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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

ASSIGNED COMMISSIONER'S RULING SEEKING COMMENTS REGARDING THE RENEWABLE GAS STANDARD PROGRAM AND DECISION 22-02-025 ISSUES

Summary

This assigned Commissioner's ruling seeks to inform the review of the pending Renewable Gas Procurement Plans (RGPPs) and work towards identifying improvements to the Renewable Gas Standard (RGS) program structure. This ruling revisits some elements of Decision (D.) 22-02-025's implementation of the RGS program structure, and explores pathways for the program to best reach its goals. Some of the issues addressed in this ruling seek to increase market competition, reduce market barriers for biomethane producers, improve quantification methodologies, improve alignment with external regulatory goals, streamline procurement, and maximize benefit to ratepayers.

Specifically, this ruling directs parties to file comments responding to the questions set forth in this ruling. Comments will be considered in this proceeding to inform the Commission's review of the pending RGPPs, and may lead to modifications to the RGS program. Parties are directed to file opening comments responsive to this ruling by July 19, 2024, and reply comments may be

filed by August 9, 2024. Parties' opening and reply comments must be structured such that it follows the structure of this ruling in identifying the ruling section, repeat of each question to be followed by corresponding response.

A proposed decision regarding the pending RGPPs and possible RGS program modification is anticipated in Q4 of 2024.

1. Background

On November 21, 2019, the assigned Commissioner issued a Scoping Memo and Ruling initiating Phase 4 of this proceeding (Phase 4 Scoping Memo). It identified three specific action items necessary to implement Senate Bill (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 California Public Utilities Code (Pub. Util. Code) Section 651 (b). On June 5, 2020, the assigned Commission issued a subsequent Amendment to Phase 4 Scoping Memo, 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: Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E)/Southern California Gas Company (SoCalGas)(together, Sempra Utilities), 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 D.22-02-025. It directed the adoption of an RGS program to implement SB 1440. On April 5-6, 2022, in compliance with D.22-02-025, Ordering Paragraph (OP) 1, a workshop was held concerning the Standard Biomethane Procurement Methodology (SBPM) and the RGPP.

On July 5, 2022, the Utilities respectively submitted proposed SBPMs through Advice Letters 626-G, 6003-G, 3098-G, and 1222-G. These Advice Letters were approved on December 28, 2022.

On December 28, 2022, pursuant to D.22-02-025, OP 31, the Utilities submitted draft RGPPs. These draft RGPPs have not yet been approved. Pursuant to D.22-02-025, the Commission is expected to issue a decision in response to the draft RGPPs, "providing specific instructions to each of the utilities for what to modify or include in their final RGPP."[1]

On July 20, 2023, a 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.

2. Discussion

RGS procurement solicitations have been moving forward in accordance with D.22-020-025, 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.

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[1] D.22-02-025 at OP 31.

In furtherance of examination of these developments, we set forth below a series of questions designed to explore pathways for the RGS program to increase market competition, reduce market barriers for biomethane producers, improve quantification methodologies, improve alignment with external regulatory goals, streamline procurement, and maximize benefit to ratepayers.

2.1. Procurement Alignment With SB 1383

D.22-02-025, OP 14 directs the Utilities to procure 17.6 billion cubic feet of biomethane derived from 8 million tons of organic waste diverted from California landfills to meet the short-term portion of the RGS program target. This direction was in support of SB 1383 (Lara, 2016), which requires reduced organic waste and recovery of biomethane feedstock released from organic waste.

SB 1383 was intended to be implemented by providing a recipient market for California Department of Resources Recycling and Recovery's (CalRecycle) biomethane feedstock by 2025.[2] Although this recipient market outlet will be needed in the future, these CalRecycle feedstocks are not currently available in sufficient quantities to support the RGS program's short-term procurement goals due to delays in SB 1383 implementation. At this time, 126 California districts have received extensions for their compliance deadlines.[3]

In time, SB 1383 will continue to ramp up, expanding the available quantity of landfill-diverted organic waste feedstocks, while simultaneously facilities are continuing to be constructed to receive and process this feedstock.

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[2] "Lowering Costs of Food Waste Codigestion for Renewable Biogas Production": https://ww2.energy.ca.gov/2020publications/CEC-500-2020-069/CEC-500-2020-069.pdf.

