by what regulatory authority could this program be created?"[233] Issue 8 asks: "If the Commission establishes a new nonbypassable charge for biomethane procurement, should IOUs maintain exclusive ownership of all environmental attributes from contracted biomethane sources as directed in D.22-02-025?"[234]

A nonbypassable charge is a charge that all utility customers must pay (no customer can "bypass" them). The cost allocation enacted in this decision does not at this time include all customers. Therefore, these issues are moot and we do

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[232] Scoping Memo Issue 6.

[233] Scoping Memo Issue 7.

[234] Scoping Memo Issue 8.

not address them. Furthermore, parties had noted[235] that Issue 8 overlapped with issues within the scope of R.13-02-008, and indeed, Issue 8 was rendered moot by D.26-04-044, which addressed ownership rules pertaining to RTCs.

9. Implementation Process

This section addresses the implementation processes required to enact and oversee the adopted cost allocation approach.

This decision directs the immediate allocation of RGS above-market costs to all core customers. RGS above-market costs include all authorized costs associated with the RGS program above the market cost of fossil gas. "Authorized" in this context means "authorized for collection from ratepayers." Above-market costs include, but are not limited to, commodity, transportation, and administrative costs. This does not currently include RTC marketing costs. Above-market costs will also reflect cost savings and avoided costs such as avoided Cap-and-Invest compliance costs. It will include cost savings from reduced transmission costs if these costs are quantified in the future.

As the utilities have noted, they expect to incur various costs, such as storage costs and pipeline capacity costs, directly associated with the RGS program. Because the utilities will need to account for associated costs and verify them, we direct them to file Tier 2 Cost Allocation advice letters proposing the specific process they will use and associated accounting details. Market costs will be calculated; total RGS program costs will be detailed, including avoided costs; market costs will be subtracted from total RGS program costs to arrive at RGS above-market costs; and such costs will be included in core transportation rates.

The Cost Allocation advice letters will provide the following elements:

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[235] LCJA 2026 Supplemental Comments at 2, PG&E 2026 Supplemental Comments at 2.

1. Proposed tariff changes to allocate costs to core customers within core transportation rates on an equal-cents-per-therm basis;
2. A proposed process and methodology to calculate the monthly market cost benchmark for the purposes of determining RGS program above-market costs. The market cost benchmark calculation will use average daily Citygate prices from that month from independent third-party sources for data for the utility's respective Citygate(s). The utilities shall specify the exact sources and monthly timing they will use.
3. A proposed process for using the market cost benchmark to determine RGS above-market costs: for each month in which they procure biomethane, the utilities will multiply the market cost benchmark by the biomethane quantity procured in that month to arrive at the RGS Cost Allocation market cost benchmark: the cost the utility would have paid to procure that amount of fossil gas on the market in that month. All authorized, associated RGS program costs incurred in that month that exceed the RGS Cost Allocation market cost benchmark will be considered RGS above-market costs and allocated pursuant to this decision.
4. A proposed methodology for calculating the avoided GHG compliance cost for above-market cost allocation purposes. The basic methodology shall reflect: GHG compliance costs per unit of emissions consistent with the utility's existing GHG cost forecasting processes, multiplied by the amount of emissions that would have been associated with the use of fossil gas and the amount of RGS biomethane procured.
5. A template for the account that will be included in the utility's cost recovery filings, including detail on all authorized, associated RGS program costs, clearly reflecting:
   i. The type of cost or avoided cost: storage, commodity (specifying the contract), distribution, avoided GHG

compliance costs, etc.; with clear differentiating details such as date and location incurred;

ii. A citation to the Commission order authorizing ratepayer recovery of each type of cost;

iii. Verification or attestation that the recorded cost is associated with the RGS program.

6. Any necessary changes to RGS program tariff definitions to reflect:

i. That RGS above-market costs are all authorized costs associated with the RGS program above the market cost of fossil gas;

ii. That market costs used for the purposes of RGS above-market cost allocation are the cost of fossil gas, to be calculated as described above for the market cost benchmark;

The utilities' proposed accounting processes above must support transparency and oversight of the allocated costs.

