COM/JR5/asf **PROPOSED DECISION** **Agenda ID #24081 (Rev. 1)**
**Quasi-Legislative**
**4/9/2026 Item #28**

Decision **PROPOSED DECISION OF COMMISSIONER J. REYNOLDS (Mailed 3/6/2026)**

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

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| Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions. | Rulemaking 13-02-008 |

# DECISION IMPLEMENTING CHANGES TO THE RENEWABLE GAS STANDARD PROGRAM AND MODIFYING RENEWABLE GAS PROCUREMENT PLANS

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# DECISION IMPLEMENTING CHANGES TO THE RENEWABLE GAS STANDARD PROGRAM AND MODIFYING RENEWABLE GAS PROCUREMENT PLANS

## Summary

Today's decision addresses many of the outstanding issues within the Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions. Of note, this decision: (1) adopts a Cost Containment Mechanism to protect ratepayers from extreme rate impacts; (2) reduces the overall procurement target set in Decision 22-02-025 from 72.8 billion cubic feet annually to 36.4 billion cubic feet annually; (3) extends both the Diverted Organic Waste procurement target and the overall procurement target to 2035;[1] (4) allows all feedstocks to bid into future Utility solicitations; (5) requires all procurement contracts to be submitted via Tier 2 Advice Letter regardless of contract price; and (6) orders modifications to the gas utilities' draft Renewable Gas Procurement Plans. Collectively, these modifications aim to create a more streamlined Renewable Gas Standard program while protecting ratepayers from excessive above market costs.

This proceeding remains open to address a Petition for Modification of Decision 22-12-057.

## 1. Proceeding Background

Rulemaking (R.) 13-02-008 was initiated on February 13, 2013 to implement the various provisions of Assembly Bill (AB) 1900 (Gatto, Chapter 602, Statutes 2012). AB 1900 added several code sections pertaining to biogas and biomethane. More specifically, AB 1900 added California Health and Safety Code Section 25421,

[1] D.22-02-025 created a "short-term" and "medium-term" target. This decision modifies this structure to create an overall 2035 target of 36.4 Bcf, with a diverted organic waste (DOW)-specific 2035 target of 17.6.

which established the process that the California Public Utilities Commission (Commission) and its partner government agencies must follow in order to ensure that any biomethane injected into the common carrier pipeline system is safe.[2] The AB 1900 process ultimately requires the Commission to "adopt pipeline access rules that ensure that each gas corporation provides nondiscriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the delivery of gas."[3] Aside from safety considerations, AB 1900 also requires the Commission to "adopt policies and programs that promote the in-state production and distribution of biomethane."[4]

Following the initiation of R.13-02-008, a prehearing conference was noticed and held on March 27, 2013. An initial scoping memo and ruling (Scoping Ruling) was issued on May 2, 2013. The Scoping Ruling set forth the scope of issues to be addressed in this proceeding.

Since the issuance of the May 2013 Scoping Ruling, there have been four additional Scoping Rulings or Amended Scoping Rulings. Each iteration of the Scoping Ruling has provided direction for this proceeding, and this decision addresses the issues remaining from Phase 4 of this rulemaking.

## 2. Phase 4 of R.13-02-008 Background

On November 21, 2019, the Commission initiated Phase 4 of R.13-02-008 to implement Senate Bill (SB) 1440 (Hueso, Chapter 739, Statutes 2018), which

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[2] Subdivision (c) of that code section requires the Commission to adopt, on or before December 31, 2013, "standards that specify, for constituents that may be found in that biomethane, concentrations that are reasonably necessary to ensure" the protection of human health, and pipeline and pipeline facility integrity and safety. In addition, to "ensure pipeline and pipeline facility integrity and safety," subdivision (d) of Health and Safety Code § 25421 requires the Commission to "adopt the monitoring, testing, reporting, and recordkeeping requirements identified pursuant to paragraph (5) of subdivision (a)" of that code section.

[3] California Public Utilities (Pub. Util.) Code Section 784.

[4] Pub. Util. Code Section 399.24.

requires the Commission to consider adopting biomethane procurement targets or goals for each investor-owned utility (IOU) providing gas service in California.[5] The assigned Commissioner's Scoping Ruling initiating Phase 4 of this proceeding (Phase 4 Scoping Ruling) identified three specific action items necessary to implement SB 1440: (1) consultation with the California Air Resources Board (CARB), (2) a determination as to whether biomethane procurement targets or goals can be adopted in a cost-effective manner while complying with all applicable state and federal laws, and (3) consideration of seven specific issues necessary to ensure compliance with Pub. Util. Code Section 651(b). On June 5, 2020, the assigned Commissioner issued a subsequent Amendment to the Phase 4 Scoping Ruling and added seven additional issues for consideration in Phase 4 of this proceeding.

On June 3, 2021, the assigned Administrative Law Judge (ALJ) issued a ruling (Biomethane Procurement Ruling) directing parties to comment on an Energy Division staff proposal (Staff Proposal). A copy of the Staff Proposal was attached to the Biomethane Procurement Ruling, and it recommended establishment of a biomethane procurement program for California's four large gas utilities: San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas) (*jointly,* Sempra), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (SWG) (*collectively*, the Utilities). The Biomethane Procurement Ruling directed parties to file comments on four specific questions related to the Staff Proposal and any other relevant issues that were not addressed in the Staff Proposal.

On February 24, 2022, the Commission issued Decision (D.) 22-02-025, the decision Implementing SB 1440 Biomethane Procurement Program. The decision

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[5] San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas) (together, Sempra Utilities), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (SWG) (*collectively*, the Utilities).

directed the adoption of a Renewable Gas Standard (RGS) program to initiate biomethane procurement by the Utilities.

On April 5–6, 2022, in compliance with Ordering Paragraph (OP) 1 of D.22-02-025, a workshop was held concerning the Standard Biomethane Procurement Methodology (SBPM) and the Renewable Gas Procurement Plans (RGPPs). On July 5, 2022, each of the Utilities respectively submitted proposed a single uniform SBPM through Advice Letters 4626-G, 6003-G, 3098-G, and 1222-G. These Advice Letters were approved on December 28, 2022.

On December 28, 2022, pursuant to OP 31 of D.22-02-025, the Utilities submitted draft RGPPs. These draft RGPPs have not yet been approved. Pursuant to the same OP, the Commission shall issue a proposed decision "providing specific instructions to each of the utilities for what to modify or include in their final RGPP." On July 20, 2023, an ALJ Ruling ordered responses regarding RGS program cost estimate data. On August 21, 2023, these RGS program cost estimate data responses were filed by the Utilities, with confidential information filed under seal.

On May 1, 2024, the Utilities filed a Joint Biomethane Annual report. On June 10, 2024 the Assigned Commissioner issued a Ruling (ACR) seeking comments on the RGS Program and Issues outstanding from D.22-02-025 (June 10, 2024 ACR). As the ruling noted, "RGS procurement solicitations have been moving forward in accordance with D.22-02-025, OP 28, and these solicitations have brought to light issues concerning the development of this nascent market. In addition, due to the regulatory landscape's complexities and evolution, the RGS program may require modifications." Comments on the June 10, 2024 ACR were filed on July 23, 2024 and August 16, 2024, respectively.[6]

[6] Citations including "Comments" without specifying a particular ruling refer to party comments on the June 10, 2024 ACR.

After reviewing the information submitted, Commission Staff identified a gap in understanding the interconnection costs. Accordingly, the Assigned Commissioner issued a Ruling[7] ordering the Utilities to respond to a list of questions regarding interconnection costs. The Assigned Commissioner's Ruling Ordering Responses to Interconnection Cost Questions (Interconnection Cost ACR) was issued on September 23, 2025. Parties filed responses on October 23, 2025 and November 3, 2025, respectively.

## 3. Submission Date

This matter was submitted on November 3, 2025, with the filing of Reply Comments on the Interconnection Cost ACR.

## 4. Jurisdiction

SB 1440 requires the Commission, in consultation with CARB, to consider adopting specific biomethane procurement targets or goals for each gas corporation. Pursuant to Pub. Util. Code Section 650, "biomethane" means methane produced from an organic waste feedstock that meets the standards pursuant to subdivisions (c) and (d) of Section 25421 of the California Health and Safety Code for injection into a common carrier pipeline. Pursuant to Pub. Util. Code Section 651, the targets or goals adopted by the Commission must be cost-effective means of achieving the forecast reduction in the emissions of short-lived climate pollutants (SLCPs).[8]

SB 1383 (Lara, Chapter 395, Statutes 2016) was established to reduce SLCPs by diverting organic waste from landfills to prevent climate emissions. SB 1383 requires strategies to reduce emissions of SLCPs to achieve a reduction in methane by 40 percent, hydrofluorocarbon gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030, as specified. The bill further

[7] *See* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M581/K198/581198756.PDF.

[8] Pub. Util. Code Section 651(a)(1).

requires the adoption of regulations that achieve the specified targets for reducing organic waste in landfills.

## 5. Issues Before the Commission

This decision resolves the issues identified in the Phase 4 Scoping Ruling, the June 10, 2024 ACR and the Interconnection Cost ACR. Additionally, it orders modifications to the Utilities' pending RGPPs.

Specific to the Phase 4 Scoping Ruling, many of these issues are addressed in D.22-02-025. However, as the June 10, 2024 ACR noted, there are some aspects of the RGS Program that warrant revisiting based on market conditions. Phase 4 of this proceeding includes the following issues: (1) what are the appropriate biomethane procurement targets for each gas corporation; (2) could procurement targets be met by any renewable gas that complies with applicable pipeline injection standards; (3) the recommendations developed pursuant to Health and Safety Code Section 39730.8 (Pub Util. Code Section 651(b)(1)); (4) are the targets or goals consistent with waste disposal requirements of Health and Safety Code Section 39730.6 and regulations pursuant to Public Resources Code Section 42652.5 (Pub. Util. Code Section 651(b)(2)); (5) how to determine if the biomethane procurement meets the requirements set forth in Pub. Util. Code Section 651(b)(3)(B)(i); (6) how to demonstrate the biomethane procurement meets at least one of the requirements of Pub. Util. Code Section 651(b)(3)(B)(ii); (7) how will the Utilities recover the costs of meeting procurement targets? What is the expected impact on rates; (8) whether to base procurement target on greenhouse gas (GHG) emission reductions achieved, rather than gas volume, or adopt other provisions to ensure that GHG reductions are maximized; (9) which biomethane sources have the greatest short-lived climate pollutant reduction benefit; (10) how to ensure there are environmental benefits from the procurement that accrue to the utility and/or its customers, and are not used or claimed by another entity; (11) what fuel certification and verification measures are appropriate; (12) what are reasonable estimates of the supply of biomethane available to meet a procurement target as well as meet other demands, including for alternative vehicle fuels; (13) how can we ensure that the procurement will not frustrate or conflict with efforts to decarbonize buildings through electrification; and (14) how can we ensure that the impact of meeting procurement targets on rates paid by customers is reasonable.

In the June 10, 2024 ACR, parties were asked to weigh-in on the structure of the RGS Program adopted in D.22-02-025. Issues addressed in the June 10, 2024 ACR include the following: (1) procurement alignment with SB 1383; (2) contract timelines; (3) subsidizing interconnection costs; (4) revisiting Advice Letter tiers; (5) cost caps; (6) third-party verification; (7) off-site facility natural gas combustion; (8) SBPM modifications; (9) RGS out-of-state procurement considerations; (10); encouraging RGS market participation; (11) Midwest Renewable Energy Tracking System (M-RETS) alternatives; (12) tracking and forecasting RGS procurement; (13) linking RGS procurement and the Voluntary Renewable Natural Gas Tariff (VRNGT) program; (14) RGS procurement landfill eligibility requirements; (15) regulatory barriers; (16) equitable pipeline capacity access; and (17) incorporating avoided carbon dioxide equivalent (CO2e) value as an RGS program metric.

While the majority of issues above are addressed in this decision, a few issues cannot be addressed at this time and could ultimately need to be addressed in a future proceeding. Deferred issues include those related to pipeline capacity access, encouraging RGS market participation, regulatory barriers, and the VRNGT program.

## 6. Discussion and Analysis

This decision makes significant changes to the RGS program, including a reduction in procurement volume and an extension of the procurement timeline.

These changes stem from a need to avoid excessive ratepayer burden in the face of a new program and a nascent market that is still evolving.

Under the procurement framework established by D.22-02-025, the Utilities' customers[9] would bear a disproportionate share of the state's SB 1383 SLCP mitigation costs. Yet, according to CARB's 2023 GHG inventory, residential and commercial gas customers are responsible for only 2.6 percent of statewide methane emissions,[10] and the CARB Scoping Plan envisions biomethane procurement as a means to primarily decarbonize hard-to-electrify end uses, including industrial processes.[11] It is not reasonable to expect ratepayers to bear such significant above market costs, so this decision takes steps to protect ratepayers from excessive above market RGS costs, by establishing a Cost Containment Mechanism (CCM), reducing the overall RGS procurement target by 50%, and extending that target 5 years, to 2035.

These changes chart a new trajectory for the RGS program, protecting customer affordability while advancing the state's core policy goal of SLCP emissions mitigation. The RGS will be a source of stable, long-term financing for biomethane projects in California that are advancing the state's SB 1383 policy goals, especially its diverted organic waste (DOW) goals. While we reduce the overall RGS procurement target by 50%, the DOW target remains at 17.6 billion cubic feet (Bcf), sustaining D.22-02-025's goal of supporting SB 1383's waste

[9] Per the Staff Proposal that preceded the adoption of D.22-02-025, "Residential and small commercial customers are called "core" customers and large commercial, industrial, cogeneration, and utility electric generation customers are called "noncore" customers." Additional discussion regarding the difference is customer types can be found in the Staff Proposal in Section 2.1.

[10] According to CARB's 2023 Greenhouse Gas Emissions Inventory, 2023 methane emissions of residential and commercial gas customers was 0.97 MMTCO2e out of the statewide total of 36.74. See "CH4 Only" Data Categorized by Economic Sector at https://ww2.arb.ca.gov/ghg-inventory-data.

[11] CARB 2022 Scoping Plan at 1-2. See: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

diversion goals. To further support the DOW procurement target, we require biomethane sourced from all types of co-digestion to separate its component feedstocks for attribution purposes rather than count all co-digestion as DOW.

We also allow non-DOW feedstocks, including open landfills, to bid into future Utility solicitations. Non-DOW feedstocks are important, both for the state's broader SB 1383 goals and also for ratepayer interests, as allowing non-DOW feedstocks into Utility solicitations can promote competition and drive down overall contract costs. All feedstocks will be evaluated on the ratepayer impact (via the CCM), on the $ per ton of CO2e avoided emissions, and the other factors considered in the SBPM, though Utilities will still bear responsibility for meeting the DOW-specific procurement target.

This decision takes the following steps to protect ratepayers while still driving forward the state's SB 1383 SLCP emissions reductions goals:

1. Institutes strict rate caps to contain ratepayer costs, limiting average annual rate impacts to 1 percent over a rolling 15 year period with a maximum growth of 3 percent in any given year within that period.
2. Reduces and extends the medium-term procurement target previously adopted in D.22-02-025 by half and extends the compliance timeline by five years, thus shifting the procurement target from 72.8 Bcf annually by 2030 to 36.4 Bcf annually by 2035.
3. Requires biomethane sourced from all types of co-digestion to separate its component feedstocks for attribution purposes rather than count all co-digestion as DOW.
4. Promotes competition by allowing all feedstocks to bid into IOU RGS solicitations, while retaining SB 1383's focus on DOW.
5. Eliminates D.22-02-025's tiered Advice Letter structure in favor of universal Tier 2 Advice Letter oversight.

6. Directs the Utilities to modify their RGPPs in accordance with this decision as Tier 2 Advice Letters pursuant to the direction provided in OP 31 of D.22-02-025.
7. Eliminates the 2040 program end date to allow procurement contracts to extend beyond 2040.
8. Authorizes procurement of brown gas biomethane without accompanying environmental attributes.
9. Directs the Utilities to submit a Tier 3 Advice Letter proposing approaches to separately market avoided methane emission attributes..
10. Directs the Utilities to submit a Tier 2 Advice Letter that addresses how to avoid perverse incentives that could result in increased organic waste intake at RGS-participating open landfills and any other requirements for open landfill participation in the RGS, including safety requirements.
11. Directs the Utilities to submit a Tier 2 Advice Letter outlining a proposal to reduce interconnection costs and promote competition. The Utilities may submit an Application requesting ratebasing of interconnection costs for RGS projects based on the approved interconnection cost reduction plan..

### 6.1. Cost Caps

The July 20, 2023 ALJ Ruling directed the Utilities to file responses regarding biomethane procurement cost estimates and program cost caps. On August 21 and 22, 2023, the Utilities individually and confidentially filed responses as ordered, and these confidential responses are available to this proceeding's nonmarket participant parties who are RGS solicitation Procurement Advisory Group (PAG) members. The Utilities' proposed cost caps vary widely. Accordingly, the June 10, 2024 ACR asked parties to respond to: (1) should the Commission consider a single consistent cost cap for all Utilities or should the Utilities be able to use different cost caps; and (2) if a single cost cap were to be applied to all Utilities, which of the proposed cost caps should be adopted?