[3] https://calrecycle.ca.gov/organics/slcp/progress/.

As these activities develop over time, this resource should become a larger part of RGS program procurement. Meanwhile, due to feedstock limitations, ratepayer costs for such feedstock will foreseeably rise due to lack of solicitation competition.

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 Utility procurement solicitations, potentially increasing biomethane available for procurement, increasing competition, and reducing ratepayer costs.

Also, there is a question regarding the definition of SB 1383-derived biomethane feedstocks. By defining the eligible "SB 1383-derived" feedstocks as adhering to 14 California Code of Regulations (CCR) §§ 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, it 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.

Parties are directed to respond to the below questions regarding SB 1383 alignment:

A. Should the short-term target procurement restrictions be relaxed to mirror medium-term target procurement requirements as defined in D.22-02-025?

B. If short-term procurement restrictions are relaxed to mirror medium-term procurement, how should prioritization of SB 1383-derived biomethane be ensured without inducing artificial price inflation? Should the SBPM be modified to reflect this prioritization?

C. Should feedstocks have to adhere to 14 CCR §18982(a)(46), 18982(a)(62), 18983.1(b), and 18993.1-18993.4, and be verified by a third-party independent verification body accredited by CARB, to be considered "SB 1383-derived" for RGS procurement?

2.2. Contract Timelines

While the nascent California biomethane market may be ready for rapid growth, unlocking capital to build and operate biomethane processing plants can be a significant hurdle. Numerous parties have commented on the importance of the financial stability provided by long-term contracts in order to induce greater investor participation.[4]

As directed by D.22-02-025, OP 56, RGS solicitation contracts are limited to 15 years, as biomethane delivery pursuant to RGS is not to extend beyond 2040. Therefore, to enter into a 15-year contract ahead of that 2040 deadline, all activities necessary to supply the biomethane would need to be completed by 2025. However, there is reasonable concern that due to necessary lead times for capital acquisition, facility construction, and permitting, there may not be sufficient opportunity to complete these activities within that timeline.

In addition, given the newness of the biomethane market, there are likely opportunities for biomethane production cost reduction over time. We can expect to see workforce expertise, construction techniques, supply chains, and

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[4] Parties' Opening Comments to the proposed decision preceding D.22-02-025: AECA at 4-5; True North Renewable Energy at 10; California Bioenergy at 4; Anaergia Services at 8; Dairy Cares at 5; and Joint IOUs at 9-10.

feedstock availability develop as the market expands, and regulatory and permitting barriers should lessen over time. These factors should benefit ratepayers by inducing greater competition for lower-cost procurement.

As presently required by D.22-02-025 to meet the defined short-term and medium-term RGS targets, the Utilities must front-load the majority of their biomethane procurement. Procuring the majority of RGS biomethane before the market matures may result in unnecessarily high ratepayer costs.

The impact of the 2040 procurement contract deadline should also be considered. Because the Utilities would have to enter into shorter and shorter contracts as the deadline approaches, that reality has the potential to offset the cost reductions otherwise gained from market maturation. The potential to enter into reduced-cost procurement contracts over time may suggest a benefit to enabling the Utilities to procure more gradually, while maintaining the option for long-term contracts.

Given the additional context of California's increasing electrification, procuring biomethane up to and beyond 2040 also raises issues regarding biomethane customer demand. These electrification efforts may result in medium-term RGS procurement requirements that exceed customer demand.

Therefore, it is important to ensure that the program is sufficiently flexible so as to reduce the procurement requirement if and when it is no longer needed. Possible solutions could be to allow the Utilities to sell excess biomethane to Voluntary Renewable Natural Gas Tariff (VRNGT) customers or California-based or out-of-state industrial, large commercial, or other customers.

Parties are directed to respond to the below questions regarding adjusting contract timelines:

A. How should procurement be structured to take advantage of potential biomethane cost reductions as the market matures? Should short-term and medium-term target timing be modified to reflect these changes?

B. Should the 2040 deadline be extended or eliminated, to allow for contracts to fulfill 15 years of biomethane delivery?