Separately, the utilities will each also file a RGS Program Associated Costs Tier 2 Advice Letter. This advice letter shall contain a complete list of the cost types associated with the program (as also required in 5(i) in the above list) that the utility has incurred or expects to incur within the next 180 days. The utilities file biomethane annual reports pursuant to D.16-06-029 in R.13-02-008 and shall also include the list of cost types associated with implementing the RGS program in these reports. These reporting measures will support staff and stakeholder awareness of the types of costs associated with the program on a prospective basis and separate from the Annual Gas True-Up filings.

10. Summary of Public Comment

Rule 1.18 of the Commission's Rules of Practice and Procedure allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

There are no public comments on the Docket Card for this proceeding.

11. Procedural Matters

Various motions for confidential treatment of information were filed by parties and were pending as of the issuance of the proposed decision. Attachment A lists these motions. No objections or opposition to these motions have since been filed by any party, and we find good cause to grant these motions. The requested confidentiality treatment shall be granted for a period of three years. At any point from six months from the date of this Decision to the conclusion of the three-year period of confidentiality, each moving party may move to seek a furtherance of the confidentiality treatment on the basis of whether additional good cause is shown.

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

12. Comments on Proposed Decision

The proposed decision of Commissioner Houck 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 __________, and reply comments were filed on _____________ by ________________.

13. Assignment of Proceeding

Darcie L. Houck is the assigned Commissioner and Maria Sotero is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Total Renewable Gas Standard (RGS) costs equal commodity costs and all other authorized costs associated with the program.
2. RGS above-market costs represent the incremental cost (above the market cost of fossil gas) of using biomethane procurement to reduce emissions from biological feedstock sources.
3. The market cost of fossil gas represents the cost that the utility would have otherwise incurred for gas.
4. Managing and distributing RGS biomethane will have associated costs.
5. Authorized, associated costs will be incurred during the operation of the program and will depend on a multitude of factors, such as the location, production quantity, and production timing of biomethane projects
6. There are existing authorization processes for storage, pipeline capacity, and pipeline infrastructure costs.
7. It is not possible to quantify in advance all costs associated with the RGS program.
8. The utilities will incur associated authorized costs other than just the commodity cost and transportation and distribution costs.
9. Above-market costs will also reflect cost savings and avoided costs, such as avoided Cap-and-Invest compliance costs as well as cost savings from reduced interstate transport if these costs are quantified in the future.
10. Avoided transmission costs of the RGS program cannot currently be defined in detail, differentiated from Citygate prices, or quantified in advance.
11. There is no clear, quantifiable method available for measuring avoided transmission costs and deducting them from total costs.

12. Renewable Thermal Credits (RTCs) are digital certificates that can be used to track and verify biomethane carbon intensity and compliance with biomethane procurement targets.

13. RTCs capture, at least in part, the value of RGS program environmental benefits for the purposes of cost allocation.

14. There is uncertainty about the current and future value of RTCs.

15. Existing measures can be used to reduce above-market costs.

16. There are two main ways RGS program environmental benefits can be partly quantified.

17. The use of fossil gas by utility customers creates a compliance obligation for the utility under California's Cap-and-Invest Program.

18. The emissions from the use of biomethane do not carry a compliance obligation under California Air Resources Board (CARB) regulations.

19. Because any RGS biomethane injected into California's pipelines would necessarily replace the equivalent volume of fossil gas, biomethane therefore avoids the GHG compliance cost that the utility would have otherwise incurred and passed to customers.

20. At least part of the environmental benefits of RGS biomethane can be quantified by calculating the avoided GHG compliance cost associated with the equivalent amount of fossil gas.

21. Under existing rules utilities are required to retain ownership of RTCs; they may not sell them, nor may they execute contracts that allow biomethane producers to retain them.

22. The Commission has authority to allocate procurement costs to bundled core customers.

23. The RGS program was not created because of core procurement need, but instead to reduce emissions.

24. The levels of the RGS program short-term targets were set based on organic waste volumes, not bundled core (or any class's) demand.

25. The Commission set the RGS program medium-term target at a level that would support Short-Lived Climate-Pollutant (SLCP) reduction goals.