The Coalition for Renewable Natural Gas (CRNG) supports the creation of price-containment mechanisms (price ceilings and floors) in markets for biomethane, stating that, when set appropriately, these features can increase investor certainty in such markets and provide consumer protection.[12] CRNG notes that an RGS price cap could be imposed so that utilities do not procure biomethane above a specified amount.[13] For example, this price cap could be set at a $/ton level conceptually in line with prior discussions of cost-effectiveness in the decision, and potentially even aligned with, price caps in other California programs.[14] CRNG provides as an example that the Low Carbon Fuel Standard (LCFS) has a price cap set at $253.53/metric ton carbon dioxide equivalent in 2023 (and is indexed to inflation).[15]

The Bioenergy Association of California (BAC) recommends that the Commission not set a hard cost cap at this point and, instead, do what the Commission did in D.14-12-081 for the BioMAT program.[16] In D.14-12-081, the Commission established a price point which, if reached, required the Commission to undertake a mandatory program review to see if the price was justified and if other changes to the program were needed.[17]

Sierra Club comments there does not appear to be a legitimate basis for using different cost caps among utilities.[18] Sierra Club notes that to the extent bidders can ascertain the cost caps used by each utility, differing cost caps could result in higher

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[12] CRNG Opening Comments at 14.

[13] CRNG Opening Comments at 14.

[14] CRNG Opening Comments at 14.

[15] CRNG Opening Comments at 14, referencing https://ww2.arb.ca.gov/resources/documents/lcfs-credit-clearance-market.

[16] BAC Opening Comments at 12.

[17] BAC Opening Comments at 12, referencing D.14-12-081 at 62-63.

[18] Sierra Club Opening Comments at 18.

cost procurement as bidders focus offers on utility RFOs with the highest cost caps.[19]

Sempra comments that the Commission should allow the California gas utilities to use their individually developed price caps filed in the instant proceeding.[20] SoCalGas cost caps were developed using two primary components, above market cost and revenue requirement, both of which are unique and representative of SoCalGas's operations and ratemaking structure.[21] As such, Sempra believes that a single cost cap structure for all gas Utilities would not consider variation in IOU revenue requirement, costs related to regional market development, infrastructure differences, and/or procurement practices.[22]

SWG cautions that establishing and applying a uniform cost cap as it may create a price signal to the market. SWG supports the Utilities being able to set cost caps reflective of their specific circumstances including, customer base, service territory, and market access to biomethane supplies which are highly variable between the Utilities.[23] The utility notes that California is the third largest state with diverse economic and climate considerations that vary across each Utility's service territory.[24] As a result, a cost cap that may be appropriate for one utility's service territory could simultaneously be burdensome and unfeasible for another, and consequently limit broader program viability.[25]

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[19] Sierra Club Opening Comments at 18.

[20] Sempra Opening Comments at 8.

[21] Sempra Opening Comments at 8.

[22] Sempra Opening Comments at 8.

[23] SWG Opening Comments at A-7.

[24] SWG Opening Comments at A-7.

[25] SWG Opening Comments at A-7.

California Bioenergy (CalBio) suggests that cost caps should only be considered after some minimal volume has been contracted over several years.[26] This will allow the true cost of biomethane procurement to be discovered as scale increases. If procurement costs do not decrease as expected with scale, price caps could be considered.

PG&E notes that each utility is unique and should have a unique cost containment mechanism reflective of their business plan and strategy.[27] PG&E encourages the Commission to approve the cost cap that PG&E proposed as part of its RGPP.[28] PG&E notes that if a single cost cap were applied to all utilities, PG&E's cost containment mechanism should be adopted because it was used as a foundation for other gas utilities' cost containment mechanisms.[29]

Shell Energy North America, L.P. (Shell) doesn't support cost caps prior to market development and procurement. Shell notes cost caps are counterproductive and create significant barriers to market development. Shell supports each contract being evaluated individually based on just and reasonableness requirements, with the Commission retaining the ability to reject contracts with excessive costs.

Weighing the arguments above, we understand the concerns on establishing a cost cap across the Utilities. Moreover, we understand the concern on what a cost cap may signal to the still nascent biomethane market. However, the need to protect ratepayers from excessive above market costs overrides these considerations. Accordingly, we implement an RGS Cost Containment Mechanism (CCM) based on

[26] CalBio Opening Comments at 3.

[27] PG&E Opening Comments at 8.

[28] *See* PG&E's draft RGPP available at Microsoft Word - R.13-02-008_PGE RGPP Compliance Filing 12-28-22 FINAL.docx.

[29] PG&E Opening Comments at 8.

PG&E's proposal as described in Section E of its draft RGPP, and modified by Sempra's proposal in comments on the proposed decision.[30]

The CCM operates as follows. The CCM establishes, for each Utility, two independent tests that must be satisfied before the Commission will approve new RGS procurement: 1 percent Program Cost Cap and a 3 percent Annual Increase Cap. The CCM is the controlling constraint on biomethane procurement, and the Commission will not approve new procurement that would cause a Utility to fail either test.

For each of the four Utilities, the above market cost (AMC) of a given RGS contract is calculated as the difference between the contract's total price and the prevailing forward price for both natural gas at the applicable delivery point (e.g., the SoCal Citygate for Sempra, PG&E Citygate for PG&E, or a comparable index for SWG), less the avoided cost value of any Cap-and-Invest (C&I) attribute associated with the biogenic gas. This per-unit premium — reflecting the above-market cost paid specifically for climate benefits — is multiplied by the contract's expected annual delivery volumes to yield the forecasted annual above market cost for that contract.[31] Annual above market costs are aggregated across all active RGS contracts in the Utility's portfolio to determine the total portfolio AMC by year.

The CCM tests are applied at the time of contract submission. The calculation window for each test begins with Program Year 1, defined as 2022 consistent with the effective date of D. 22-02-025, and extends through the final delivery year of the proposed contract. AMC for previous Program Years should be recorded portfolio

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[30] Sempra Comments on Proposed Decision at Appendix C.

[31] To estimate delivery volumes, Advice Letters seeking approvement of RGS contracts should include low, medium, and high delivery volume estimates, and a narrative description of each scenario and their rough likelihood, and an estimate of expected delivery volumes by year.

above-market costs. For future Program Years, AMC should reflect the sum of forecasted AMC across all active contracts and the proposed contract.

The 1 percent Program Cost Cap is calculated as follows: for each program Year *n* in the calculation window, the Utility shall compute the running average of AMC from Program Year 1 through year *n*. This running average is then expressed as a percentage of the RGCAP revenue requirement for that same year *n*. If this running average exceeds 1 percent of RGCAP in any Program Year within the calculation window, the CCM fails the Program Cost Cap and the Commission will not approve the proposed procurement.

The 3 percent Annual Increase Cap is calculated as followed: for each Program Year, the Utility shall compute the year-over-year change in above-market costs as a percentage of the prior year's customer revenue requirement plus above-market costs. If this figure exceeds 3 percent in any year within the calculation window, the CCM fails the Annual Increase Cap test and the Commission will not approve the proposed procurement, regardless of the result of the Program Cost Cap test.

For customer revenue requirement, we are persuaded by Sempra to use the Renewable Gas Cost Allocation Pool (RGCAP) framework.[32] The RGCAP revenue requirement is initially defined as the Non-Natural Gas Vehicle Bundled Core Customers (NBCC) revenue requirement; however, we note that the Commission is currently considering cost allocation issues in R.21-12-011, and may adjust which customer classes are allocated costs.

[32] Sempra Opening Comments, Appendix C.

Because the methodology for calculating market-index prices, allocating above market costs to rate classes, and computing revenue requirement impacts involves utility-specific ratemaking structures, the Commission directs the utilities to jointly propose a standardized rate impact calculation template, which Utilities shall file with any Advice Letter seeking RGS procurement approval. The Utilities must coordinate with the Commission's Energy Division to develop and implement this standardized template. The Utilities shall jointly submit a Tier 1 Advice Letter to the Commission's Energy Division to implement this standardized reporting template within six months of issuance of this decision. We also grant PG&E's request to propose future CCM modifications via Tier 2 AL,[33] so long as those changes do not change the stated caps or undermine the core principles of the CCM as explained above in and the Conclusions of Law.

### 6.2. Procurement Targets

In D.22-02-025, the Commission adopted a short-term procurement target of 17.6 Bcf of biomethane annually, produced from eight million tons of organic waste, including wood waste diverted from landfills.[34] This short-term target uses the conversion from the California Department of Resources Recycling and Recovery (CalRecycle) Senate Bill 1383 rule, California Title 14 of California Code of Regulations (CCR) Section 18993.1(g)(1)(C).[35] This direction was in support of 14 CCR Section 18993.1(a), which requires jurisdictions to procure a quantity of recovered organic waste products to create market pull for the diversion of organic wastes required in SB 1383. D.22-02-025 specified that beginning in 2025, the Commission would review the medium-term target in the current or a successor

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[33] PG&E Opening Comments on Proposed Decision at 9.

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

[35] D.22-02-025 at OP 14.

proceeding, 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[36]

The June 10, 2024 ACR asked parties a series of questions regarding SB 1383 procurement alignment. The ACR acknowledges that due to feedstock limitations, ratepayer costs for biomethane produced from DOW could be high due to lack of solicitation competition in the short-term as SB 1383 continues to ramp up. As the ruling recognizes, a path forward may be to modify and relax D.22-02-025 requirements for the short-term (2025) procurement target, to mirror D.22-02-025 requirements for the medium-term (2030) procurement target. This could be accomplished through maintaining prioritization of SB 1383-derived biomethane through modifications to the SBPM. Such a path forward would allow a broader range of entities to bid into the Utilities' procurement solicitations, potentially increasing biomethane available for procurement, increasing competition, and reducing ratepayer costs.

Additionally, the June 10, 2024 ACR asked for comments on the definition of SB 1383-derived biomethane feedstocks. Defining the eligible "SB 1383-derived" feedstocks as adhering to 14 CCR Sections 18982(a)(46), 18982(a)(62), 18983.1(b), and 18993.1-18993.4, as verified by a third-party independent verification body accredited by CARB, could ensure that all biomethane receiving this prioritization is in fact an output of SB 1383 activities. While D.22-02-025 does not expressly adopt this definition (despite indicating its intended alignment with SB 1383), referencing these CCR sections may clarify what is meant by eligible feedstocks.[37]

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[36] D.22-02-025 at OP 19.

[37] June 10, 2024 ACR at 5.

Most party comments suggest that the short-term targets cannot be met with the current procurement restrictions, considering delays in SB 1383 implementation as of 2025. Some parties also voice concerns that biomethane from feedstocks other than DOW provide questionable value to ratepayers or even cause environmental damage. Suggested solutions include expanding feedstock eligibility for the short-term target, delaying targets with and without changes to feedstock eligibility, reducing target volumes, and even eliminating the short- or medium-term targets. We discuss some specific recommendations below.

CRNG, BAC, Waga Energy, Inc. (Waga), Marvel Power Group (Marvel), Agricultural Energy Consumers Association (AECA), Anew RNG (Anew), PG&E, Sempra, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates), SWG, Shell, and Electrochaea Corporation (Electrochaea) all support relaxing short-term procurement requirements to mirror medium-term procurement requirements, which would allow procurement of all feedstocks before meeting the 8 million ton short-term organic waste diversion target.

CRNG states that, due to delays in SB 1383 implementation, "… local jurisdictions have not yet succeeded in diverting anything close to this magnitude of organic material from landfills"[38] and "… reaching the short-term target for biomethane procurement set forth in D.22-02-025 by next year will not be possible under the current procurement restrictions… While continued focus on achieving California organic waste diversion goals is needed, it should not delay utility procurement of RNG from strong GHG-reducing RNG projects using other feedstocks/technologies."[39]

[38] CRNG Opening Comments at 3.

[39] CRNG Opening Comments at 4.

BAC agrees that diversion of organic landfill waste is behind schedule, but should begin ramping up in the near term.[40] Rather than moving the short-term procurement target all the way to 2030, BAC urges the Commission to set an interim target in 2027 or 2028 and to maintain the 2030 procurement target since 2030 is the deadline for the over-arching methane and black carbon reduction requirements of SB 1383.[41] More specifically, BAC supports removing preference for biomethane from DOW, and, instead, adopt a CI-based approach for biomethane procurement that includes all organic waste sources whose capture or conversion to biomethane reduces SLCP emissions in California, as required by SB 1440.[42] BAC believes third-party verification and CARB accreditation is unnecessary to ensure compliance with SB 1383.[43] Adding CARB accreditation and/or third-party verification requirements would only add expenses and delays to the RGS and should not be necessary when local jurisdictions must already ensure that procurement products meet the requirements of CalRecycle's regulations.[44]

Waga strongly believes short-term target procurement restrictions must be relaxed to mirror medium-term target procurement requirements.[45] California jurisdictions have lagged in implementing diversion programs and there is not enough feedstock to support such landfill-diverted organics facilities.[46] Making landfill gas (LFG) to Renewable Natural Gas (RNG) projects eligible under SB 1440 would have a significant impact on the short-term RNG production available for

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[40] BAC Opening Comments at 5.

[41] BAC Opening Comments at 5.

[42] BAC Opening Comments at 5.

[43] BAC Opening Comments at 5.

[44] BAC Opening Comments at 5 to 6.

[45] Waga Opening Comments at 4.

[46] Waga Opening Comments at 4.

procurement, and these facilities require less time and money to become operational.[47] Waga also supports focus on driving cost reductions by allowing all feedstocks to be eligible to participate in the RGS Program.[48]

Marvel agrees that the short-term procurement target should be relaxed to align with medium-term procurement requirements.[49] Marvel provides, "the short-term procurement target of 17.6 Bcf of biomethane produced from organic waste diverted from landfills by 2025 represents a volume that is ~3.5x greater than the total nameplate capacity of all source-separated organics biomethane production in the entire U.S. The challenge is compounded by the fact that SB 1383 implementation has been significantly delayed…"[50] making "…the short-term procurement target, in its current form,…impossible to achieve."[51] Marvel provides that the medium-term procurement target be relaxed to grant the Utilities…additional time to identify/contract the needed volumes…"[52] because the "…the medium-term target volume of 72.8 Bcf represents >80 percent of total nameplate capacity of all biomethane production in the U.S. There is simply not enough supply to meet the near and medium-term requirements."[53]

AECA states "anticipated biomethane feedstocks are simply not currently available in quantities needed to support the RGS program's short-term procurement goals, due in part to delays in implementation of landfill diversion

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[47] Waga Opening Comments at 4.

[48] Waga Opening Comments at 4.

[49] Marvel Opening Comments at 3.

[50] Marvel Opening Comments at 3.

[51] Marvel Opening Comments at 3.

[52] Marvel Opening Comments at 3.

[53] Marvel Opening Comments at 3.

requirements.[54] The resulting limited feedstock supply will cause ratepayer costs to increase.[55] AECA strongly supports relaxing the short-term target procurement restrictions to mirror the medium-target requirements, to allow participation by an important segment of biomethane production – dairy projects.[56] The dairy sector in California accounts for roughly 45 percent of all human-caused methane production in the state."[57] Allowing dairy projects to qualify for biomethane procurement will offset the procurement shortfalls associated with delays in organic waste diversion, increasing competition, and reducing ratepayer costs by augmenting supply.[58]

Anew states that "the short-term target procurement restrictions should be relaxed to mirror the medium-term target procurement requirements… additional feedstocks should be allowed to compete for the fulfillment of the ambitious short-term targets… Organic waste diversion infrastructure (and the construction of projects to process biogas from the waste streams) has lagged behind the targets set out in SB 1383 for reasons that are outside of the control of the Utilities and the biomethane industry… allowing all feedstock types to be eligible through both 1440 program periods allows utilities to optimize their portfolios and achieve the maximum available GHG reductions from renewable gas procurement."[59]

PG&E believes that the Commission should eliminate the short-term target altogether in order to allow the RNG market to fully mature, thereby making procurement more affordable and achievable.[60] PG&E states that there has been

[54] AECA Opening Comments at 3.

[55] AECA Opening Comments at 3.

[56] AECA Opening Comments at 3.

[57] AECA Opening Comments at 3.

[58] AECA Opening Comments at 3 to 4.

[59] AECA Opening Comments at 3 to 4.

[60] PG&E Opening Comments at 2-3.

limited availability of DOW projects to procure in their solicitations, largely due to SB 1383 implementation delays.[61] The utility notes, until the local jurisdictions are fully compliant with the State's organic diversion goals established in SB 1383, PG&E believes it will be difficult to meet the short-term/diverted organic sourced RNG procurement targets established in D.22-02-025.[62] PG&E suggests that if procurement restrictions are relaxed, the SBPM could include a "qualitative preference in the qualitative section (Part B) of the Standard Biomethane Procurement Methodology (SPBM)."[63] The RGS procurement should not prioritize DOW feedstock if the RNG from projects utilizing such feedstock is more expensive.[64] As for third-party verification, PG&E proposes an executive officer attestation certifying that the feedstock is DOW and is "SB 1383-derived."[65] However, this proposal will not be needed if the short-term target and specific DOW targets are removed.[66]

Sempra comments that restrictions should be relaxed to allow for open procurement to meet both short-term and medium-term targets.[67] Sempra comments that the existing SBPM already inherently prioritizes landfill diversion feedstocks due to its consideration of CI. Also, any artificial price inflation would disqualify the project because of the SBPM's focus on price. "SB 1383-derived biomethane"[68] should be defined as both directly and indirectly supporting SB 1383

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[61] PG&E Opening Comments at 2-3.

[62] PG&E Opening Comments at 2-3.

[63] PG&E Opening Comments at 2-3.

[64] PG&E Opening Comments at 2-3.

[65] PG&E Opening Comments at 2-3.

[66] PG&E Opening Comments at 2-3.

[67] Sempra Opening Comments at 2.