C. How could program flexibility be added to avoid biomethane procurement in excess of customer demand?

D. How should the Commission weigh the impacts of developing biomethane on other policy goals, such as electrification?

2.3. Subsidizing Interconnection Costs

One significant up-front cost for biomethane producers is the cost of interconnection. $40,000,000 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 Cap-and-Trade allowance proceeds, yielding a total of $80,000,000 for the Biomethane Monetary Incentive (BMI) Program. These funds have now either been used or have been reserved for ongoing projects, and an additional $29,600,000 has been requested. This financial support for biomethane project interconnection costs has not been specifically applied to reduce market entrance costs for RGS procurement.

In the response to this proceeding's July 20, 2023 Ruling, the Utilities put forward proposals with the intention of reducing procurement costs. PG&E proposed that additional funding be set aside to support interconnection costs from Cap-and-Trade program allowance auction proceeds for biomethane producers in a way that would allow associated savings to be passed on to customers. It noted that D.20-12-031 gave the Commission discretion to apply

Cap-and-Trade allowances to GHG reduction programs that meet CARB regulatory requirements, which includes the RGS procurement requirement.[5]

Also in response to the July 20, 2023 Ruling, SoCalGas/SDGE proposed rate-basing biomethane interconnection costs, citing Pub. Util. Code Section 399.24(a): "To meet the energy and transportation needs of the state, the Commission shall adopt policies and programs that promote the in-state production and distribution of biomethane." They argued that this is a just and reasonable investment to support biomethane production, and that it is necessary because the gas intertie 24% Income Tax Component of Contributions and Advances (ITCCA) tax exemption is ending.[6]

Pub. Util. Code Section 784.2 requires the Commission to consider whether to allow recovery in rates of the costs of investments to the investments necessary to meet the goals of Pub. Util. Code Section 399.24. The Commission previously determined in D.19-12-009 that:

> At this time, the Commission does not have adequate information to [determine whether or not to allow recovery in rates of the costs of investments necessary to facilitate interconnection of biomethane production facilities], although […] projects are currently underway that will provide the relevant information.[7]

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[5] D.20-12-031 Conclusion Of Law 8.

[6] The IRS is no longer applying the safe harbor principles under IRS Notice 2016-36 to gas interties. As a result, SoCalGas gas interties are now subject to ITCCA (the 24% ITCCA tax): https://www.irs.gov/pub/irs-drop/n-16-36.pdf.

[7] D.19-12-009 at 9.

D.19-12-009 also stated that "As more projects take advantage of these incentives, this will provide additional information to inform the Commission's evaluation under Section 784.2."[8]

The parties' proposed approaches would reduce the initial cost barrier to market entrants. In a developing market such biomethane, elimination or reduction of such capital barriers may be critical for increasing market competition and to drive down costs. Rate-basing interconnection costs could serve as a form of pass-through for ratepayers if biomethane producers passed on their savings to customers through lower biomethane contract costs. Further subsidizing of interconnection costs with Cap-and-Trade allowance proceeds could also act as a form of pass-through.

However, applying either of these incentives could affect the program in other ways as well, raising additional issues that would benefit from party input. For instance, some facilities may request these funds with the intention of only providing a portion of their biomethane production to RGS activities, and therefore it is unclear whether they should be eligible. Also, previous interconnection incentives were limited to 50% of interconnection costs: it could be possible to continue this approach, or to increase or decrease the incentive contribution. Further, projects may have very different interconnection costs based on their location. For instance, the SBPM encourages remote projects to avoid possible local pollution impacts to customers, but remote projects may also incur higher interconnection costs.

Parties are directed to respond to the below questions regarding possible subsidizing of interconnection costs:

[8] D.19-12-009 at 10.

A. Should additional funds be allocated toward the existing BMI Program? If so, what should the funding source(s) be? Should future BMI subsidies be made exclusively available for production facilities selling biomethane for the RGS program?

B. In addition to or as an alternative to the BMI Program, should the Commission consider other forms of funding mechanisms for recovery of biomethane production facility interconnection investment costs -- as examples, either through recovery in rates pursuant to Pub. Util. Section 784.2, or through Cap-and-Trade funds, or through other forms of funding?