26. The utilities' individual shares of the overall short-term target were set based on their proportionate Cap-and-Invest allowance allocations. Each utility's allocation is based on the level of emissions from all the utility's customers who are non-covered entities under Cap-and-Invest, not just those from bundled core customers.

27. RGS program targets will be adjusted based on factors other than procurement need or levels of demand from any customer class, because the RGS program was not established to meet those needs or sized based on them.

28. From the RGS program's inception, the Commission made clear that the program was being created to solve an emissions and biowaste problem and was not sized based on expected demand of any customer class.

29. RGS program benefits such as emissions reductions are not limited to the bundled core class.

30. No statute or code section specifically prohibits our allocation of RGS above-market costs pursuant to our general authority and discretion.

31. The Commission has the authority to allocate RGS above-market costs to all customers.

32. All customers drive and benefit from RGS program above-market costs.

33. Allocating RGS program above-market costs to all customers is in line with traditional cost causation and cost allocation principles.

34. RGS program above-market costs are not typical procurement costs that would be paid only by bundled core customers and instead they are the costs of meeting a state emissions reduction goal and should be allocated beyond the bundled core class.

35. Bundled core customers are currently the only customers paying RGS above-market costs.

36. Pub. Util. Code Section 651 does not require the Commission to consider allocating targets to Core Transport Agent (CTA) customers before allocating RGS above-market costs pursuant to our authority.

37. Allocating costs to CTAs is not in conflict with, and does not violate, AB 678.

38. Exempting CTAs could drive reductions in the number of customers remaining, increasing costs for those who remain.

39. The equal percent change (EPC) method put forward by Joint Parties achieves one result: it increases costs by the same percentage for each class. It is therefore unrelated to the nature of the cost.

40. The logic for the equal cents per therm (ECPT) methodology is aligned with the type of cost being allocated: one where costs and benefits correspond to usage.

41. CARE customers will receive their existing discount on costs allocated by this decision.

42. FERA customers are not affected by this decision since FERA is an electric rate discount program, not one available to gas customers.

43. CA Industry Assistance is an electric investor-owned utility customer credit program.

44. The Industry Assistance program relies on specific six-digit NAICS codes to calculate customer credit amounts. NAICS codes classify many different types of industries and are used by CARB as part of its Cap-and-Invest regulation to identify which electric customers qualify for assistance due to their Emission-Intensive and Trade-Exposed (EITE) nature.

45. If a facility is an electric IOU customer and operates in a qualifying six-digit NAICS code, it is considered EITE and receives an annual CA Industry Assistance credit.

46. Medium- and small-sized industry customers that operate in an industry that did not have at least one covered entity at the time CARB conducted its study were not evaluated by CARB and therefore will not appear on CARB's EITE NAICS list.

47. The Commission is only partially able to identify EITE industries – those that happen to operate in NAICS sectors where at least one CARB-covered facility existed in California prior to 2010.

48. Allocating RGS above-market costs to non-core customers entails some amount of emissions leakage risk.

Conclusions of Law

1. It is reasonable to use the cost of fossil gas as the market cost benchmark for the purposes of allocating total RGS above-market costs.

2. From total RGS costs, market costs should be subtracted and the remaining above-market costs should be allocated.

3. It is reasonable to define RGS above-market costs as all authorized costs associated with the RGS program above the market cost of fossil gas.

4. It is reasonable to use the most straightforward approach reflecting recent, average Citygate prices to arrive at the market cost benchmark of fossil gas.

5. It is not reasonable to define allocable costs as only including commodity, transportation, and distribution costs.

6. It is reasonable to define RGS above-market costs as "all authorized costs associated with the RGS program above the market cost of fossil gas."

7. RGS program benefits can be at least partly quantified, and quantified benefits should be shared with customers via a reduction of above-market costs.

8. It is reasonable to share the quantified avoided GHG compliance costs with customers who are paying RGS costs by subtracting that value from above-market costs before allocating them.

9. If in the future the utilities are authorized to monetize RTCs, any financial value of RTCs should be subtracted from the above-market costs of related RGS biomethane before its allocation to customers.