[68] Sempra Opening Comments at 2.

landfill diversion, and no additional requirements should be added to the program because it may disincentivize participation and create uncertainty.[69]

Cal Advocates provides that due to current limitations to the CalRecycle supply of biomethane feedstocks, the Commission should take action to prevent inflated biomethane costs from being borne by ratepayers.[70] Cal Advocates recommends the Commission amend the short-term procurement requirements to reflect the medium-term requirements to allow more potential procurement solicitations and lower ratepayer costs.[71] Cal Advocates also recommends a verification process that would be paid for by the biomethane producer. Cal Advocates comments, "if the utilities are prioritizing SB 1383-derived biomethane as a cost-effectiveness criterion, it stands to reason that SB 1383-derived biomethane would be more valuable and higher priced than SB 1383-ineligible biomethane. It is therefore fair and reasonable to adhere to the existing stated California Code of Regulations (CCR) definitions, to use independent verification, and to require biomethane producers, instead of ratepayers, to bear the cost of verification."[72]

SWG supports relaxing short-term target procurement restrictions to mirror medium-term target procurement while stating that this may not result in lower costs.[73] SWG provides that the utility has already made efforts to achieve the short-term targets through a competitive request for proposal (RFP) process with limited success due to its geographic footprint and access to biomethane facilities.[74]

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[69] Sempra Opening Comments at 2.

[70] Cal Advocates Opening Comments at 1.

[71] Cal Advocates Opening Comments at 1.

[72] Cal Advocates Opening Comments at 2.

[73] SWG Opening Comments at A-1.

[74] SWG Opening Comments at A-1.

Currently, SWG's procurement target is approximately 0.286 Bcf biomethane per year through the end of 2025.[75] SWG believes more flexible procurement standards like the option to procure from eligible dairy facilities could potentially provide increased access to biomethane at an earlier date for SWG.[76] This is because some newly available feedstocks that could be used to meet the short-term target, such as dairy biomethane, may be more expensive than DOW.[77] However, the availability of these feedstocks would likely provide greater access to biomethane at an earlier date. SWG comments that any prioritization of SB 1383-derived feedstocks is unlikely to cause artificial price inflation because the volumes in question are "… a small portion of the overall Renewable Fuel Standard (RFS) and Low Carbon Fuel Standard (LCFS)."[78] SWG supports adherence to the relevant CCR, but finds the definition of renewable gas in 14 CCR Section 18982(a)(62) to be too restrictive if short-term procurement requirements are aligned with those of the medium-term.[79] SWG suggests utilizing the Environmental Protection Agency (EPA) verification process for biomethane should be used instead of 14 CCR Sections 18993.1-18993.4 contending it is accepted as the industry standard.[80]

Shell supports an approach that relaxes current restrictions on both short-term and medium-term targets, and urges the Commission to adopt a more resource-neutral framework for RGS participation.[81] Shell comments that because the feedstock that was intended to be procured through the short-term target is

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[75] SWG Opening Comments at A-1.

[76] SWG Opening Comments at A-1.

[77] SWG Opening Comments at A-1.

[78] SWG Opening Comments at A-1.

[79] SWG Opening Comments at A-2.

[80] SWG Opening Comments at A-2.

[81] Shell Opening Comments at 2 to 3.

unavailable, this restriction should be removed. Removing this restriction will "allow a broader range of entities to bid into Utility procurement solicitations," increasing the biomethane available for procurement, increasing competition, and reducing ratepayer costs.[82] Shell notes that this same reasoning applies to the medium-term target; the Commission needs to ensure there is sufficient biomethane that meets the procurement requirements to allow for utilities to timely and cost-effectively meet their procurement targets.[83] Shell additionally supports removing the restrictions on dairy biomethane procurement and removing the limitation on landfill gas procurement to facilities [84]that stop accepting new organic waste. Given the challenges in ensuring an adequate supply of biomethane to meet program targets, Shell supports including dairy biomethane as an option to meet medium-term target procurement, as dairy digesters provide the single most cost-effective option of all carbon reduction program.[85]

Electrochaea supports relaxing the short-term restrictions to match medium-term procurement requirements, while also reducing procurement restrictions on the medium-term, such as for dairy biomethane. Electrochaea suggests defining SB 1383-derived biomethane as being derived from biomass, with renewable gas defined as anything with a CI less than fossil natural gas, regardless of method of production.

Sierra Club opposes expansion of short-term procurement eligibility and instead recommends reducing the targets to avoid procuring "methane from other more costly sources such as biomass gasification and large dairies that have opted

[82] Shell Opening Comments at 2 to 3.

[83] Shell Opening Comments at 2 to 3.

[84] Shell Opening Comments at 3 to 4.

[85] Shell Opening Comments at 4.

to manage their manure in a way that creates methane"[86] or "opening up biomethane procurement to costly sources with dubious greenhouse gas ("GHG") benefits, such as methane manufactured from biomass."[87] Sierra Club also suggests that this would contribute to the "elimination of critical air quality, environmental justice, and environmental integrity safeguards"[88] and treating "ratepayers as a piggybank to de-risk private capital for the biomethane industry, even where it fails to align with California's climate, air quality and equity objectives."[89] Sierra Club goes on to say that allowing biomass gasification is premature because "no finalized methodology for determining whether creation of methane from biomass reduces SLCPs and other GHGs…"[90] and that a "credible life-cycle analysis methodology that has been peer reviewed and vetted by stakeholders and the Commission…"[91] is needed. Sierra Club also says that costs will likely increase by allowing procurement of biomethane from a wide range of feedstocks. Sierra Club also supports the additional verification requirements to prove biomethane is SB 1383-derived, rather than from organic material deposited in landfills.

Anaergia Services, LLC (Anaergia) notes that the RGS program should remain focused on DOW because SB 1440 "makes clear that the over-arching priority of the program is to help meet the SLCP reduction requirements of SB 1383 (Lara, 2016)."[92] Anaergia says that one of the primary reasons for delays in SB 1383 implementation is the lack of digestion infrastructure, so "maintaining current

[86] Sierra Club Opening Comments at 5.

[87] Sierra Club Opening Comments at 2.

[88] Sierra Club Opening Comments at 5.

[89] Sierra Club Opening Comments at 5.

[90] Sierra Club Opening Comments at 6.

[91] Sierra Club Opening Comments at 4.

[92] Anaergia Opening Comments at 3.

procurement targets [is] important to stimulate market growth and create an ecosystem for the next generation of digestion infrastructure to be built."[93] They go on to say that "Price inflation will be controlled by market competitiveness and public bidding processes."[94] Anaergia says that although feedstocks should adhere to the CalRecycle definition of organic waste, "third-party verification and CARB accreditation should ***not*** be necessary to ensure compliance with SB 1383."[95] This would just "add administrative, cost, and complexity."[96]

The Leadership Counsel for Justice and Accountability (LCJA) does not support relaxing of procurement requirements to match those of the medium-term because it would allow dairy biomethane procurement. LCJA instead suggests it would be "a more appropriate response would be to reduce or remove the procurement target"[97] because incentivizing dairy procurement would incentivize entrenching and expanding "harm in dairy-adjacent communities."[98]

After reviewing the market concerns about meeting the short-term and medium-term procurement targets, the Commission makes some adjustments to the procurement goals established in D.22-02-025. The targets should be feasible, and, most importantly, cost effective for ratepayers. Given the real procurement challenges the Utilities have pointed to, this decision also adjusts which feedstocks qualify for biomethane procurement. First, in recognition of party comments that DOW feedstock have been slow to materialize, and that RGS program procurement is far below targets, the Commission will allow the Utilities to procure from all

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[93] Anaergia Opening Comments at 5.

[94] Anaergia Opening Comments at 5.

[95] Anaergia Opening Comments at 5.

[96] Anaergia Opening Comments at 5.

[97] LCJA Opening Comments at 3.

[98] LCJA Opening Comments at 3.

feedstocks immediately without first meeting the short-term DOW procurement target implemented in D.22-02-025.[99]

Recognizing party concerns regarding the feasibility of current RGS target timelines, this decision also modifies the procurement targets, extending both procurement targets to 2035. This slows utility procurement to allow for market development and protects ratepayers from front-loaded procurement costs. Because the two procurement targets will now have the same deadline, we will refer to the two procurement targets as the "DOW target" and the "overall target," rather than the "short-term target" and "medium-term target."

This decision additionally reduces the overall target procurement volume target from 72.8 Bcf annually to 36.4 Bcf, or half of the medium-term target previously adopted in D.22-02-025. The DOW target remains unchanged (i.e., 17.6 Bcf annually). This change will have the effect of reducing the amount of non-DOW biomethane ratepayers will purchase through the RGS program, while ensuring the program retains its focus on DOW, as envisioned by SB 1383. To further bolster the RGS program's focus on DOW, this decision requires biomethane sourced from all types of co-digestion – including co-digestion without wastewater – to separate its component feedstocks for attribution purposes rather than count all co-digestion as DOW. This approach recognizes party comments, like those of the CRNG, that mention the need for continued focus on organic waste diversion goals.[100]

This decision does not alter the four percent livestock biomethane procurement limit established in OP 19 of D.22-02-025. Thus, the four percent livestock procurement limit applies to the new target discussed below.. The Commission has not seen any compelling evidence suggesting that the RGS program

[99] D.22-02-025 at OP 14.

[100] CRNG Opening Comments at 4.

would lead to the establishment of new dairies or expanded herds for the purpose of biomethane production. However, the Commission believes the procurement of biomethane from livestock sources has the potential to offer local pollution benefits, especially to disadvantaged communities, and, consistent with OP 9 of D.22-02-025, any dairy biomethane facilities under RGS contract must not cause adverse impacts to water and air quality.

The structure of the RGS program thus shifts from two deadlines to a single 2035 deadline, with an overall target for procurement (36.4 Bcf annually) and a DOW target (17.6 Bcf annually). Biomethane derived from DOW will count toward both the DOW target and the overall target, but biomethane derived from other non-DOW sources will only count towards the overall target.

### 6.3. Contract Timelines

The June 10, 2024 ACR asked parties to comment on RGS program contract length, flexibility, and structure in relation to the short- and medium-term targets. As directed by OP 56 of D.22-02-025, RGS program solicitation contracts are limited to 15 years, as biomethane delivery pursuant to the RGS program is not to extend beyond 2040. Therefore, to enter a 15-year contract ahead of that 2040 deadline, all activities necessary to supply the biomethane would have needed to have concluded by the end of 2025. Alternatively, the Utilities would have to enter into shorter contracts as the 2040 deadline approaches, which could push contract costs higher.

CRNG supports eliminating or modifying deadline language to allow contracts to continue to be signed even if the final year of the contract term is past 2040.[101] CRNG recommends allowing the maximum term of contracts be expanded to allow for 20-year contracts.[102] Allowing capital costs to be spread over an

[101] CRNG Opening Comments at 8.

[102] CRNG Opening Comments at 8.

additional five years is one way to achieve price reduction on a dollar-per-unit-energy basis and many components of well-built RNG facilities can reach a 20- year lifetime.[103]

BAC states that given the long lead time for biomethane procurement projects, having the 2040 deadline is a barrier that should be removed.[104] BAC comments that all projections, including the 2022 Climate Change Scoping Plan, assume continued gas use after 2040.[105] BAC comments that having a 2040 deadline will result in shorter and shorter contracts that prevent the market growth needed to see prices go down.[106] BAC notes shorter contract timelines will likely drive down program participation and make it harder to decarbonize remaining gas use by residential and small business customers.[107]

Cal Advocates does not support extension or elimination of the 15-year contract term. Given the current uncertainty surrounding biomethane supply and price volatility, Cal Advocates contends it is not in ratepayers' interest to allow long-term contracts based on current pricing if the Commission and parties expect biomethane to be less expensive in a matter of years. Cal Advocates supports the conclusion reached in D.22-02-025, that procurement contracts of a maximum of 15 years duration with deliveries not exceeding 2040 is "a reasonable limit that provides flexibility while also providing security in the form of long-term contracts."[108]

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[103] CRNG Opening Comments at 8.

[104] BAC Opening Comments at 6.

[105] BAC Opening Comments at 6.

[106] BAC Opening Comments at 6.

[107] BAC Opening Comments at 6.

[108] Cal Advocates Opening Comments at 3; D.22-02-025 at 50.

Anaergia states that costs will come down over time as the biomethane industry scales, which is critical for SLCP reductions. There needs to be actionable and predictable procurement to drive the market towards scale and lower costs, which includes swift approval of the first round of offtakes to incentivize more market participation. Anaergia supports elimination of the 2040 limit, as the 2022 Climate Change Scoping Plan assumes continued gas usage beyond 2040, as well as allowing 20-year contracts. Anaergia believes that core customer gas demand in California will never exceed the targets established in D.22-02-025.

Waga supports extending the deadline so that projects can complete a full 15-year contract.[109] Waga recommends allowing the maximum term of contracts be expanded to allow for 20-year contracts.[110] Most California projects include a 20-year interconnect agreement with utilities, with possibilities for extension.[111] Waga notes that if offtake agreements are shorter than the interconnect agreement, it may harm project viability and project financing.[112]

Shell comments that allowing for longer-term contracts will provide better certainty for facilities and developers, ultimately resulting in lower procurement costs.[113] At a minimum, the Commission should eliminate the 2040 deadline to allow for contracts to fulfill a full 15-year period of biomethane delivery.[114] Shell recommends that the Commission extend the maximum contract term to allow for

[109] Waga Opening Comments at 7.

[110] Waga Opening Comments at 7.

[111] Waga Opening Comments at 7.

[112] Waga Opening Comments at 7.

[113] Shell Opening Comments at 5.

[114] Shell Opening Comments at 5.

20-year contracts; noting that longer terms will both attract additional investment in biomethane production facilities and lower costs for ratepayers.[115]

PG&E supports elimination of the 2040 deadline, and recommends that only the 15-year contract term limit should apply to allow for more flexibility in contracted biomethane under this program.[116] PG&E provides, that as facilities require a number of years to design, permit, and construct, limiting the contracts to 2040 restricts the term of the contracts and the number of years that the RNG developer could recover its capital costs, and therefore leads to higher per unit RNG prices in the near term.[117]

Sempra supports the elimination of the 2040 contract deadline so as to allow fulfilling 15 years of biomethane delivery.[118] Sempra comments that 15-year contract terms are optimal for securing cost competitive contracts and provide adequate guardrails for length of delivery.[119] The 15-year term limit provides the appropriate control for procurement and allows for the most cost-effective contracts.[120] Sempra's experience has shown capitalization for new projects typically depend on an off-take agreement of up to 15 years to promote competition in pricing.[121] Sempra notes that a reduction in term increases the risks to the project, which adds to price inflation. To be financially viable, most projects that will be financed and built with short-term offtake agreements might require pricing that is comparable to the revenue streams that are available in the Renewable

[115] Shell Opening Comments at 5.

[116] PG&E Opening Comments at 4.

[117] PG&E Opening Comments at 4.

[118] Sempra Opening Comments at 3.

[119] Sempra Opening Comments at 3.

[120] Sempra Opening Comments at 3.

[121] Sempra Opening Comments at 3.

Identification Numbers (RINs) and LCFS markets; this pricing is higher than the pricing desired for SB 1440 offtake agreements.[122]

On review, the Commission agrees that cost reductions over time in the biomethane market are unclear, but that barring contracts beyond 2040 could drive costs higher. Furthermore, because this decision extends procurement targets to 2035, and implements a Cost Containment Mechanism that will further spread out procurement, procurement may go well into the 2030s. Accordingly, a removal of the 2040 contract limitation is necessary. This decision modifies OP 56 of D.22-02-025 to allow for deliveries that extend beyond 2040.

### 6.4. Midwest Renewable Energy Tracking System (M-RETS) Alternatives

As the June 10, 2024 ACR noted, the SBPM includes direction for producers to track volumetric injections of biomethane via the Midwest Renewable Energy Tracking System (M-RETS).[123] D.22-02-025 directed the Utilities to "require biomethane producers to track volumetric injections of biomethane into pipelines through the [M-RETS] platform and/or another platform identified in the SBPM workshop,"[124] thereby inviting possible M-RETS alternatives. In their December 28, 2022 draft RGPPs, the Utilities confirmed that they would require the use of M-RETS for tracking purposes to meet the D.22-02-025 requirements. However, in its August 21, 2023, response to the July 20, 2023 ALJ Ruling requesting program cost estimates and program modification recommendations from the Utilities, PG&E recommended the "creation of a lower-cost alternative to retiring renewable thermal certificates (RTCs) or tracking the environmental credits associated with biomethane."

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[122] Sempra Opening Comments at 3.

[123] SBPM at 3, submitted in Advice Letters 4626-G, 6003-G, 3098-G, and 1222-G.

[124] D.22-02-025 at OP 10.

The Commission may consider alternatives to M-RETS that can satisfy RGS procurement data tracking needs. M-RETS is used to "track and verify biomethane production, providing protections against the double-counting of biomethane environmental attributes, and facilitating transparency of the process for regulators," and creates attribution required for the registration of Renewable Thermal Certificates (RTCs), among other data reporting and verification activities. Any alternative selected by one or all of the Utilities would have to provide similarly robust and transparent verification services.

M-RETS comments that at this time there are no other reasonable alternatives for RGS procurement verification and tracking in the market.[125] Furthermore, any attempt to develop, implement, maintain, and market such a system would cost far more than using the existing M-RETS Platform.[126]

Sempra argues there are no alternative options to M-RETS.[127] PG&E believes the current pricing structure offered by M-RETS is unreasonable and will contribute to affordability issues for the program.[128] PG&E notes that if it were to meet its medium-term target starting in 2030, the utility anticipates paying over $2 million a year under the current M-RETS pricing structure for Renewable Thermal Certificate (RTC) tracking.[129] PG&E offers, should the gas utilities be unable to work out a better pricing structure for the program with M-RETS, a California state agency should hold a competitive solicitation among private and non-profit entities to provide this tracking service to the gas utilities.[130]

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[125] M-RETS Opening Comments at 4.