C. Should any of the possible interconnection funding mechanisms discussed in the immediately preceding Question B be limited to facilities that will be exclusively providing biomethane for RGS procurement (e.g., not facilities also participating in the Low Carbon Fuel Standard (LCFS) program market, or selling to non-core customers, or selling biomethane outside of the RGS)? Alternatively, should possible interconnection funding mechanisms be adjusted to take into account biomethane producers' non-RGS engagement?

D. How can we ensure that biomethane producer savings associated with any possible interconnection subsidies would result in lower biomethane procurement costs?

E. Should any of the possible interconnection funding mechanisms discussed in the preceding Question 3.2 be modified to account for specific characteristics of a production facility -- as examples, based upon facility size, or facility location?

F. Should the SBPM be modified to take into account interconnection costs and possible subsidies?

2.4. Removal Of Advice Letter Tiers

D.22-02-025 provides Advice Letter tiers and associated thresholds as bases for RGS biomethane procurement contract costs. These 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 Federal Interagency Working Group's (IWG) ($26/MMBtu).[9,10] 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.

The RGS procurement process was designed with the intention to minimize costs to ratepayers by facilitating market development and competition. That intention may be advanced by removing potentially inadvertent price signals sent to the market by these tier thresholds, which may have created confusion in the procurement process. We are seeking party comments regarding possible removal of potentially confusing signals to the market, including possibly removing the Advice Letter tier submission requirements.

Parties are directed to respond to the below question specific to removal of Advice Letter tiers:

A. Should all RGS contracts be submitted to the Commission for approval as Tier 2 Advice Letters in order to avoid sending potentially inadvertent price signals to the market?

B. Should there instead be Advice Letter tiers established based on contract size in terms of MMBtus procured? What should those specific tier thresholds be? Would this send

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

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

any inadvertent signals to the market that we should avoid?

2.5. Cost Caps

The July 20, 2023 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. (These confidential responses are available to this proceeding's non-market participant parties who are RGS solicitation Procurement Advisory Group (PAG) members.) The Utilities' proposed cost caps vary widely.

Parties are to respond to this question specific to cost caps:

A. Should the Commission consider a single consistent cost cap for all Utilities or should the Utilities be able to use different cost caps?

B. If a single cost cap were to be applied to all Utilities, which of the proposed cost caps should be adopted?

2.6. Third-Party Verification

In D.22-02-025, the Commission directed the Utilities "to include... verifiability... in their respective procurement plans."[11] The Utilities were also directed to response to the following question in the subsequent RGPP/SBPM workshop: "What criteria shall be used in the biomethane procurement plan to verify project viability, high uptime, and accurate deliverability of promised volume of biomethane?"

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

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

verified by an "officer."[12] However, there is no clear definition of the term "officer." 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, or unqualified or biased entities conducting RGS biomethane verification.

The CA 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 CCR Title 17, § 95500. This approach aligns with the CA Cap-and-Trade program.[13]

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-Trade 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-Trade Regulation."[14] (Emphasis added.)

Parties are directed to respond to this question specific to third-party verification:

A. Should "officer," as used in the SBPM as the agent responsible for contractual and legal compliance verification, be defined in more specific terms? Should this

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

[13] https://ww2.arb.ca.gov/lcfs-verification.

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

definition align with the LCFS, or should it align with the VRNGT, or should a new definition be created?

2.7. Off-Site Facility Natural Gas Combustion

D.22-02-025 OPs 39 and 40 preclude RGS procurement from existing biomethane production facilities that increase their on-site combustion for electricity generation, but they may install new on-site generation using non-combustion technologies (such as fuel cells), and new facilities may use on-site generation from non-combustion technologies. This stance is in line with CA's broader climate and energy goals. However, we may consider revisiting these technology requirements, as they may pose a potential barrier to market entrance for biomethane producers.

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 "in a remote location"[15] 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 are to respond to this question specific to off-site facility natural gas combustion:

A. Should there be any on-site facility natural gas combustion exception for sites that can demonstrate prohibitive costs for grid interconnection?

B. Should there be any off-site facility natural gas combustion exception for sites that can demonstrate prohibitive costs for grid interconnection?

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

C. What considerations, such as cost, reliability, and availability of alternative sources of energy, should be considered regarding allowing on-site or off-site combustion? Should location, air quality, emissions, and proximity to a disadvantaged community be considered as well?