10. Ensuring that unbundled core customers share in RGS above-market costs is reasonable not only because of the nature of the costs themselves, but also because it provides protection to core customers.

11. It is reasonable to allocate RGS above-market costs to all customers because they are not core procurement costs and instead are the costs of meeting state emissions reductions and waste diversion goals.

12. It is not reasonable to charge non-core customers for an emissions reduction program in a way that directly results in emissions leakage.

13. It is reasonable to defer allocation of any RGS above market costs to core customers and require an additional process to consider possible ways to implement the non-core allocation in a way that reduces the risk of emissions leakage.

14. It is reasonable to allocate RGS above-market costs on an ECPT basis.

15. It is not necessary or reasonable at this time to create a new nonbypassable charge to collect above-market costs.

16. The allocated costs should be included in core transportation rates, since those are the rates paid by all core customers and only core customers.

17. It is reasonable to grant the motions for confidential treatment of information listed in Attachment A of this Decision.

18. It is reasonable to affirm all rulings made by the ALJ and the assigned Commissioner in this proceeding and to deem denied all motions not ruled on.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company, Pacific Gas and Electric Company, Southern California Gas Company, and Southwest Gas Corporation (the Gas IOUs) shall, within 30 days of the issuance of this decision, each file Tier 2 Renewable Gas Standard Cost Allocation Advice Letters implementing the allocation of the above-market costs of the Renewable Gas Standard program to all core customers on an equal-cents-per-therm basis within core transportation rates. The advice letters shall include:

   a. Proposed tariff changes to allocate costs to core customers within core transportation rates on an equal-cents-per-therm basis;

   b. A proposed process and methodology to calculate the monthly market cost benchmark for the purposes of determining RGS above-market costs. The market cost benchmark calculation will use average daily Citygate prices from that month from independent third-party sources for data for the utility's respective Citygate(s). The utilities shall specify the exact sources and monthly timing they will use;

   c. A proposed process for using the market cost benchmark to determine RGS above-market costs: for each month in which they procure biomethane, the utilities will multiply the market cost benchmark by the biomethane quantity procured in that month to arrive at the RGS Cost Allocation market cost benchmark: the cost the utility would have paid to procure that amount of fossil gas on the market in that month. All authorized, associated RGS program costs incurred in that month that exceed the RGS Cost Allocation market cost benchmark will be considered RGS above-market costs and allocated pursuant to this decision;

d. A proposed methodology for calculating the avoided GHG compliance cost for above-market cost allocation purposes. The basic methodology shall reflect: GHG compliance costs per unit of emissions consistent with the utility's existing GHG cost forecasting processes, multiplied by the amount of emissions that would have been associated with the use of fossil gas and the amount of RGS biomethane procured; and

e. Any necessary changes to RGS program tariff definitions to reflect that RGS above-market costs are all authorized costs associated with the RGS program above the market cost of fossil gas; and that market costs used for the purposes of RGS above-market cost allocation are defined as the cost of fossil gas as calculated for the RGS Cost Allocation market cost benchmark.

2. The Tier 2 Renewable Gas Standard Cost Allocation Advice Letters required under Ordering Paragraph 1 shall also include a template for the account that will be included in the utility's cost recovery filings, including detail on all authorized, associated RGS program costs, clearly reflecting:

a. The type of cost or avoided cost: storage, commodity (specifying the contract), distribution, avoided GHG compliance costs, etc.; with clear differentiating details such as date and location incurred;

b. A citation to the Commission order authorizing ratepayer recovery of each type of cost; and

c. Verification or attestation that the recorded cost is associated with the RGS program.

3. San Diego Gas & Electric Company, Pacific Gas and Electric Company, Southern California Gas Company, and Southwest Gas Corporation (the Gas IOUs) shall, within 60 days of the issuance of this decision, each file a Renewable Gas Standard Program Associated Costs Tier 2 Advice Letter. This advice letter shall contain a complete list of the cost types associated with the program that the utility has incurred or expects to incur. The Gas IOUs shall file additional Tier 2 advice letters to update this list as needed, and shall also include the list of associated cost types in their Biomethane annual reports required by D.15-06-029.