[126] M-RETS Opening Comments at 4.

[127] SoCalGas Opening Comments at 13.

[128] PG&E Opening Comments at 13.

[129] PG&E Opening Comments at 13.

[130] PG&E Opening Comments at 13.

Sierra Club disagrees with PG&E that multiple attribute trackers should be encouraged rather than use of single entity such as M-RETs.[131] Sierra Club contends that CRNG and other parties have acknowledged that the lack of a centralized database for attributed tracking is a major problem that must be solved to prevent double counting of attributes, as well as fraud.[132] Sierra Club believes that allowing multiple tracking systems is not the answer and will undermine program integrity.[133]

Given the technical nature of this tracking system, and the current state of biomethane procurement in California, we decline to adopt a different tracking system. The Utilities should continue to utilize M-RETS for purposes of biomethane procurement/projects.

### 6.5. Contract Structure and Renewable Thermal Certificate (RTC) Unbundling

D.22-02-025 established the RGS program with all environmental attributes transferred to the Utilities bundled and retired.[134] The June 10, 2024 ACR asked parties to comment on the possibility of marketing some or all of those RTCs to reduce costs to ratepayers. Some parties supported the option while others suggested continuing with the existing structure to allow benefits to be retired within the RGS program. Other parties requested additional flexibility in contracting to allow biomethane producers to keep the RTCs for themselves in some situations at a much lower contracted cost. There was also a question of whether all RTCs would be made available for marketing due to possible conflicts with the value

[131] Sierra Club Reply Comments at 21.

[132] Sierra Club Reply Comments at 21.

[133] Sierra Club Reply Comments at 21.

[134] "Environmental attributes" refers to the full bundle of attributes associated with each unit of procured biomethane as represented by a Renewable Thermal Certificate in M-RETS, including any embedded CI values.

associated with avoided Cap-and-Invest Regulation compliance costs from biomethane procurement.

CRNG supports allowing producers to keep some or all RTCs, although this could create added program complexity.[135] This would be comparable to how Renewable Energy Credits (RECs) are treated for solar.[136]

BAC suggests that separation of the physical gas and the RTCs should be avoided because it could lead to a more complex system. BAC notes that this separation would "undermine the requirement of SB 1440 that biomethane procurement provides a cost-effective means of reducing SLCP and GHG emissions… Separating the gas from other environmental attributes would also make it hard or impossible to know whether the biomethane in fact is providing the benefits to California's environment that are required by SB 1440. This should, at most, be an interim solution – and only for carbon emissions – while the Commission revises the RGS to be a CI-based program."[137] BAC also mentions that although they support switching to a strictly CI-based program, producers should be allowing to sell RTCs themselves instead of transferring them to the Utilities. This would encourage more carbon capture, use, and storage (CCUS), as well.[138]

CalBio recommends allowing RTCs to stay with the producers.[139] They state that generic RTCs with no CI could be procured for this type of biomethane separated from the RTC.[140] They say that this would reduce administrative

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[135] CRNG Opening Comments at 31.

[136] CRNG Opening Comments at 31.

[137] BAC Opening Comments at 21.

[138] BAC Reply Comments at 4.

[139] CalBio Opening Comments at 5.

[140] CalBio Opening Comments at 5.

complexity by not requiring the Utilities to conduct monitoring and verification.[141] They then state that ”Nothing in SB 1440 requires gas utilities to purchase all environmental attributes”[142] and that ” the utilities should only be required to purchase the attributes of the fuel that make it a renewable resource.”[143]

Sierra Club opposes recognition of negative carbon intensities from avoided methane emissions, stating that the baseline should be full regulation of methane emissions in California.[144] Sierra Club additionally expresses concern that the trading of RTCs could result in double counting.[145]

Anaergia expresses concern that separating the RTC from the physical gas is possible, but could add complexity to the program and add a premium to procurement of the brown molecule for ratepayers. They do support allowing biomethane producers to keep the value of the RTC if the program is not converted into a CI-based program, which they believe would be the best program structure.[146] They suggest that “The best and right solution is to make the offtake pricing appropriate.”[147]

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[141] CalBio Opening Comments at 5.

[142] CalBio Opening Comments at 22.

[143] CalBio Opening Comments at 23.

[144] Sierra Club Opening Comments at 31.

[145] Sierra Club Reply Comments at 20.

[146] Anaergia Opening Comments at 17-19.

[147] Anaergia Opening Comments at 18.

Waga points out that bundling the physical gas and the RTC together ensures that the value stay in California. If they are separated, the RTC could be transferred to places outside of the state.[148]

AECA supports keeping RTCs with the biomethane producer exclusively to allow them to be monetized in the dairy supply chain. Otherwise, biomethane producers are missing out on a significant value stream and ratepayers are overly burdened by the procurement cost.[149]

Anew suggests avoiding overcomplication by simply focusing on volumetric and CI targets. They suggest that the Commission should allow "the average procurement price cap to be sufficiently high to attract low-CI gas" and allow stacking of incentives from multiple programs, such as the LCFS.[150]

PG&E suggests converting the environmental attribute procured by the Utilities to an RTC representing 1 Dth of zero net emissions biomethane, as defined by a CI of no less than 0. This would allow biomethane producers to market any additional carbon intensities they may have available, allowing California Utilities to compete with other markets and buyers while still maintaining affordability. This supports their suggestion to focusing on volumetric procurement and allowing carbon credit markets to monetize the gas.[151] PG&E also responds to concerns that marketing of RTCs could lead to benefits being transferred to other states by saying

[148] Waga Opening Comments at 23.

[149] AECA Opening Comments at 11.

[150] Anew Opening Comments at 14.

[151] PG&E Opening Comments at 20-21.

that the benefits to California are still provided because eligible projects must prove environmental emissions and air, water, and land benefits to California.[152]

Sempra states that although there is no existing system that provides complete valuation of carbon intensities at present, managing a portfolio of biomethane RTCs would allow price discovery for a more complete valuation of these RTCs over time. Sempra notes there may be circumstances where it could be beneficial for the Utilities to procure only the physical gas for a portion or entirety of the contract. Flexibility in this could allow the Utilities to meet their program objectives in the most cost-effective manner.[153]

Cal Advocates states that, because the Cap-and-Invest Regulation does not differentiate between biomethane with high and low CI, CARB could issue free Cap-and-Invest Regulation allowances to biomethane producers to credit their negative carbon intensities that could then be marketed. Cal Advocates states that separation of the environmental attribute from the physical gas could create difficulties in preventing double-counting, and that a tracking system similar to that used for RECs in the RPS would be necessary.[154] Cal Advocates supports the RGS incentivizing lower CI biomethane to the greatest extent possible and the use of M-RETS to track compliance with the RGS.[155]

SWG supports allowing the separation of the physical gas and the RTCs. The added flexibility would allow them to procure biomethane interconnected with other distribution systems within California. The developers keeping the RTCs could also allow for more projects to be realized, supporting organic waste diversion

[152] PG&E Reply Comments at 22.

[153] Sempra Opening Comments at 18 to 19.

[154] Cal Advocates Opening Comments at 16.

[155] Cal Advocates Reply Comments at 11.

goals. They point out that the system would need to be developed carefully to avoid double counting.[156]

Dairy Cares points out that there are no legal requirements in Pub. Util. Code Section 651 that the Utilities retain the RTCs. They state that allowing producers to market RTCs could reduce procurement costs and encourage greater participation and competition within solicitations.[157] Dairy Cares mentions that double counting needs to be avoided by focusing on verifying RTCs in systems such as M-RETS. They also support other parties' comments on using RTCs without carbon intensities to account for procurement of renewable gas separate from the CI.[158]

Shell does not support allowing separation of the physical gas from the RTCs because RTC markets are currently not sufficiently robust and could lead to lower revenues for producers, discouraging market development.[159]

Electrochaea supports more holistic valuation of emissions reductions, such as providing incentives similar to the LCFS, by providing the Utilities with greater flexibility. This could allow more supply options and create more efficient market pricing. They support keeping the physical gas bundled with RTCs to avoid double counting and improve transparency towards program goals.[160]

LCJA opposes separating the physical gas from the RTCs and states that negative carbon intensities are based on the flawed thinking of industrial dairying.

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[156] SWG Opening Comments at EXH-A - 16-17.

[157] Dairy Cares Opening Comments at 14-15.

[158] Dairy Cares Reply Comments at 7-8.

[159] Shell Opening Comments at 11.

[160] Electrochaea Opening Comments at 9.

They mention concerns of double counting of RTCs that end up attributed to the LCFS and the RGS.[161]

Party comments on the proposed decision highlight the risk of double counting under the proposed unbundling rules.[162] 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.

Parties raise important concerns that highlight a need to further consider details that are not sufficiently present in the record at this time. Considering this, the utilities shall submit proposals via Tier 3 Advice Letter. The proposals should detail how Utilities would implement separately marketing the avoided methane benefits, and how they would address the double counting and exclusive claims concerns raised in comments. The Advice Letter should also propose tracking and reporting requirements.

Finally, we adopt a modified version of the Sempra unbundling proposal. Utilities may purchase market-rate-or-below brown gas from RGS-eligible projects with active RGS contracts, but the volumes must be stripped of all environmental attributes; Utilities cannot count them towards RGS Procurement Targets or claim the Cap and Invest exemption. In these cases, the Developer may retire or market

[161] LCJA Opening Comments at 16-18.

[162] Sierra Club, TURN, PG&E.

the RTCs and associated environmental attributes. As long as the brown gas is purchased at market rate, it does not count towards the CCM. Even though this procurement does not count towards RGS targets, the Utilities shall still submit any brown gas biomethane procurement via a Tier 1 Advice Letter served on the R.13-02-008 service list. These filings should demonstrate that volumes were purchased at or below the market rate for fossil natural gas.

Utilities may also procure brown gas at or below the market rate for fossil natural gas from RGS-eligible projects with active RGS contracts. This procurement can be above the existing contract maximum and/or in excess of the RGS procurement targets. This procurement should also be submitted to the Commission as a Tier 1 Advice Letter served on the R.13-02-008 service list.

### 6.6. Tracking and Forecasting RGS Procurement

As the June 10, 2024 ACR recognized, in comments filed in R.22-12-011, parties raised the issue of avoided natural gas transportation costs from reduced out-of-state natural gas imports resulting from increased procurement of biomethane.

To capture the full value of biomethane procurement for ratepayers, the Utilities would have to decrease natural gas procurement proportionately, which would result in decreased out-of-state imports of natural gas and therefore avoid natural gas procurement, transmission, and pipeline capacity costs. This is not currently possible because the biomethane market (and the Utilities' RGS procurement) is so nascent that accurate forecasts that inform procurement in compliance with system reliability requirements, such as already exist for fossil natural gas in the biennial California Gas Report,[163] are not yet possible. Therefore,

[163] This report is a resource for forecasted and recorded gas volumes consumed in California and is issued annually by the major California gas utilities (https://www.socalgas.com/regulatory/cgr.shtml).

there are likely no avoided costs in this early phase of the RGS program. The June 10, 2024 ACR asked parties to address whether to begin reporting RGS procurement in the California Gas Report, while developing reliable forecasts that would allow proportional reductions in fossil natural gas procurement in meeting system reliability requirements.[164]

Cal Advocates supports requiring biomethane procurement to be tracked in the California Gas Report while biomethane forecasting methodologies are developed.[165] The procurement of excess natural gas and the unnecessarily incurred transmission costs are not in the interest of ratepayers.[166] Cal Advocates contends that the Utilities should have accurate data at their disposal to displace fossil natural gas as accurately and efficiently as possible.[167]

Sierra Club notes the extent of future biomethane procurement is too speculative to forecast for purposes of reliability or avoided gas transportation costs.[168]

Sempra provides, "Understanding the profile of the biomethane supply as a portfolio, rather than focusing on individual contracts, would allow for evaluating the incorporation of biomethane supplies to replace conventional natural gas. This can only be accomplished with multiple supply contacts from utility projects, technologies, and locations. As the biomethane supply portfolio develops, meaningful forecasts for reliability that incorporate biomethane supplies can be developed."[169]

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[164] See June 10, 2024 ACR at 20-21.

[165] Cal Advocates Opening Comments at 4.

[166] Cal Advocates Opening Comments at 4.

[167] Cal Advocates Opening Comments at 4.

[168] Sierra Club Opening Comments at 25.

[169] SoCalGas Opening Comments at 13.

We do believe there is value in reporting. As procurement continues, tracking delivery of biomethane volumes can provide the Commission with information necessary to inform future policy decisions that may reduce ratepayer costs associated with natural gas procurements, imports, transmission and distribution, and capacity reservations in the future. [170]At the same time, the Commission recognizes that RGS procurement is happening in an evolving market. To ensure ratepayers see the full value of RGS contracts, the gas utilities are directed to work with the Commission's Energy Division to track biomethane procurement in each biennial California Gas Report and in their Biomethane Annual Report.[171]

### 6.7. Advice Letter Tiers

The June 10, 2024 ACR asked parties to comment on the Advice Letter tiers and associated thresholds established for RGS procurement contract costs in D.22-02-025. The tier and threshold figures reflect the average market rate of biomethane ($17.70/Million BTUs (MMBtu)) and the social cost of methane as defined by the federal Interagency Working Group (IWG) ($26/MMBtu).[172] As set forth in D.22-02-025, Tier 1 Advice Letters should be used for contracts below $17.70/MMBtu; Tier 2 Advice Letters should be used for contracts between $17.70 and $26.00/MMBtu; and Tier 3 Advice Letters should be used for contracts over $26.00/MMBtu.[173,174] Parties provided comment on the specific Advice Letter tiers.

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[170] 92% of California gas is imported, according to "Natural Gas and California" at https://www.cpuc.ca.gov/industries-and-topics/natural-gas/natural-gas-and-california.

[171] D.22-02-025 Ordering Paragraph 31.

[172] Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990: https://www.whitehouse.gov/wpcontent/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[173] D.22-02-025 at OP 13.

[174] Biomethane Procurement Ruling, Attachment 1 "Draft Staff Proposal."

Waga and Marvel support removing the current Advice Letter tier structure and instead utilize Tier 2 Advice Letters for all contracts moving forward.[175] Similarly, CalBio recommends using a Tier 1 Advice Letter for contracts below $17.70/MMBtu and a Tier 2 Advice Letter for all contracts above this threshold[176]

BAC urges the Commission to remove the current Advice Letter tier structure and replace them with a pricing mechanism that is based on CI.[177] BAC contends this will best further the goal of SB 1440 to cost-effectively reduce SLCP and GHG emissions.[178] CI should, therefore, be the basis for biomethane pricing with lower CI and carbon negative forms of biomethane receiving the highest value under the RGS.[179]

PG&E supports removing the price-based tiers established in D.22-02-025 as these pricing tiers have the potential to influence contract price negotiations with developers.[180] PG&E believes that all biomethane procurement contracts should be submitted to Energy Division through a Tier 2 Advice Letter.[181] Additionally, PG&E recommends tiers based on contract size (i.e., larger contracts would require a Tier 3 Advice Letter) could have unintended consequences of making larger contracts less appealing and slowing the pace of procurement as a Tier 3 Advice Letter requires significantly more support and additional timing for Commissioner approval.[182]

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[175] Marvel Opening Comments at 8; Waga Opening Comments at 11.

[176] CalBio Opening Comments at 11.

[177] BAC Opening Comments at 11.

[178] BAC Opening Comments at 11.

[179] BAC Opening Comments at 11.

[180] PG&E Opening Comments at 7.

[181] PG&E Opening Comments at 7.

[182] PG&E Opening Comments at 7.

Sempra contends that removing the tiered pricing would eliminate potential pricing signals.[183] In SoCalGas's experience, initial feedback from market participants is that the pricing tiers appear more arbitrary to them than substantive.[184] In instances where the pricing was close to tiered pricing, it appeared to send unintended pricing signals.[185] Sempra notes, that shifting to a Tier 2 Advice Letter for approval of all RGS contracts would promote swiftness within the regulatory process, which would ultimately increase participation. Increased participation would, in turn, support the most competitive pricing in biomethane procurement and support further development of the market.[186]

CalBio and Dairy Cares support using Tier 1 Advice Letters for contracts below $17.70/MMBtu and Tier 2 Advice Letters for contracts above that threshold. They do not support basing Advice Letter tiers on contract volumes. Waga supports approving all RGS procurement contracts as Tier 2 Advice Letters and does not believe it is necessary to take contract size into account in terms of advice letter tier.

Sierra Club supports requiring applications in lieu of Advice Letters for all contract submissions.[187] Sierra Club argues that Tier 2 Advice Letters are inappropriate because, per General Order 96-B, Tier 2 is only used for "ministerial acts" that do not require Commission review.[188] Sierra Club believes that biomethane procurement raises significant policy concerns and is far from ministerial, accordingly, careful scrutiny as to whether the contract complies with

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[183] Sempra Opening Comments at 7.

[184] Sempra Opening Comments at 7.

[185] Sempra Opening Comments at 7.

[186] Sempra Opening Comments at 7.

[187] Sierra Club Opening Comments at 16.