2.8. SBPM Modifications

The SBPM currently includes a carbon intensity (CI) variable, but it may not be clear whether it provides sufficient weighting to represent the real value of biomethane production from low and negative CI feedstocks. Biomethane price and minimizing ratepayer impact is a significant concern in procurement. However, low GHG feedstock is also a significant concern.

Additionally, as discussed in Section 2.7, locating biomethane facilities in areas far from population areas may be important for limiting local pollution impacts to communities,[16,17] but can also create additional costs associated with pipeline interconnection and either grid connection or electricity generation through the use of non-combustion technologies. Feedstock proximity is often critical because feedstock transport to biomethane production facilities is inherently expensive. Locating facilities in remote areas may be proximately advantageous for woody biomass processes that draw feedstocks from forest management, but facilities processing municipal feedstocks pursuant to SB 1383 may need to be closer to populations hubs. Currently, the SBPM has an adder that supports facility projects sited in a remote location.

Parties are to respond to these questions specific to the SBPM:

A. Is carbon intensity appropriately weighted in the SBPM? Should the SBPM be modified to increase the weight of

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16 Advice Letters 4626-G, 6003-G, 3098-G, and 1222-G, SBPM at 5.

17 D.22-02-025 OPs 3, 32.

carbon intensity in scoring? How exactly should it be modified?

B. Should the SBPM continue to score remote projects higher than those located close to population centers?

C. Are there any other modifications that should be considered for the SBPM?

2.9. RGS Out-of-State Procurement Considerations

Pub. Util. 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.[18]

While this foreseeably limits RGS procurement to areas within California or in proximity to California, it is unclear as to what constitutes adherence to Pub. Util. Section 651's enumerated requirements.

As a possible means to encourage the biomethane market available to the Utilities in order to try to increase competition and drive down costs for ratepayers, a specific set of definitions of what the California air quality, water quality, and nuisance impacts and benefits may be considered for out-of-state biomethane to be eligible for procurement.

Parties are directed to respond to the below questions specific to RGS out-of-state procurement:

A. How should a definition of what constitutes local environmental benefits according to SB 1440 be developed?

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

B. What types of out-of-state projects could provide local environmental benefits to CA? For example, could a project in a neighboring state that uses CA feedstocks and provides biomethane to CA be eligible? What would those benefits be? What additional issues should be considered?

C. Should the SBPM be modified to reflect adherence to the definition of local environmental benefits provided to CA?

2.10. Encouraging RGS Market Participation

This Ruling focuses largely on measures to optimize RGS procurement to encourage market development, increase competition, and drive down costs to ratepayers.

Parties are directed to respond to this below question specific to encouraging RGS market participation:

A. In considering RGS market participation, how can solicitation participation be encouraged across potential biomethane producers including among various jurisdictions, private entities, and others?

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

The SBPM includes direction for producers to track volumetric injections of biomethane via Midwest Renewable Energy Tracking System (M-RETS).[19] 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,"[20] 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.

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

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

However, in its August 21, 2023, response to the July 20, 2023 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."

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,"[21] and creates attribution required for the registration of Renewable Thermal Certificates (RTC), 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.

Parties are directed to respond to the below questions specific to M-RETS alternatives:

A. What options that exist on the market today should be considered as an alternative to M-RETS for RGS procurement verification and tracking of environmental credits?
B. What entity, public or private, would be best suited for creating a new system? What process would be required to develop such a system?
C. What additional issues should be taken into consideration regarding tracking volumetric injections of biomethane?

[21] SoCalGas and SDG&E's December 28, 20222, Draft Renewable Gas Procurement Plan.

2.12. Tracking and Forecasting RGS Procurement

In their comments to the 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 proportionally, which would result in decreased out-of-state imports of natural gas and therefore avoided upstream transmission costs. This is not currently possible because the biomethane market (and in particular the Utilities' RGS biomethane procurement requirement) is so nascent that accurate forecasts that inform procurement in compliance with system reliability requirements, such as already exist for natural gas in the CA Gas Report,[22] are not yet possible. Therefore, there are likely no avoided upstream transmission costs in this early phase of the procurement program.

One possible path forward would be to begin reporting RGS procurement in the CA Gas Report, while developing reliable forecasts that would allow proportional reductions in natural gas procurement in meeting system reliability requirements. This could lead to avoided transportation costs.