4. San Diego Gas & Electric Company, Pacific Gas and Electric Company, Southern California Gas Company, and Southwest Gas Corporation shall, within 60 days of the issuance of this decision, provide a joint notice to the service list of this proceeding and the service list for R.13-02-008 of the date of the first workshop in the Biomethane Emissions-Intensive Industry Cost Allocation/Exemption Workshop process. The first workshop in this process shall occur within 120 days of the issuance of this decision. The workshop process will seek input from state agencies including CARB and the Commission, gas utilities, non-core industrial customers and industry representatives, ratepayer advocates/representatives, and environmental and social justice groups. This input-gathering process should provide these stakeholders multiple opportunities (via multiple workshops and draft review opportunities) to provide input on the workshop process scope, deliverables, summary of the workshop process, and the draft application. The workshop process shall address: whether non-core emissions-intensive trade-exposed (EITE) customers can be identified and designated within utility billing systems,

and if so, identify this list; whether additional non-core customers not currently designated as EITE face risk of emissions leakage and can or should be identified and included in an exemption to reduce that risk; whether impacts of RGS above-market costs on emissions leakage risk can be differentiated from that of other costs, and whether an exemption from the RGS above-market costs allocated to these customers is necessary to avoid emissions leakage, and if so, to what extent and whether it would be a whole or partial exemption; whether any exemption for EITE customers should be accompanied by any restrictions or requirements; what the range of potential impacts of such exemptions on other customers would be; and whether any technical or regulatory changes or guidance are needed to effectuate exemptions.

5. Within 18 months of the date of the first workshop in the Biomethane Emissions-Intensive Industry Cost Allocation/Exemption Workshop process, San Diego Gas & Electric Company, Pacific Gas and Electric Company, Southern California Gas Company, and Southwest Gas Corporation shall jointly file an application requesting Commission findings regarding 1) whether the non-core allocation of RGS above-market costs should be implemented; 2) whether an emissions-intensive trade-exposed (EITE) exemption should be implemented, and if so, the proposed implementation process. The application must describe the findings and conclusions of the workshop process and identify points of consensus and disagreement among stakeholders. The application shall request a Commission finding regarding whether the allocation of RGS above-market costs to non-core customers should be implemented with an exemption (either in whole or partial) for EITE customers.

6. The motions for confidential treatment of information that are listed in Attachment A of this Decision are granted. This information shall remain under

seal for a period of three years after the date of this decision, except pursuant to a further order or ruling of the Commission or an Administrative Law Judge. If any entity believes that it is necessary for any of this information to remain sealed for longer than three years, the entity may file a new motion at least 30 days before the expiration of the three-year period, stating the justification for further withholding the information from public inspection.

7. All rulings made by the assigned Administrative Law Judge and the assigned Commissioner in this proceeding are affirmed and all motions not ruled on are deemed denied.

8. Rulemaking 22-12-011 is closed.

This order is effective today.

Dated _____, at Sacramento, California.

ATTACHMENT A

Motions for Confidential Treatment Granted by this Decision

Party	Date of Motion	Description of Motion
Pacific Gas and Electric Company	June 12, 2025	Motion for leave to file under seal confidential responses to CTA Ruling
San Diego Gas & Electric Company, Southern California Gas Company	June 12, 2025	Motion for leave to file under seal confidential responses to CTA Ruling
Small Business Utility Advocates	September 27, 2024	Motion for leave to file under seal confidential opening brief
Agricultural Energy Consumers Association, California Manufacturers & Technology Association, Indicated Shippers, California League of Food Producers	September 26, 2024	Motion for leave to file under seal confidential opening brief
San Diego Gas & Electric Company, Southern California Gas Company	September 12, 2024	Motion for leave to file under seal updated confidential procurement cost data
Pacific Gas and Electric Company	June 28, 2024	Motion for leave to file under seal confidential procurement cost data
San Diego Gas & Electric Company, Southern California Gas Company	June 28, 2024	Motion for leave to file under seal confidential procurement cost data
Southwest Gas Corporation	June 28, 2024	Motion for leave to file under seal confidential procurement cost data

(End of Attachment A)