[188] Sierra Club Opening Comments at 16 ; referencing Pub. Util. Comm., General Order 96-B, Energy Industry Rules, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M023/K381/23381302.PDF

all aspects of Commission direction and is a cost-effective means of reducing SLCPs, as SB 1440 mandates, is necessary.[189]

Cal Advocates supports all RGS contracts being submitted as Tier 3 Advice Letters for approval because "GO 96-B defines matters appropriate for Tier 3 "[e]xcept as provided in Industry Rule 5.1(4) and in (8) of this Industry Rule, a Contract or other deviation"[190,191] and because "GO 96-B does not state that contracts of any kind are appropriate for Tier 2."[192] Cal Advocates contends that because D.22-02-025 does not authorize any specific contracts or even specify necessary contract language, RGS procurement contracts cannot reasonably be considered ministerial and appropriate for Tier 1.[193] Cal Advocates argues that because GO 96-B does not delegate contract approval via Tier 2 Advice Letters, the Commission should require all RGS procurement contracts via Tier 3 Advice Letters.[194]

LCJA supports all RGS procurement contracts being submitted "for approval as Tier 3 Advice Letters in order to provide the greatest opportunity for oversight from the Commission"[195] and that "…the Commission should review each contract to ensure it is actually achieving the purposes of this program and serving the Commission's prioritization of electrification."[196] They also recommend that each contract be considered at a public Commission meeting.

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[189] Sierra Club Opening Comments at 16

[190] General Order 96-B, Industry Rule 5.3(5)

[191] Cal Advocates Opening Comments at 8-9.

[192] Cal Advocates Opening Comments at 9.

[193] Cal Advocates Opening Comments at 9.

[194] Cal Advocates Opening Comments at 9.

[195] LCJA Opening Comments at 7.

[196] LCJA Opening Comments at 8.

On review, the majority of parties support eliminating the current tiered structure. While parties varied on what the appropriate tier designation, or even procedural path to evaluating biomethane procurement contracts should be, we do agree that biomethane procurement should be reviewed carefully. Although the Commission gave the Utilities the authority to submit tiered Advice Letters that adhere to the RGS program requirements detailed in D.22-02-025,[197] given the nascent stage in the development of the biomethane market, the Commission will require all RGS projects, regardless of volume, to be submitted as Tier 3 Advice Letters. We agree with LCJA that the Tier 3 Advice Letter process provides the correct balance of regulatory oversight and process to ensure ratepayer costs are appropriately considered. This more rigorous Advice Letter process will ensure contracts are reviewed and approved with both utility and stakeholder input. Accordingly, the provisions in OP 13 of D.22-02-025 are modified to require universal usage of Tier 3 Advice Letters for all types of RGS procurement contracts.

Upon reviewing opening comments from parties, the Commission recognizes the concerns mentioned by parties that a Tier 3 Advice Letter process may be unnecessary and slow progress towards the state's SLCP reduction goals.[198] We instead approve a Tier 2 AL approval process, which may enable a more efficient contract review process. If the Tier 2 Advice Letters that are protested or require disposition by resolution the Energy Division may elevate the Advice Letter to a Tier 3, which will be subject to a Commission vote.[199] We believe this strikes the

[197] *See* D.22-02-025 at OP 13.

[198] PG&E at 8, Sempra at 7, Anew at 4, BAC at 7, Waga at 8, CRNG at 8.

[199] Sierra Club Opening Comments on the Proposed Decision at 2. The Protest Process is detailed in GO 96-B §7.4.

appropriate balance of building a successful RGS program while ensuring direct Commission oversight.

### 6.8. Subsidizing Interconnection Costs

The June 10, 2024 ACR asked parties to comment on ratepayer subsidization of biomethane project interconnection costs that are currently the producer's responsibility. As the ruling noted, one significant up-front cost for biomethane producers is the cost of interconnection. An initial $40 million in incentives to support interconnection for biomethane producers was first made available in D.15-06-029 using ratepayer funds, and then another $40,000,000 in incentives was made available in D.20-12-031 from gas IOU Cap-and-Invest allowance proceeds, yielding a cumulative total of $80 million for the Biomethane Monetary Incentive (BMI) Program, all of which have now either been claimed or reserved for utility projects. The BMI waitlist is currently oversubscribed with $37,965,766 in funding requested by developers that is beyond the $80 million previously made available through the BMI.[200] This financial support for biomethane project interconnection costs is available to *all* California projects and has not been specifically applied to reduce market entrance costs for projects intending to enter into RGS procurement contracts.

The Interconnection Cost ACR identified a gap in understanding the interconnection costs and directed the Utilities to answer questions relating to biomethane interconnection project steps and costs. On the issue of ratebasing, except for the SB 1383 dairy pilot projects that were approved pursuant to D.17-12-

[200] https://www.cpuc.ca.gov/industries-and-topics/natural-gas/renewable-gas.

004, interconnection costs are not rate-based.[201] The Utilities currently do not earn a rate of return on any biomethane interconnection costs.[202]

Dairy Cares provides California interconnection costs average two to three times higher than the costs in other states.[203] Developers specifically cite high supervision costs and exorbitant contingency fees as the primary driver of higher interconnection costs in California.[204] Dairy Cares states that some pipeline biomethane interconnection agreements include contingency amounts greatly exceeding the project's projected interconnection costs by as much as one hundred percent.[205] Dairy Cares supports additional funding to help mitigate the barrier to entry from the significant upfront costs without relying on ratepayer funds (e.g., requests for ratebasing interconnection costs by investor-owned utilities).[206] While Dairy Cares does not support broad ratebasing of interconnection costs, they support ratebasing of compressors and other system improvements that provide clean system benefits.[207]

Cal Advocates comments that the Commission should not allocate additional funds to the BMI program through rates or gas IOU Cap-and-Invest allowance funding.[208] Cal Advocates highlights the amount of ratepayer funds that have already been allocated in this proceeding in the form of monetary incentives. Specifically, D.15-06-029 allocated $40 million of ratepayer funds to support

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[201] Sempra Opening Comments on Interconnection Cost ACR at 9.

[202] Sempra Opening Comments on Interconnection Cost ACR at 9; PG&E Opening Comments on Interconnection Cost ACR at 9.

[203] Dairy Cares Opening Comments on Interconnection Cost ACR at 2.

[204] Dairy Cares Opening Comments on Interconnection Cost ACR at 2.

[205] Dairy Cares Opening Comments on Interconnection Cost ACR at 3.

[206] Dairy Cares Opening Comments on Interconnection Cost ACR at 4.

[207] Dairy Cares Opening Comments on Interconnection Cost ACR at 5.

[208] Cal Advocates Opening Comments at 4.

biomethane producers, and D.20-12-031, allocated an additional $40 million of gas IOU Cap-and-Invest allowance proceeds to the BMI program for biomethane producers that would have otherwise been allocated to ratepayers via the California Climate Credit.[209] Cal Advocates notes that if Commission authorizes the most recent round of BMI funding requests, ratepayers will have been required to provide biomethane producers nearly $110 million through the BMI.[210]

Waga believes that projects delivering measurable public benefits, such as methane capture or decarbonization under SB 1440, should be authorized partial rate-basing of system upgrade costs rather than charging developers 100 percent of the expense.[211]

Sempra notes that the Commission could immediately lower interconnection costs by 24 percent by allowing the utilities to ratebase interconnection costs by avoiding the Investment Tax Credit Contribution Agreement (ITCCA) tax.[212] Sempra and PG&E both note that interconnection costs vary primarily due to distance from a suitable pipeline, the type of pipeline system being interconnected to (distribution, transmission, or backbone), and the project location, which affects permitting, land acquisition, and easement expenses.[213] Costs also depend on whether electricity comes from a utility or solar, and whether additional equipment is needed for increased injection capacity into the pipeline, such as reverse compression on the PG&E system.[214]

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[209] Cal Advocates Opening Comments at 4 to 6.

[210] Cal Advocates Opening Comments at 6.

[211] Waga Opening Comments on Interconnection Cost ACR at 5.

[212] Sempra Opening Comments on Interconnection Cost ACR at 14.

[213] PG&E Opening Comments on Interconnection Cost ACR at 5.

[214] PG&E Opening Comments on Interconnection Cost ACR at 5.

Sierra Club disagrees with parties calling for rate-basing of interconnection costs.[215] Sierra Club disagrees with other parties' proposals[216] for tax savings, whereby developers would enjoy from rate-basing, requiring ratepayers cover the cost of long gas-line extensions.[217] Sierra Club contends that there is no justification for such a shifting of costs, especially during a time of rapidly rising utility bills.[218] As the AECA asserted in its comments on the July 10, 2024 ACR, "[r]atepayers should not be burdened with more costs in addition to already expensive biomethane procurement costs."[219] Further, ratebasing could create a perverse incentive for the Utilities to invest in uneconomic projects.[220] Sierra Club highlights parties' claim without support that rate-basing will reduce the cost of biomethane, creating a win for customers.[221] Sierra Club agrees with Cal Advocates' conclusion in comments to the June 10, 2024 ACR that "there is little to no evidence in the record that these incentives will verifiably lead to lower procurement costs."[222] Furthermore, when considering rate-basing, the Commission must keep in mind that biomethane

[215] Sierra Club Opening Comments on Interconnection Cost ACR at 3.

[216] BAC Opening Comments at 5; Waga Opening Comments at 7; Anaergia Opening Comments at 4-5; CRNG Opening Comments at 5; Sempra Opening Comments at 14.

[217] Sierra Club Opening Comments on Interconnection Cost ACR at 3.

[218] Sierra Club Opening Comments on Interconnection Cost ACR at 3.

[219] Sierra Club Opening Comments on Interconnection Cost ACR at 3; AECA, Opening Comments on June 10, 2024 ACR at 6.

[220] Sierra Club Opening Comments on Interconnection Cost ACR at 3.

[221] Sierra Club Opening Comments on Interconnection Cost ACR at 3; CRNG Opening Comments on Interconnection Cost ACR at 4.

[222] Sierra Club Opening Comments on Interconnection Cost ACR at 4; Cal Advocates Opening Comments on June 10, 2024 ACR at 7.

procurement authorized under D.22-02-025 would likely cost over $1.5 billion a year.[223]

PG&E supports the additional allocation of funds to support biomethane producers to interconnect to the utility's gas system.[224] PG&E provides that there are currently 30 projects on the Commission's BMI program reservation list, of which eleven projects, totaling $40 million, are located in PG&E's service territory.[225] Four of the PG&E projects, totaling $14 million, are still on the waiting list for the BMI program.[226] Additional funding for biomethane incentives funds may result in the expansion of the biomethane market and lower biomethane procurement costs.[227] PG&E believes BMI program funding should be prioritized to provide biomethane producers incentive to sell into the RGS Program.[228] The utility notes that any additional funds for interconnection costs will potentially lower the cost barrier in implementing lower GHG emissions in PG&E's service territory.[229]

Considering the statements above, the Commission declines to allow ratebasing of biomethane interconnection costs until demonstrable progress has been made to reduce current interconnection costs and introduce meaningful cost

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[223] Sierra Club Opening Comments on Interconnection Cost ACR at 4; Assuming biomethane costs at the Tier 3 threshold of $26/MMBtu and a Natural Gas Citygate price of $4.34/MMBtu for fossil gas (reflecting past 5-year average Citygate price (https://www.eia.gov/dnav/ng/hist/n3050ca3A.htm) the difference in procurement costs in $21.66/MMBtu. 72.8 BCF of procurement per year = 75,493,600 MMBTU. $21.66/MMBtu * 75,493,600 MMBTU of procurement = $1.635 billion per year. See also See Joint Utilities Opening Comments on Staff Proposal (June 30, 2021) at 3 (estimating $1.5 billion in increased costs by 2030 for a 88 Bcf medium-term target); TURN Opening Comments on Proposed Decision (Jan. 26, 2022), p. 7 (estimating $1.2 billion based on the proposed medium-term target of 88 bcf.).

[224] PG&E Opening Comments at 5.

[225] PG&E Opening Comments at 5.

[226] PG&E Opening Comments at 5.

[227] PG&E Opening Comments at 5.

[228] PG&E Opening Comments at 5.

[229] PG&E Opening Comments at 5.

control measures. While parties clearly demonstrated that California interconnection costs are higher than other states, no party has offered a compelling solution to this problem. Ratebasing interconnection costs potentially decreases transaction costs and provides low-cost financing; however, there is insufficient record on the reasons for higher costs compared to other states. In addition, the record does not support setting specific limits on interconnection costs or supervisory fees at this time, and we note some parties' arguments that each interconnection project has important differences.

The Commission understands that interconnection costs are an obstacle for both producers, who bear the uncertainty and pay the up-front costs of project development, and ratepayers, who eventually see interconnection costs reflected in higher priced RGS procurement contracts. In recognition of this obstacle, this decision orders two next steps. First, the Utilities, in coordination with the Commission's Energy Division, will host a workshop within three months of the date of issuance of this decision on the topic of reducing interconnection costs. The workshop shall include discussion on a cost analysis of interconnection project components, how to showcase more transparent project costs, encourage market competition, and reduce interconnection timelines. The Utilities are ordered to jointly submit a Tier 2 Advice Letter within three months of the workshop date that includes a proposal for reducing interconnection costs, including considerations of any ratepayer costs impact from repaying infrastructure over its lifetime. After this process has concluded, the Utilities may file Applications to ratebase certain interconnection costs.

### 6.9. Third-Party Verification

In D.22-02-025, the Commission directed the Utilities "to include... verifiability... in their respective procurement plans."[230] The SBPM includes a requirement for verification of a wide range of elements, ensuring that the procured biomethane adheres to the requirements of the decision. The ensuing contract between a utility and the producer must be verified by an "officer."[231] However, there is no clear definition of the term "officer" identified in this proceeding. This lack of definition has created confusion. It is unclear whether the officer could include a utility, an uncertified third-party, or the biomethane producers themselves. There is concern that the absence of a clear definition could result in a lack of consistency in reporting quality of biomethane procured for the RGS program, or unqualified or biased entities conducting RGS biomethane verification.

The June 10, 2024 ACR asked parties to address this third-party verification issue, noting that the LCFS program requires third-party verification of fuel attributes, in order to ensure adherence to regulations. The requirements for accreditation of such third parties is defined in 17 CCR Section 95500. This approach aligns with California's Cap-and-Invest Regulation. D.20-12-022 requires third-party verification for the VRNGT program; that requirement is described as follows: "The compliance of purchased RNG supplies with [Mandatory Reporting Regulation] and Cap-and-[Invest] Regulation shall be verified by a third-party independent verification body, accredited by CARB, as required to receive the biomethane exemption under the Cap-and-[Invest] Regulation."[232]

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[230] D.22-02-025 at 35.

[231] PG&E Advice Letter 4626-G, SoCalGas Advice Letter 6003-G, SDG&E Advice Letter 3098-G, and SWG Advice Letter 1222-G, Attachment A, SBPM at 5.

[232] D.22-12-022, Appendix A at A-6.

CRNG supports aligning verification with the LCFS for improved clarity.[233] Sierra Club supports aligning verification with requirements in D.22-12-057's annual reporting provisions.[234] Sierra Club suggests that in the case of receiving regulatory agencies' attestations in ordering paragraph 2(l) and (m), the "officer" referenced in the SBPM should be a representative of the agency and the SBPM should reflect this requirement.[235] Also, any verification should be done by an independent third-party accredited by CARB, as is required for the LCFS, Cap-and-Invest Regulation, and VRNGT programs.

Anew does not support modifications to the definition of "officer," and suggests that the Commission avoid any unnecessary restrictions or requirements in the context of current market constraints.

PG&E does not believe that the term "officer" in the SBPM needs to align with LCFS or VRNGT third-party verification requirement definitions.[236] The additional administrative burden of needing to hire third-party verifiers could have the unintended consequence of reducing biomethane producer participation in the RGS.[237]

Sempra believes it is premature to add additional terms beyond the "officer" requirement. According to Sempra, "At this stage, the focus should be on how the verification will be met rather than adding definition to part of the corporate/financing structure."[238]

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[233] CRNG Opening Comments at 9.

[234] Sierra Club Opening Comments at 5.

[235] Sierra Club Opening Comments at 5.

[236] PG&E Opening Comments at 5.

[237] PG&E Opening Comments at 5.

[238] Sempra Opening Comments at 8.

Cal Advocates requests that the term "Officer" be more specifically defined and align with requirements from the LCFS program. Among the many elements requiring verification are the attributes of a producer's biomethane that result from differing feedstocks and refinement processes, and the expertise needed for this type of verification is very similar to that needed for LCFS verification.[239] Cal Advocates notes that the third-party verification for the VRNGT program to ensure compliance with CARB's Mandatory Reporting Regulation (MRR) and Cap-and-Invest Regulation is less rigorous and less analogous to the verification needed for the SBPM, because the biomethane exemption quoted in the VRNGT's requirements effectively treats all biofuel as having zero CI.[240]

SWG supports specifying that the term "officer" should refer to a Company Responsible Corporate Officer (RCO), as required by the federal Environmental Protection Agency (EPA).[241] The EPA defines an RCO as "a person who is an officer of the corporation under the laws of incorporation of the state in which the company is incorporated, and who in the corporate structure is the person ultimately responsible for the refining, importing, or oxygenate blending activity."[242] This would reduce complexity as the biomethane producers need to follow this definition regardless when reporting to the EPA. On review, the Commission notes that many of the requested modifications are already reflected in the SBPM. The officer attestation referred to in the SBPM is legally binding and includes regulatory reports that would be derived from local air and water boards,[243] in addition to

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[239] Cal Advocates Opening Comments at 9 to 10.

[240] Cal Advocates Opening Comments at 10.

[241] SWG Opening Comments at A-7 to A-9.