Parties are to respond to the below question specific to tracking and forecasting RGS procurement:

A. What is best path forward for incorporating biomethane procurement into reliability forecasts for the purpose of

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[22] 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).

reducing natural gas procurement in proportion to biomethane procurement?

2.13. Linking RGS procurement and the Voluntary Renewable Natural Gas Tariff Program

On February 28, 2019, the Sempra Utilities filed Application (A.) 19-02-015, requesting approval to establish a VRNGT program, enabling their residential, small commercial, and industrial customers to purchase biomethane as part of their regular gas services. On December 17, 2020, Commission issued D.20-12-022 and authorized a three-year pilot VRNGT program for the Sempra Utilities. This program was intended to help municipalities and industrial and commercial facilities to meet environmental goals while supporting the development of the growing California biomethane market.

However, program restrictions may continue to present barriers to procuring biomethane at competitive prices. D.20-12-022 approved a three-year VRNGT pilot, but disallowed program wind down costs to be transferred to ratepayers, stating that these costs should be the Utilities' shareholders' responsibility. Yet, D.20-12-022 also stated:

> We will provide more time for the Utilities to decide whether to implement the RNG Tariff program, and to submit the program implementation details... This allows the Utilities more time to evaluate whether there are opportunities for long-term contracting for the pilot program in conjunction with any procurement that might be authorized in the proceeding implementing SB 1440.[23]

Because D.22-02-025 initiated RGS procurement in D.22-02-025, we believe it is appropriate to now revisit the issue of potential VRNGT program wind down costs and potential links between the programs. According to parties in

[23] D.20-12-022 at 25-26.

A.19-02-015, the short three-year VRNGT pilot program time frame, in conjunction with the requirement that all program wind down costs are to be borne by Utilities' shareholders, may result in short-term, high-cost contracts, undercutting the effectiveness of this program in delivering biomethane to customers who select it on a voluntary basis. These potentially high costs could disincentivize customers from engaging with this program, despite the fact that the Utilities are well-positioned to aggregate biomethane purchases for customers who may not have the capacity or organizational know-how to navigate that market. By allowing a portion of the program wind down costs to be transferred to ratepayers in the event that the VRNGT program is not extended beyond its three-year pilot, the Utilities would be able to sign long-term low-cost contracts that could provide a more competitive price for customers.

As discussed in D.20-12-022, ratepayers should be protected from costs accrued due to VRNGT program wind down.[24] However, stranded long-term contracts procured to fulfill VRNGT program needs could be transferred over to RGS procurement with no additional costs to ratepayers, as long as the proper protections were in place. For example, a contract's procured biomethane could be transferred to ratepayers to meet RGS goals, but at the current biomethane market price at that time, as opposed to the original contract price. In a scenario in which the original contract price may be higher than the current market price at that time, the price difference could be borne by Utility shareholders, removing any additional cost to ratepayers, reducing risk to shareholders, and encouraging the beneficial functioning of the VRNGT program.

[24] D.20-12-022 at 25-26.

This proposed change may encourage the Utilities to sign long-term, low-cost contracts for the VRNGT program, which would in turn help develop the biomethane market and deliver lower biomethane prices to ratepayers over the long term. "Current market price" would have to be defined and calculated for each relevant contract for transfer from the VRNGT program to the RGS. A possible definition could be the average procurement cost of biomethane from the same feedstock over the previous year's RGS procurement.

Similarly, it may also be beneficial to allow the transfer of biomethane contracts from the RGS to the VRNGT program. With this added flexibility, the Utilities may be able to take advantage of economies of scale to sign low-cost contracts that exceed their RGS targets, thereby meeting the RGS while also having the ability to transfer excess biomethane to the VRNGT program to support customers seeking to meet other environmental goals. This allowance may also require protections to ensure that excess costs don't fall to ratepayers: for example, any costs associated with contracted biomethane volumes exceeding the RGS targets would be borne by Utility shareholders if the VRNGT program was unable to find interested customers.

If the VRNGT program is extended beyond its three-year pilot, the greater flexibility proposed here could benefit ratepayers in the face of long-term market uncertainty.