[242] See: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/what-definition-responsible-corporate-officer-rco.

[243] SBPM (Advice Letters 626-G, 6003-G, 3098-G, and 1222-G) at 10.

being required to report any incidents of non-compliance with "all applicable federal, state, local air and/or water pollution control standards or requirements."[244]

We agree that there should be more clarity around the term "officer" for purposes of the RGS program. For purposes of biomethane procurement, we adopt the following definition for "officer:"

1. Statutory corporate officers under the California Corporations Code 312;
2. Any executive-level employee; or
3. The "responsible managing officer."

The Commission finds that the current third-party verification structure is sufficient to ensure the level of compliance requested by parties and does not apply additional definitions or requirements at this time.

### 6.10. Facility Natural Gas Combustion

D.22-02-025 precludes the Utilities from procuring biomethane from existing biomethane production facilities that increase their on-site combustion for electricity generation, but it allows for new on-site generation using non-combustion technologies (such as fuel cells and linear generators), and new facilities may use on-site generation from non-combustion technologies. These requirements align with California's broader climate and energy goals. However, these technology requirements may pose a potential barrier to market entrance for biomethane producers.

As the June 10, 2024 ACR recognized, biomethane production facilities that are near population centers would likely have access to the electric grid or be able to connect to it at relatively low cost. However, the SBPM encourages facilities to be

[244] SBPM (Advice Letters 626-G, 6003-G, 3098-G, and 1222-G) at 3

"in a remote location"[245] to avoid local pollution. Such remote facilities may have difficulty connecting to the grid and, as a result, may benefit from off-site facilities combusting natural gas. Parties were requested to comment on questions related to on-site or off-site combustion and exceptions for cost-prohibitive sites.

CRNG supports allowing productive combustion in general because it is preferable to venting or flaring. CRNG further states that that any requirements for combustion should not be overly duplicative of federal, state, or local air permits.

BAC supports allowing combustion generation for onsite power needs, but suggests implementing new requirements for ceramic air filtration technology or other equivalent Best Available Control Technology (BACT). They state that the current restrictions have already prevented at least one project from moving forward because the combustion restriction would have added $100 million to the project costs. Also, WWTPs often have existing excess combustion capacity that cannot be used with the current restrictions, and adding additional non-combustion technology would not be cost effective. BAC goes to add that "Ceramic air filters can reduce NOx emissions by 90 percent or more and particulate matter emissions, including toxic air contaminants, by 97 percent or more."[246]

CalBio supports removing restrictions on combustion, stating that "An absolute restriction on natural gas combustion could be overly restrictive and preclude participation by projects that would otherwise provide emission reduction benefits to the state."[247] CalBio suggests that biogas combustion should be allowed for generation and point out that CARB and local air districts and federal laws already regulate air quality and emissions. CalBio gives an example where a

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[245] PG&E Advice Letter 4626-G, SoCalGas Advice Letter 6003-G, SDG&E Advice Letter 3098-G, and SWG Advice Letter 1222-G, Attachment A, SBPM at 5.

[246] BAC Opening Comments at 13.

[247] CalBio Opening Comments at 13.

biomethane producer may be located close to a large natural gas consumer, and instead of procuring expensive interconnection and pressurization equipment, the facility could reduce costs by interconnecting directly to the large consumer. The fossil natural gas normally procured by the large consumer would be displaced by biomethane, but the environmental attributes could be transferred to the IOU via book-and-claim accounting. CalBio states that it would be a waste of resources to require the biomethane producers in situations like this to interconnect to the California pipeline system.

Sierra Club supports maintaining the complete prohibition on on-site combustion. Sierra Club opposes prioritizing "'market participation' and cost savings for biomethane producers at the expense of Clean Air Act compliance, environmental justice, and the climate."[248] Sierra Club states that it is critical to support emissions reductions and air quality improvements, especially in disadvantaged communities in regions that are already in non-attainment with high levels of local air pollution.[249] They go on to say that non-combustion technologies such as fuel cells exist and can be deployed, ensuring that biomethane producers that cannot connect to the electric grid can still participate in the program.[250] On reply, Sierra Club stresses that the Commission should reject claims that ceramic filters provide greater protections for air quality than a ban on combustion.[251]

Anaergia supports the removal of the ban on combustion generation for onsite power and agrees with BAC on introducing a requirement for BACT, which is already required by local air districts.[252] Anaergia states that the current ban on

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[248] Sierra Club Opening Comments at 21; Sierra Club Reply Comments at 14.

[249] Sierra Club Opening Comments at 21; Sierra Club Reply Comments at 14.

[250] Sierra Club Opening Comments at 21; Sierra Club Reply Comments at 14.

[251] Sierra Club Reply Comments at 14-15.

[252] Anaergia Opening Comments at 12-13.

combustion is impeding project development and is especially challenging for WWTPs that have existing combustion generator capacity onsite that they could otherwise use, instead of investing in additional new non-combustion technology.[253]

Waga supports allowing combustion in order to make more projects financially viable. Waga states that electricity costs in California are extremely high, and it is therefore reasonable for a project to offset some of their electrical load with self-generation based on natural gas combustion.[254] Other projects are remote enough that electrical grid interconnection would be impossible or very costly for the developer and/or ratepayers. Waga suggests that "all projects should be given an opportunity to generate their own electricity if they can receive the required air permits,"[255] especially in a context where California air district regulations are already very stringent.

Marvel supports allowing combustion of natural gas in the case where grid interconnection is prohibitively expensive or the facility needs backup power. Marvel says, "The goal here should be to increase the total number of eligible facilities such that the Utilities can be successful in their procurement journeys, not to unfairly penalize landfills and other facilities who need to preserve energy security on an increasingly unreliable grid."[256]

PG&E supports exceptions for "sites that can demonstrate prohibitive costs for grid interconnection; however, the on-site generation should exclusively be used for the facility to produce biomethane."[257] PG&E points out that "off-site facility natural gas combustion should not be allowed to provide the bypass of utility

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[253] Anaergia Opening Comments at 12-13.

[254] Waga Opening Comments at 21.

[255] Waga Opening Comments at 21.

[256] Marvel Opening Comments at 9.

[257] PG&E Opening Comments at 9.

infrastructure and services, because it could harm customer affordability."[258] They also suggest that air quality and emissions should be considered for facilities near disadvantaged communities.

Sempra supports allowing exceptions for on- and off-site "facility natural gas combustion exception for sites that can demonstrate (i) a reduction of emissions (inclusive of the on-site combustion), and (ii) prohibitive costs for grid interconnection that would materially increase the cost per unit of emissions reduction and/or that would jeopardize the viability of the project."[259] The primary consideration should be ratepayer costs for reducing emissions. Biomethane producers should also have to demonstrate that non-combustion technologies are more costly than any proposed combustion facilities. Exceptions for facilities should be evaluated on a case-by-case basis to determine if there are relevant reliability issues, if the project can demonstrate a net reduction in criteria air pollutants, and if it is located near a disadvantaged community.

SWG supports on- and off-site natural gas combustion exceptions in cases where facilities can demonstrate prohibitive grid interconnection costs. SWG states that this would expand the number of economically feasible projects and reduce the cost of biomethane in California. This would also help avoid producers going to potentially more lucrative markets such as the LCFS. SWG does not believe that additional locational considerations would have a significant impact on SBPM scores, but if any changes were made, they should be made through a another "comprehensive and inclusive workshop effort."[260]

LCJA does not support allowing additional combustion under any circumstances, especially in the San Joaquin Air Basin, which has been out of

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[258] PG&E Opening Comments at 9.

[259] Sempra Opening Comments at 9.

[260] SWG Opening Comments at 9.

compliance with federal air quality standards for decades.[261] LCJA notes that Combustion of biomethane and biogas produces comparable air pollution to combustion of fossil fuels, which would exacerbate the existing disparate health impacts."[262]

Cal Advocates supports allowing combustion in cases where the projects quantify the emissions impact and include it in the CI calculation and local air pollution impacts for inclusion in the SBPM. Cal Advocates points out that comments from various parties on exceptions related to ceramic air filters, avoiding biogas flaring or venting, and others seem reasonable and that "there may be cases in which the benefits of a biomethane project that relies on natural gas combustion for power generation outweigh the drawbacks."[263] They add the following list of suggested SBPM criteria:

- Whether the project is in an Air Quality Management District (AQMD) nonattainment zone;
- The project can use filtration or emissions capture to mitigate pollutants;
- The project can prove that grid intervention and zero-emission fuel cells are prohibitively expensive power sources;
- The project will use only combustion generation to produce biomethane;
- The project will not use fossil natural gas for combustion; and/or
- If the project results in a net reduction of GHGs or SLCPs, or a net increase in local air quality.[264]

[261] LCJA Opening Comments at 9.

[262] LCJA Opening Comments at 9.

[263] Cal Advocates Reply Comments at 6.

[264] Cal Advocates Reply Comments at 6.

While some parties support adding flexibility to the program to allow combustion in select cases, the Commission agrees with Sierra Club and LCJA that removing the combustion prohibition could "exacerbate the existing disparate health impacts"[265] in disadvantaged communities. Taking these considerations into account, the Commission retains the prohibition against combustion for projects.

The Commission does acknowledge the concerns brought up by California Association of Sanitation Agencies (CASA) that WWTPs that begin receiving DOW to provide additional offtake options in accordance with SB 1383 may frequently have excess power production capacity.[266] To encourage WWTPs to accept DOW and accelerate SB 1383 implementation, the Commission authorizes a limited combustion exception for these facilities as follows: WWTPs participating in the RGS program will be permitted to utilize any remaining existing electricity production combustion capacity by adhering to the following requirements:

1. Any combustion must otherwise comply with relevant air quality regulations, including but not limited to the Clean Air Act, CARB nonattainment areas, and local air board regulations.
2. Use filtration technologies, such as – but not limited to - ceramic filters, to ensure the additional combustion produces similar particulate, NOx, and other local pollutant emissions as non-combustion technologies, such as linear generators or fuel cells, or demonstrate that high-efficacy filtration technologies have been explored and determined to be uneconomical and/or ineffective.
3. Include any additional combustion in the full project lifecycle analysis that estimates the project CI.
4. Not produce power from the additional combustion for any purpose other than biomethane production, processing, and upgrading associated with the RGS contract.

[265] LCJA Opening Comments at 9.

[266] CASA Reply Comments at 6-7.

The Commission will remain technology-agnostic to encourage innovation. However, acknowledging concerns brought up by Sierra Club that ceramic filters are a relatively unproven technology,[267] technologies utilized in reducing potential emissions from combustion must base their emissions reductions estimates on a measurable proven track record of use in real-world conditions or be evaluated and approved by an appropriate California agency or local air board.

The Utilities shall jointly file Tier 1 Advice Letters updating their SBPM methodology to ensure that these changes appropriately comport with OP 32 of D.22-02-025; this change shall be included along with other changes ordered pursuant to the instant section of this decision.

### 6.11. SBPM Modifications

The SBPM currently includes a CI variable, but it may not be clear whether the CI variable provides sufficient weighting to represent the real value of biomethane production from low and negative CI feedstocks. However, biomethane price, minimizing ratepayer impact, and low GHG feedstock are significant concerns. The June 10, 2024 ACR directed parties to respond to what SBPM modifications should be implemented.

CRNG supports CI being a more heavily weighted factor in the SBPM. They suggest that GHG performance should be used for setting utility procurement targets in the form of CI targets. They argue that this would be responsive to expansion of approaches that reduce natural gas demand in California, such as energy efficiency and electrification, because any reduction in total natural gas demand would result in lower volumes of biomethane, and in turn lower cost to ratepayers, needed to meet the CI target. Establishing CI targets would also allow all program actors to focus on the primary goal of the program: reducing GHG

[267] Sierra Club Reply Comments at 14.

emissions. CRNG also supports "the removal of geographic distinctions as project scoring"[268] because siting "facilities close to food waste streams can result in environmental, efficiency, and cost benefits for a potential project."[269]

BAC and Anaergia support replacing the SBPM with a CI-based pricing structure, similar to the LCFS. BAC and Anaergia state that prices should reflect the CI of the procured biomethane because the RGS program is fundamentally about reducing carbon emissions. These entities recommend that $/MT-CO2 be the standard of measure. They also mention that tying compensation to CI would encourage biomethane producers to minimize their CI by maximizing efficiencies and utilizing more renewable fuels and low emissions technologies and implementing bioenergy with carbon capture and sequestration (BECCS), as supported by the CARB 2022 Scoping Plan for Achieving Carbon Neutrality.[270]

Sierra Club doesn't support SBPM modifications to increase the weight of CI scoring. Sierra club provides, "more work is necessary to ensure that every biomethane contract entered into by the Joint Utilities is cost-effective and takes into consideration... SLCP reductions, carbon intensity, and air quality improvement in disadvantaged communities."[271] Sierra Club goes on to state that CI is still an indeterminate variable and that the Utilities are "still developing the proposed life-cycle account methodology for biomethane that would presumably lead to the CI scoring for the contracts."[272] They add that any added weight to CI in the SBPM must

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[268] CRNG Opening Comments at 18.

[269] CRNG Opening Comments at 18.

[270] California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality, at 96 (Table 2-3) and at 120.

[271] D.22-02-025 at 26-27.

[272] Sierra Club Opening Comments at 22.

undergo sufficient analysis and stakeholder review and that the RGPPs should receive party comments before approval.

Sierra Club also mentions that in terms of the current SBPM scoring projects far from population centers higher than those that are close, "To the extent more remote facilities avoid adverse impacts to air and water quality, odor and other impacts to vulnerable populations, they should be given higher scores."[273]

Sierra Club states that the Commission should meet SB 1440's requirement for cost-effective biomethane by comparing RGS biomethane with other emissions reductions strategies. They go on to say that there are emissions from "intentionally produced methane"[274] and that "avoided emissions"[275] should not be adopted to assign a negative CI score.

Waga states that the existing landfill gas "CI scoring is unrealistic and should be modified…"[276] to reflect improvements in collection rate efficiency. However, they do not support modifying the current SBPM scoring of carbon intensities. They also recommend removing geographical distinctions between scoring of projects to avoid additional restrictions and difficulties in the biomethane permitting process.

Anew supports avoiding overly prescriptive approaches and instead allowing the Utilities to consider CI among other metrics. They support scoring that encourages the market to maximize emissions reductions. They assert that the Commission should avoid any changes that may inadvertently cause delays in procurement and program scaling. They additionally suggest that the program

[273] Sierra Club Opening Comments at 22.

[274] Sierra Club Opening Comments at 28.

[275] Sierra Club Opening Comments at 29.

[276] Waga Opening Comments at 13.

consider "...immediate and near-term climate benefits of methane abatement, compared with other GHG reductions."[277]

PG&E believes that CI is appropriately weighed in the SBPM.[278] The utility supports remote facilities continuing to be scored higher in the SBPM, but provide a new definition of "remote location" taken from CARB that is "any location more than one-half mile from any business, residence, school, daycare center, or hospital."[279] PG&E suggests the following modifications to the SBPM: extra weight for CA based projects; extra weight for projects that use waste sourced from CA; and extra weight for projects that have a positive impact on disadvantaged communities.[280] PG&E supports including $/ton CO2e in reporting requirements for RGS projects because it allows comparison with other carbon reduction measures and established carbon markets, but does not see the need to modify the SBPM because the CI is already taken into account.[281] PG&E also suggests that procurement should continue to be volumetric because the California gas utility infrastructure is based on volumes of gas, not carbon benefits.

Sempra supports reporting the $/ton value of each RGS project and discussing it as part of the PAG meetings to shed additional light on the costs and benefits of the project.[282] Sempra does not believe the SBPM needs to be modified to include this, but if it is modified, it should go through a similar working group process as the original SBPM development workshop.[283]

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[277] Anew Opening Comments at 14.

[278] PG&E Opening Comments at 10.

[279] CARB, Portable Equipment Registration Program Combined Regulation and ATCM at 8; ww2.arb.ca.gov/sites/default/files/2018-11/Combined RegATCM2018.pdf.

[280] PG&E Opening Comments at 10 to 11.

[281] PG&E Opening Comments at 11.

[282] Sempra Opening Comments at 10.

[283] Sempra Opening Comments at 10.

Sempra supports the continued scoring of remote projects higher than those located close to population centers.[284] This is because of possible project impacts to air quality, water, and noise pollution.

Cal Advocates supports giving CI top priority in scoring to ensure lower CI, which is the primary benefit of biomethane.[285] Cal Advocates suggests that $/ton CO2e values should be reported to the PAGs and included in scoring of solicitation bids.[286] Cal Advocates also support modifying scoring of remote projects with "score weighting that favors projects with lower-polluting facilities or plans to mitigate localized pollution impact."[287]

SWG believes that CI is currently appropriately weighted in the SBPM and does not support related modifications.[288] SWG provides that $/ton is already considered in the SBPM through application of the CI and the social cost of carbon.[289]

LCJA recommends that the SBPM prioritize projects that avoid negative local impacts, especially to disadvantaged communities, regardless of their location. It should use a "science-based, project-specific standard"[290] to accomplish this. LCJA also supports evaluating biomethane's carbon impact cost efficiency and recommend using carbon accounting that "does not include so called avoided methane emissions and negative carbon intensity."[291]

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[284] Sempra Opening Comments at 10.

[285] Cal Advocates Opening Comments at 11.

[286] Cal Advocates Opening Comments at 11.

[287] Cal Advocates Opening Comments at 11.

[288] SWG Opening Comments at A-9.

[289] SWG Opening Comments at A-9.

[290] LCJA Opening Comments at 11.

[291] LCJA Opening Comments at 11.

Most parties supported including a $/ton avoided carbon equivalent cost-effectiveness metric in some form in the SBPM or increasing the impact of CI on scoring. Some also argued that CI is adequately considered in the current SBPM, while others argue that CI benefits are overestimated and negative carbon intensities do not exist. Many suggested that any modifications of the SBPM should go through a similar workshop process to the SBPM's original development, which was required in D.22-02-025.[292]

The Commission agrees with Sierra Club that CI is not the only relevant variable in RGS procurement and that local environmental impact, especially to vulnerable communities, is an important consideration and should not be removed from the SBPM. BAC and Anaergia support replacing the SBPM with a CI-based pricing structure, similar to the LCFS. The Commission agrees that CI is critical in a program whose primary goal is GHG and SLCP reductions through the replacement of fossil natural gas with biomethane.

SB 1440 begins by establishing the broader context of the bill, which resulted in establishment of the RGS program, with a focus on biomethane use and the associated reduction of GHG and SLCP emissions as follows: "Existing law requires state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of renewable gas. Existing law requires the Commission, in consultation with the State Energy Resources Conservation and Development Commission and the State Air Resources Board, to consider additional policies to support the development and use in the state of renewable gas that reduce short-lived climate pollutants in the state." SB 1440 goes on to require that in exploration of establishing what would become the RGS program, "The targets or goals are cost-effective means of achieving the forecast

[292] D.22-02-025 at OP 1 and OP 2.

reduction in the emissions of short-lived climate pollutants... and other greenhouse gases...”

However, the “sustainable production” required by SB 1440 and subsequent Commission decisions clearly show that evaluation and minimization of local pollution impacts need to remain an important part of the RGS solicitation process. D.22-02-025 established that local environmental pollution, alongside the cost effectiveness of biomethane procurement and other considerations, is a critical RGS procurement consideration and directed the Utilities to “include in the Standard Biomethane Procurement methodology assessments of the ways in which [project developer] biomethane procurement practices affect the environment and increase or decrease the welfare of local communities, including the positive or negative ways in which modifications to a wastewater treatment plant or landfill to increase biomethane production affect those Communities.”[293]

The SB 1440 GHG and SLCP cost effectiveness requirements for RGS biomethane indicates that the intended focus of the program was GHG and SLCP reductions, and that cost-effectiveness should be a primary consideration in program procurement. The Commission reaffirms the need for considering local pollution impacts while ensuring that GHG emissions reductions cost effectiveness is adequately considered as required by SB 1440 and also recognizes that $/ton of avoided emissions is an important cost-effectiveness metric to track.

Volumetric above-market costs of biomethane will continue to be considered as well because ratepayer burden is driven by these figures and therefore limited by the CCM discussed in Section 6.1. However, once proposed procurement can pass the CCM, it should be evaluated strategically to drive the most cost-effective outcomes, per SB 1440’s cost effectiveness requirements.

[293] D.22-02-025 OP 32.

The Commission directs the Utilities to include the $/ton of avoided carbon equivalent value of a project in Procurement Advisory Group (PAG) meeting presentations and RGS contract Advice Letter submissions. The $/ton value will not be directly incorporated into the SBPM but will rather be used as a comparison point for Energy Division staff and the Commission.

### 6.12. RGS Out-of-State Procurement Considerations

Pub. Util. Code Section 651 requires SB 1440-associated biomethane procurement to demonstrate environmental benefits to California, including: (1) the reduction or avoidance of the emission of any criteria air pollutant, toxic air contaminant, or GHG in California; (2) the reduction or avoidance of pollutants that could have an adverse impact on California waters; and (3) the alleviation of a local nuisance within California that is associated with the emission of odors.[294] Parties were requested to weigh-in on whether out-of-state biomethane procurement could benefit to both the market and ratepayers in California.[295]

BAC provides that SB 1440 is quite clear that the capture or production of biomethane must reduce climate, air, water or odor pollution in California.[296] In other words, the RGS program should simply use the definition of local environmental benefits that is provided by SB 1440 itself.[297] BAC provides a list of types of out-of-state projects that could provide local environmental benefits. These projects generally use organic waste generated in California or near the state border.[298] Examples include: biomethane generated from forest or agricultural

[294] SB 1440, Pub. Util. Section 651(b)(3)(B)(ii).

[295] *See* June 10, 2024 ACR at 17.

[296] BAC Opening Comments at 15.

[297] BAC Opening Comments at 15.

[298] BAC Opening Comments at 16.

waste in a neighboring state where the burning of that waste or wildfires could cause air or water pollution in California; the conversion of California's DOW to biomethane; and converting livestock manure to biomethane in neighboring states where the livestock waste causes pollution or odors that affect California.[299]

Sempra and PG&E argue that any biomethane (regardless of its source) displacing fossil fuels in a common carrier pipeline "should be viewed as providing local environmental benefits."[300] Any out-of-state biomethane project that can demonstrate local environmental benefits should be considered eligible for RGS procurement (addressed on a case-by-case basis).[301] This includes projects that (1) use organic waste that originates in California (both diverted and non-diverted), (2) decrease the transportation distance of waste that originates in California even if that waste is being disposed to an out-of-state facility (lowering emissions from transporting waste), and (3) replace an out-of-state disposal site for waste that originates from California with a disposal site that reduces the overall emissions and/or negative impacts on local communities (i.e., air/water pollution), even if the reduction of overall emissions or negative impacts are on communities out-of-state.[302] In these examples, while there are environmental benefits that may be generated for out-of-state communities, the diversion of organic waste from California landfills results in a local environmental benefit. Lastly, since about ninety (90) percent of our gas supplies in California are sourced from out-of-state, one could claim that any biomethane that displaces fossil fuels should be viewed as providing local environmental benefits.

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[299] BAC Opening Comments at 15 to 16.

[300] Sempra Opening Comments at 11; PG&E Opening Comments at 12.

[301] Sempra Opening Comments at 11.

[302] Sempra Opening Comments at 11.

CRNG supports defining local benefits as having any impact in the state of California, which can originate in other states, including "upstream watershed impacts, regional air quality impacts... the utilization of co-products such as fertilizer or other soil amendments within California in a manner that supports state climate, air quality, water quality, and sustainable agriculture goals."[303] CRNG urges the Commission to remain "open to diversifying our RNG supply portfolio and allow in-state supply to compete fairly with (or be supplemented by) out-of-state supply, if such resources can deliver equivalent environmental benefit."[304]

CalBio states that SB 1440 requirements for local environmental benefits in California in the case of common carrier pipeline delivery are clear and highlights that the local environmental benefits required by the legislation must be the direct result of capture and production of biomethane, as opposed to the end-use. CalBio does not recommend changing the definition already given in SB 1440.[305]

Sierra Club recommends that the Commission use the Renewable Portfolio Standard (RPS) definition of local environmental benefit for the RGS program as established in Chapter 2.C.3(c) of the RPS Eligibility Guidebook furbished by the California Energy Commission (CEC).[306] This definition requires either a peer-reviewed publication referencing a specific local environmental benefit that can be associated with the given project or empirical evidence of such a benefit.[307]

On reply, Dairy Cares focuses on the statutory provisions of RGS procurement and contends that opening-up procurement on the basis that SLCP reductions out-

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[303] CRNG Opening Comments at 19.

[304] CRNG Reply Comments at 6.

[305] CalBio Opening Comments at 16-17.

[306] CEC, RPS Eligibility, Ninth Edition (Jan. 2017), https://efiling.energy.ca.gov/getdocument.aspx?tn=217317.

[307] Sierra Club Opening Comments at 24.

of-state broadly improve California's environmental conditions are inconsistent with the statute. Pub. Util. Code Section 651(b)(3) states that biomethane must either be delivered through a "California dedicated pipeline" or a "common carrier pipeline."[308] When injecting into a common carrier pipeline, the statute requires that the common carrier pipeline physically flows to California and the seller (or purchaser) must demonstrate that the "capture or production" of biomethane directly results in at least one of three enumerated environmental benefits to California.

TURN agrees with BAC and AECA that there is no need to develop a new comprehensive definition of local environmental benefits because the statutory language "is clear on its face and the burden should be on the project developer to show compliance."[309] TURN also agrees with Sierra Club that the Commission may rely on the CEC's RPS Eligibility Guidebook demonstrate compliance with the local environmental benefit showing.[310] They state that that approach recognizes that the statutory requirements for local environmental benefits in SB 1440 are identical to the statutory provisions governing biomethane eligibility under the RPS program and that given the similar statutory language, there is no basis for adopting a different (and weaker) environmental benefits standard under SB 1440 than under the RPS program.[311]

To align eligibility requirements across energy programs, the Commission directs the Utilities to rely on the CEC's RPS Eligibility Guidebook to demonstrate compliance with the Pub. Util. Code Section 651 requirement stating that the project should demonstrate environmental benefits to California. Accordingly, the seller or

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[308] Dairy Cares Reply Comments at 6.

[309] TURN Reply Comments at 3; ACEA Opening Comments at 4.

[310] TURN Reply Comments at 3; Sierra Club Opening Comments at 24.

[311] TURN Reply Comments at 3.

producer must demonstrate one of the following benefits to California: (1) the reduction or avoidance of the emission of any criteria air pollutant, toxic air contaminant, or GHG in California; (2) the reduction or avoidance of pollutants that could have an adverse impact on California waters; (3) the alleviation of a local nuisance within California that is associated with the emission of odors.[312]

### 6.13. RGS Procurement and Landfill Eligibility Requirements

In D.22-02-025, a medium-term target requirement determined that "Landfill gas procurement will be limited to landfill facilities that stop accepting new organic waste and implement advanced landfill gas capture automation and monitoring technology to decrease fugitive methane emissions."[313] The intention of this requirement was to avoid creating perverse incentives that would result in organic waste being intentionally funneled *to* landfills, despite the fact that SB 1383 requires municipalities to divert organic waste *away* from landfills.

Imposing additional specific requirements on landfills in an effort to support SB 1383 requirements may be inappropriate when considering that SB 1383 directed the California Department of Food and Agriculture that they "Shall not establish a numeric organic waste disposal limit for individual landfills."[314] Due to the infeasibility of filtering out all organic waste from refuse delivery to landfills, in practice the D.22-02-025 requirement for RGS-participating landfills to receive no organic waste limits RGS procurement to closed landfills. This reality may limit competition in RGS procurement and potentially drive up costs for ratepayers. Parties were directed to address whether landfills should continue to be required to stop accepting new organic waste to be eligible for RGS procurement; and if this

[312] SB 1440, Pub. Util. Section 651 (b)(3)(B)(ii).

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

[314] California Public Resources Code Section 42652.5(a)(3).

requirement is removed, what other modifications should be considered to prevent perverse incentives and support SB 1383 implementation.

Sempra provides that landfills should not be required to stop accepting new organic waste to be eligible for RGS procurement.[315] The SB 1383 regulation puts the responsibility on the jurisdictions to meet the 75 percent organic waste diversion rate from landfills by 2025.[316] Sempra notes that there is no regulation in place requiring jurisdictions to divert 100 percent of organic waste from landfills. Until such regulation is in place, most active landfills will likely continue to receive some volume of organic waste.[317] Sempra purports that allowing landfills that are accepting new organic waste to be eligible for RGS procurement can help capture, condition, and upgrade the landfill gas into biomethane, which could then be injected into a natural gas pipeline.[318] Finally, if no changes to landfill eligibility is adopted, Sempra requests the Commission to better define "landfill facilities." As it stands, landfill facilities operate from retired sections of the landfill.[319]

BAC urges the Commission to not limit RGS procurement to landfills that no longer accept organic waste.[320] BAC feels this limit would exclude most landfills and prevent the capture and beneficial use of the biomethane generated at those landfills.[321] BAC urges the Commission to remove the restriction on landfill gas and to replace it with a CI-based pricing mechanism to reflect the fact that landfill gas is less expensive than other forms of biomethane, but also much higher CI on a

[315] Sempra Opening Comments at 14.

[316] Sempra Opening Comments at 14.

[317] Sempra Opening Comments at 14.

[318] Sempra Opening Comments at 14 to 15.

[319] Sempra Opening Comments at 15.

[320] BAC Opening Comments at 18.

[321] BAC Opening Comments at 18.

lifecycle basis.[322] BAC comments that removing the restriction while ensuring that the price of biomethane reflects the lower climate value of landfill gas is the appropriate way to further the goals of both SB 1440 and SB 1383.[323]

Sierra Club contends that the limit on landfill eligibility for RGS procurement is necessary to avoid providing perverse incentives for landfills to deposit new organic waste in landfills in order to create and sell methane.[324] Sierra Club believes that relaxing landfill eligibility requirements would run counter to SB 1383 and SB 1440's goals of DOW and reducing SLCPs.[325] Sierra Club notes that "methane point source emissions in California are dominated by landfills (41 per cent)" and "the largest methane emitters in California are a subset of landfills, which exhibit persistent anomalous activity."[326]

PG&E is unsupportive of the limitation placed on landfills for RGS procurement. The utility comments that the requirement for landfills to stop accepting new organic waste to be eligible for RGS procurement is unclear at the implementation level in that even an inadvertent admission of organic waste via existing sources of landfill category waste would render the landfill ineligible to supply biomethane under the RGS program.[327] To ensure that removing this requirement does not result in any self-beneficial incentives for landfills and to ensure continued support for SB 1383 implementation, PG&E recommends that landfills be required to submit, as part of their offers, an executive officer-level

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322 BAC Opening Comments at 18.

323 BAC Opening Comments at 18.

324 Sierra Club Opening Comments at 27.

325 Sierra Club Opening Comments at 27.

326 Sierra Club Opening Comments at 27, citing Duren, R.M., Thorpe, A.K., Foster, K.T. et al. California's methane super-emitters. Nature 575, 180–184 (2019). https://doi.org/10.1038/s41586-019-1720-3.

327 PG&E Opening Comments at 16.

certification regarding SB 1383 compliance.[328] This certification may be in the form of an attested letter to Cal Recycle or the local jurisdiction where the project would be located, stating that the participating landfill operates in compliance with the SB 1383 requirements.[329]

Anew believes that the requirement should be modified to align with realistic conditions in the market.[330] The continued lack of comprehensive organic waste diversion infrastructure cannot be cured entirely by relying on restrictions in the biomethane procurement program.[331] Anew contends that it is counterproductive to insist on restrictions that cannot possibly be met, and as a result leave potential methane abatement CO2e tons on the table.[332] As mentioned at the outset of this section, the intention of the landfill eligibility requirements adopted in D.22-02-025 was to avoid creating perverse incentives that would result in organic waste being funneled to landfills. However, parties commented on the infeasibility of filtering out all organic waste from refuse delivery to landfills, and how limiting this eligibility criteria can be. Recognizing the smaller pool of eligible landfill sites that could participate in RGS procurement under D.22-02-025's landfill eligibility criteria, this definition makes an adjustment to ensure ratepayers are not burdened with additional costs attributed to a small landfill market. SB 1383 does not require zero organic waste in landfills, but a 75 percent reduction over time.

We recognize party comments urging the Commission to modifies the D.22-02-025 landfill eligibility and allow open landfills to participate in RGS

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[328] PG&E Opening Comments at 16.

[329] PG&E Opening Comments at 16.

[330] Anew Opening Comments at 12.

[331] Anew Opening Comments at 12.

[332] Anew Opening Comments at 12.

solicitations.[333] We acknowledge that landfill gas is comparatively lower in cost, and is a readily available feedstock. Therefore, we allow Utility procurement from open landfill projects, contingent on some implementation steps detailed below.

To clarify existing short-term and DOW target procurement requirements, the Commission defines "SB 1383-compliant biomethane" to be termed derived from organic waste that has been processed at an in-vessel digestion facility that is permitted or otherwise authorized by Title 14 to recover organic waste, meets the requirements of Public Resources Code section 40106, or has been determined to constitute a reduction in landfill disposal pursuant to 14 CCR section 18983.2.

To that end, we direct the Utilities to submit a proposal for landfill procurement that addresses possible perverse incentives around landfills participating in the RGS program as a Tier 2 Advice Letter within three months of this decision. The Utilities should work with CalRecycle and Energy Division Staff to develop a proposal that: (1) establishes clear SB 1383 compliance certification requirements for participating landfills; (2) proposes monitoring or reporting mechanisms to detect increases in organic waste acceptance attributable to RGS participation; ; and (3)) includes any other elements deemed necessary and reasonable for effective and safe participation of landfills in the RGS in alignment with broader state goals. If the proposal satisfies those conditions, Utilities may begin including landfill projects in RGS solicitations.

The Commission also recognizes Sierra Club's concerns about the possibility of landfill methane capture rates falling as a result of the initiation of a biomethane project.[334] In response, we direct the Utilities to ensure that the CPUC-GREET model will take into account real-world methane capture rates in calculating carbon

[333] Sempra at 2.

[334] Sierra Club Opening Comments at 10.

intensity, with landfill biomethane projects that demonstrate decreased capture rates after one year of operation disallowed from participation in the RGS program.

### 6.14. Modifications to RGPPs

Given the modifications to the RGS program, the Commission directs the Utilities to amend their draft RGPP filings to reflect the RGS program changes made via this decision. Notwithstanding D.22-02-025's direction that the "Utilities shall submit their final RGPPs as Tier 1 Advice Letters,"[335] we opt to modify that prior direction to instead require a Tier 2 Advice Letter filing to help ensure that the substantive changes being made to the RGS program by the instant decision are accurately reflected in the Utilities' Advice Letter filings. In comments on the proposed decision, PG&E requests additional time to file its modified RGPP.[336] That request is granted. Consistent with D.22-02-025, the Utilities shall file their modified final RGPP filings within 90 days of issuance of this instant decision via Tier 2 Advice Letter.

## 7. 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. As of February 13, 2026 there have been eight public comments filed in the instant proceeding. Each of the comments provides different recommendations to the Commission regarding the rulemaking. The first commenter is generally supportive of the instant proceeding and expresses the need for a faster interconnection process for RGS contracts. The second two comments encourage

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[335] D.22-02-025 at 40.

[336] PG&E Opening Comments on Proposed Decision at 6.

the Commission to accept wood waste for the program. The rest of the comments focus on a UC-Riverside report entitled "Hydrogen Blending Impacts Study" and statements from the American Biogas Council.

## 8. Conclusion

On review, the RGS program established by D.22-02-025 identified biomethane procurement as a cost-effective tool for reducing short-lived climate pollutants, pursuant to SB 1440 and Section 651 of the Public Utilities Code. But that decision did not sufficiently grapple with the ratepayer impacts of biomethane procurement, which is necessary for any cost effectiveness evaluation. The Commission also bears responsibility for protecting ratepayers from excessive above market costs. This decision balances affordability matters and the Commission's obligations under 651 by adjusting the procurement targets and establishing a Cost Containment Mechanism that sets a limit on average and maximum customer rate impacts. The final decision also takes steps to develop the RGS market by clarifying rules, authorizing procurement of biomethane from non-DOW feedstocks, and authorizing a Tier 2 Advice Letter approval process. This decision advances the key goals of SB 1383 and D.22-02-025 by taking steps that cost effectively support reductions in SLCP emissions.

The Commission notes that the question of how the above-market costs and environmental benefits associated with biomethane procurement should be allocated among the full range of customers sharing the common carrier pipeline network remains an important policy question that is beyond the scope of this proceeding. The Commission expects that that question will receive full consideration in the appropriate forum, R.22-12-011.

Taken together, the modifications adopted today recalibrate the RGS program to further the state's SB 1383 goals, while fulfilling the Commission's enduring obligation to protect ratepayers from excessive procurement. Ratepayers will continue to contribute meaningfully to California's biomethane market development and SLCP reduction goals, but at a reasonable scale and cost level.

## 9. Procedural Matters

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.

## 10. Comments on Proposed Decision

The proposed decision of Commissioner John Reynolds 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. Opening Comments were filed on March 26, 2026 by Anew RNG, LLC, PG&E, Anew Climate, Agricultural Energy Consumers Association and Dairy Cares, California Bioenergy, Sierra Club, Sempra Utilities, Bioenergy Association of California, Southwest Gas Corporation, Waga Energy, MRETS, CRNG, SCGC, TURN, Leadership Council for Justice and Accountability, Electrochaea. Reply comments were filed on April 1, 2026 by Sempra Utilities, Agricultural Energy Consumers Association and Dairy Cares, Leadership Counsel for Justice and Accountability, Sierra Club, Bioenergy Association of California, Electrochaea Corporation, and PG&E. Clarifications have been made throughout the decision in response to comments.

We recognize one issue brought-up by Sempra here. Sempra notes that the proposed decision does not provide any process for reviewing the results of RGS and proposing a path forward. The Commission appreciates this comment, and directs the Utilities to prepare a report reflecting RGS procurement orders. The Utilities shall file this report via a Tier 2 Advice Letter on or before June 30, 2028. This report must be served on the service list for this proceeding, and Rulemaking 21-12-011.

## 11. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Sasha Goldberg is the assigned Administrative Law Judge in this proceeding.

## Findings of Fact

1. According to CARB's 2023 GHG Inventory, California's residential and commercial gas customers emitted 2.6 percent of statewide methane emissions in 2023.
2. The CARB Scoping Plan envisions biomethane primarily as a means to decarbonize hard-to-electrify end uses, including industrial processes.
3. PG&E's cost containment mechanism, as proposed in their draft RGPP, can limit RGS bill impacts for customers and prevent unaffordable procurement.
4. The short-term target adopted in D.22-02-025 cannot be met by 2025 considering delays in SB 1383 implementation by 2025.
5. DOW feedstocks have been slow to materialize and RGS procurement is far below targets established in D.22-02-025.
6. Reduction to the overall target procurement volume from 72.8 Bcf annually to 36.4 Bcf annually will protect ratepayers from incurring excessive above market costs in a nascent market.
7. The adopted adjustments to the procurement targets will maintain the RGS program focus on DOW, as envisioned by SB 1383, by leaving the DOW target unchanged.
8. The 2040 contract delivery limit established in D.22-02-025 restricts the effective term of contracts signed after 2025, reducing the period over which developers can recover capital costs and therefore increasing per-unit procurement prices.
9. Most California biomethane projects include 20-year interconnection agreements with Utilities.

10. M-RETS is currently the only commercially available platform capable of tracking and verifying RGS biomethane procurement volumes and preventing double-counting of environmental attributes.

11. The Cap-and-Invest Regulation exemption for biogenic CO2 from biomethane combustion credits only a portion of the carbon intensity, and does not credit any avoided methane emissions.

12. The local environmental benefits in SB 1440 are similar to the statutory provisions governing biomethane eligibility under the RPS program and the California Energy Commission's RPS Eligibility Guidebook.

13. In practice, the D.22-02-025 requirement for RGS-participating landfills to receive no organic waste limits RGS procurement to closed landfills.

14. The BMI waitlist is oversubscribed by $37.97 million.

15. California interconnection costs average two to three times higher than in other states.

16. The tiered Advice Letter structure in D. 22-02-025 created pricing signals that undermined competitive solicitations.

17. Tier 2 Advice Letter review provides Commission oversight and stakeholder participation through the protest period, which is appropriate for novel procurement contracts in a nascent market.

18. Wastewater treatment plants (WWTPs) that begin accepting diverted organic waste pursuant to SB 1383 may have existing excess combustion capacity that cannot currently be utilized under D.22-02-025's prohibition.

19. Ceramic filtration and equivalent technologies may reduce emissions from combustion but their effects require additional study before they are considered proven.

20. The dollar-per-ton of avoided CO2 equivalent is an established metric for evaluating SLCP cost-effectiveness.

21. SB 1383 does not require zero organic waste in landfills but rather a 75 percent diversion rate over time, making a complete organic waste prohibition on RGS-eligible landfills inconsistent with the underlying statutory requirement.

## Conclusions of Law

1. It is reasonable to implement an RGS CCM with the following attributes.
   a. The CCM establishes, for each Utility, two independent tests that must each be satisfied before the Commission will approve new RGS procurement: a 1 percent Program Cost Cap and a 3 percent Annual Increase Cap. The CCM is the controlling constraint on biomethane procurement, and the Commission will not approve new procurement that would cause a Utility to fail either test;
   b. For purposes of both tests, the above market cost of a given RGS contract is calculated as the difference between the contract's total delivered price per unit and the prevailing forward price for fossil natural gas at the applicable delivery point, less the avoided cost value of any cap-and-invest exemption savings associated with the biogenic gas;
   c. This per-unit premium — reflecting the above-market cost paid specifically for climate benefits — is multiplied by the contract's expected annual delivery volumes to yield the annual above market cost for that contract. Annual above market costs are aggregated across all active RGS contracts in the utility's portfolio to determine the total annual above market cost for year *n*;
   d. The CCM tests are applied at the time of contract submission. The calculation window for each test begins with program year 1, defined as 2022 consistent with the effective date of D.22-02-025, and extends through the final delivery year of the proposed contract. For years within the calculation window with actual delivery data, above market costs are recorded portfolio above market costs. For future years, above market costs are forecasted above market costs for expected delivery volumes;
   e. The 1 percent Program Cost Cap is calculated as follows: for each year *n* in the calculation window, the Utility shall

compute the running program average of above market costs from program year 1 through year *n*, defined as the simple average of above market costs. This running average is expressed as a percentage of the Renewable Gas Cost Allocation Pool revenue requirement in year *n*. If this future exceeds 1 percent in any year within the calculation window, the CCM fails the Program Cost Cap test and the Commission will not approve the proposed procurement.

f. The Renewable Gas Cost Allocation Pool revenue requirement is initially defined as the Non-Natural Gas Vehicle Bundled Core Customers revenue requirement. Future Commission action may revise the Renewable Gas Cost Allocation Pool.

g. The 3 percent cap for maximum increase is calculated as follows: for each year *n* in the calculation window, the Utility shall compute the year-over-year change in above market costs as a percentage of the prior year's combined base of Renewable Gas Cost Allocation Pool revenue requirement plus that year's above market costs. If the figure exceeds 3 percent in any year within the calculation window, the CCM fails the Annual Increase Cap and the Commission will not approve the proposed procurement, regardless of the result of the Program Cost Cap test.

h. The Commission will not approve new procurement that would cause a Utility to fail either CCM test.

i. Brown gas biomethane purchased at the market rate has no above market cost and therefore does not count towards the CCM.

2. It is reasonable to direct the Utilities to jointly propose a standardized rate impact calculation template, and to direct the Utilities to coordinate with the Commission's Energy Division to develop this standardized template.

3. It is reasonable to allow the Utilities to propose technical fixes to the CCM via Tier 2 Advice Letter, as long as those fixes preserve the core principles of the CCM described in Conclusion of Law 1.

4. It is reasonable to allow the Utilities to procure from all feedstocks immediately without first meeting the short-term DOW procurement target established in D.22-02-025.
5. It is reasonable to extend procurement for the DOW target and overall target to 2035.
6. It is reasonable to reduce the overall procurement target from 72.8 Bcf annually to 36.4 Bcf annually.
7. It is reasonable to modify the procurement targets for the purpose of reducing the overall responsibility of ratepayers for above-market costs of biomethane procurement and to ensure that the core policy interests of SB 1383 are advanced and that non-ratepayer funding pathways are optimized.
8. It is reasonable to modify the RGS program to allow for procurement contracts for deliveries extending beyond 2040.
9. It is reasonable to allow the Utilities to propose a new biomethane tracking system other than M-RETS by a joint Tier 3 Advice Letter filing.
10. It is reasonable for the Cap-and-Invest Regulation exemption associated with the biogenic source of the biomethane to only be claimed by the Utilities and *not* by biomethane producers or marketers.
11. It is reasonable to allow Utility proposals on how to market avoided emissions attribute of biomethane. The Utilities may submit a proposal via Tier 3 Advice Letter. The proposal should ensure that ratepayers exclusively pay for and claim credit for the biogenic source of the gas, avoid any double counting concerns, and should also propose tracking and reporting requirements.
12. It is reasonable to expect that limited unbundling of biomethane contracts should drive ratepayer prices lower.

13. Brown gas biomethane purchased at market rate does not count towards the CCM, but it cannot count towards RGS procurement targets or receive the Cap and Invest exemption.

14. It is reasonable to direct the Utilities to work with the Commission's Energy Division to track biomethane procurement in the California Gas Report and the Biomethane Biennial Report.

15. It is reasonable to modify the provisions in OP 13 of D.22-02-025 to require universal usage of Tier 2 Advice Letters for all types of RGS procurement contracts.

16. Declining to ratebase biomethane interconnection costs is reasonable.

17. Directing the Utilities to host a workshop focused on reducing interconnection costs in coordination with the Commission's Energy Division is reasonable.

18. It is reasonable to allow the Utilities to file an Application to ratebase certain interconnection costs after their proposal for reducing interconnection costs is approved.

19. For biomethane procurement, it is reasonable to adopt the following definition for officer:

    a. Statutory corporate officers under the California Corporations Code 312;
    b. Any executive-level employee; or
    c. The "responsible managing officer."

20. It is not reasonable to allow additional combustion on RGS projects.

21. It is reasonable to allow wastewater treatment plants to utilize any remaining existing electricity production combustion capacity combustion for biomethane production processes in the RGS program, as long as these facilities meet the following requirements:

    (a) Any combustion must comply with air quality regulations, including but not limited to the Clean Air Act and CARB nonattainment areas.

(a) Use filtration technologies, such as – but not limited to - ceramic filters, to ensure the additional combustion produces similar particulate, NOx, and other local pollutant emissions as non-combustion technologies, such as linear generators or fuel cells, or demonstrate that high-efficacy filtration technologies have been explored and determined to be uneconomical and/or ineffective;

(a) Include any additional combustion in the full project lifecycle analysis that estimates the project CI; and

(a) Not produce power from the additional combustion for any purpose other than biomethane production, processing, and upgrading associated with the RGS contract.

22. It is reasonable to direct the Utilities to include the $/ton of avoided carbon equivalent value of a project in Procurement Advisory Group (PAG) meetings and RGS contract submissions via Tier 2 Advice Letter.

23. The modification to allow projects close to populations centers to receive the full scoring in the SBPM if the project can demonstrate net local emissions benefits for the health and wellbeing of local communities is reasonable.

24. The directive for the Utilities to modify their respective SBPM via Tier 1 Advice Letter is a reasonable procedural pathway.

25. Reliance on the CEC's RPS Eligibility Guidebook to demonstrate compliance with Pub. Util. Code Section 651's requirement that the project should demonstrate environmental benefits to California is reasonable.

26. The Cap & Invest Regulation exemption for biogenic fuels does not consider CI and therefore RTCs containing the CI can be marketed separately without double counting the benefits.

27. It is reasonable to modify the RGS program to allow for active/open landfill participation, contingent upon an approved Utility proposal.

28. Directing the Utilities to submit a proposal addressing possible perverse incentives around open landfills participating in the RGS program as a Tier 2 Advice Letter is reasonable.

29. It is reasonable to direct the Utilities to amend their RGPPs pursuant to the modifications adopted in these Conclusions of Law.

30. The RGS program established by D.22-02-025 identified biomethane procurement as a cost-effective tool for reducing short-lived climate pollutants, pursuant to SB 1440 and Section 651 of the PU Code.

31. It is reasonable for the Utilities to file a report on RGS procurement via Tier 2 Advice Letter by June 30, 2028.

32. It is reasonable to affirm all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding.

33. It is reasonable to deny all motions not ruled on in this proceeding.

## O R D E R

**IT IS ORDERED** that:

1. The Renewable Gas Standard Program established by Commission Decision 22-02-025 is modified as described in the Conclusions of Law of this decision.

2. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the "Utilities") are directed to procure 36.4 Billion cubic feet (Bcf) of biomethane annually by 2035, including 17.6 Bcf of biomethane from diverted organic waste feedstocks. This procurement order supersedes those adopted in Ordering Paragraphs 14-18 in Decision 22-02-025 and must comply with the Cost Containment Mechanism as described in the Conclusions of Law of this decision.

3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the "Utilities") shall coordinate with the Commission's Energy Division to create a

standardized reporting template to measure rate impacts across the Utilities' customer classes for the purposes of the Cost Containment Mechanism. The Utilities shall jointly submit a Tier 1 Advice Letter to the Commission's Energy Division to implement this standardized reporting template within six months of issuance of this decision. The Utilities shall copy the Service Lists for Rulemaking 13-02-008 and Rulemaking 22-12-011 on this Advice Letter filing.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation shall coordinate with the Commission's Energy Division to track biomethane procurement in each biennial California Gas Report, beginning with the 2028 California Gas Report.

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the "Utilities") shall submit any contracts for biomethane procurement via Tier 2 Advice Letter to the Commission's Energy Division. This supersedes the tiered review process established by Ordering Paragraph 13 of Decision 22-02-025. The Utilities must copy the Service Lists for Rulemaking 13-02-008 and Rulemaking 22-12-011 on this Advice Letter filing.

6. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the "Utilities") shall coordinate with the Commission's Energy Division to host a workshop focused on reducing interconnection costs within six months of issuance of this decision. The Utilities shall submit a Tier 2 Advice Letter to the Commission's Energy Division within three months after the workshop to reflect their proposal for reducing interconnection costs. The Utilities must copy the Service Lists for Rulemaking 13-02-008 and Rulemaking 22-12-011 on this Advice Letter filing.

7. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the

"Utilities") shall file a Tier 1 Advice Letter within 90 days of the date of issuance of this decision to reflect the modifications adopted for the Standard Biomethane Procurement Methodology (SBPMs). The Utilities must copy the Service Lists for Rulemaking 13-02-008 and Rulemaking 22-12-011 on this Advice Letter filing.

8. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the "Utilities") shall file a Tier 2 Advice Letter with the Commission's Energy Division within three months of issuance of this decision including a proposal for how to include landfills in Renewable Gas Standard procurement. The Utilities shall coordinate with CalRecycle and the Commission's Energy Division to develop this proposal, and an approved proposal will allow the Utilities to include open landfill projects in  renewable gas standard solicitations. The Utilities must copy the Service Lists for Rulemaking 13-02-008 and Rulemaking 22-12-011 on this Advice Letter filing.

9. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (*collectively*, the "Utilities") shall file their amended Renewable Gas Procurement Plans (RGPPs) to implement the modifications adopted in the Conclusions of Law within 90 days of issuance of this decision. The amended RGPPs must be filed via Tier 2 Advice Letter. The Utilities must copy the Service Lists for Rulemaking 13-02-008 and Rulemaking 22-12-011 on this Advice Letter filing.

10. Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Gas Company, and Southwest Gas Corporation (collectively, the "Utilities") shall prepare a report reflecting Renewable Gas Standard procurement orders.  The Utilities shall file this report via a Tier 2 Advice Letter on or before June 30, 2028.  This report must be served on the service list for this proceeding, and Rulemaking 21-12-011.

11. This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding and deems all motions not ruled on in this proceeding as denied.

12. This proceeding remains open.

This order is effective today.

Dated , at San Francisco, California