Parties are to respond to these questions specific to linking RGS procurement and the VRNGT Program:

A. Should the Commission allow VRNGT-procured biomethane to be transferred to the RGS? If so, what protections should be put in place to protect ratepayers? In what situations should this be allowed/disallowed?

B. Should the Commission allow RGS-procured biomethane to be transferred to the VRNGT? If so, what protections should be put in place to protect ratepayers? In what situations should this be allowed/disallowed?

2.14. RGS Procurement 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."[25] The intention of this requirement was to avoid creating perverse incentives that would result in organic waste being funneled to landfills, despite that SB 1383 requires municipalities to divert organic waste away from landfills. Yet there may be a concern that while SB 1383 requires jurisdictions to divert organic waste away from landfills, landfills are not directly regulated by the legislation.

Therefore, supporting SB 1383 by imposing additional requirements on landfills may be inappropriate. Due to the infeasibility of filtering out all organic waste from refuse delivery to landfills, in practice this requirement limits RGS procurement to closed landfills. This reality may limit competition in RGS procurement and potentially driving up costs for ratepayers.

Parties are to respond to this question specific to RGS procurement landfill eligibility requirements:

A. Should landfills continue to be required to stop accepting new organic waste to be eligible for RGS procurement? If this requirement is removed, what other modifications should be considered to prevent perverse incentives and support SB 1383 implementation?

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

2.15. Regulatory Barriers

The Commission would like to elicit a full list of regulatory and market barriers that may hinder the development of this biomethane market, for consideration in the development of possible further Commission policy.

Parties are to respond to these questions specific to regulatory barriers:

A. What market barriers exist in the biomethane market? How should they be overcome?

B. What regulatory barriers exist in the biomethane market? How should they be overcome?

2.16. Equitable Pipeline Capacity Access

Further development of the biomethane market in California requires access to natural gas pipeline interconnection. Here, we consider possible barriers to equitable access to pipeline interconnection capacity.

Currently, potential projects request pipeline capacity from the Utilities at a given interconnection point. Capacity is determined on a first-come, first-served basis. Project developers are required to demonstrate progress toward project delivery, with the intention of preventing the reservation of capacity beyond the amount that the developers could use, thereby maximizing the utility of the pipeline's actual capacity to deliver gas to customers.

A potential market inefficiency may occur if a private pipeline connected to the utility pipeline system over-reserves capacity, and then sells that excess capacity to market entrants (who could otherwise have interconnected directly to the Utility's pipeline system, but were unable to due to the private pipeline's over-reservation) on the spot market at a premium. The additional cost of connecting through the private pipeline would be passed along to customers in the form of higher biomethane costs. In the long-term, this inefficient and costly practice could slow the development of the biomethane market.

Parties are directed to respond to these questions specific to equitable pipeline capacity access:

A. Should private pipeline operators be allowed to over-reserve capacity and sell that capacity at a profit to gas producers seeking pipeline interconnection?

B. How can over-reservation of pipeline capacity be prevented? How can pipeline access be equitably ensured for all gas producers?

C. SoCalGas's Advice Letter 5845[26] recategorized RNG in Rules 30 and 45 and expanded available pipeline capacity for RNG interconnections. Should the other IOUs engage in similar modifications to their tariffs?

D. Should environmental impact and/or carbon intensity be considered in the capacity reservation process?

2.17. Incorporating Avoided CO2e Value as an RGS Program Metric

D.22-02-025 directed the Utilities to host workshops to guide the development of the SBPM, including "analysis of factors such as the price of natural gas, costs associated with transporting the gas, the cost of biomethane, the cost of emissions compliance, and the carbon intensity (CI) of the biomethane." The SBPM currently focuses on the cost of biomethane and associated above-market costs. The direct comparison with natural gas is important to consider in understanding program costs to be borne by ratepayers. However, these figures are not fully helpful in clarifying carbon impact cost efficiency and therefore making it difficult to enable useful comparisons with other low-carbon renewable resources.

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[26] https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/submittals/GAS_5845.pdf.

SB 1440 requires that the RGS "targets or goals are cost-effective means of achieving the forecast reduction in the emissions of short-lived climate pollutants."[27] By additionally considering the $/ton of CO2e cost of biomethane and/or the $/MMBtu value of CO2e abatement, the climate impact of this resource could be better understood, and direct comparisons with energy efficiency, solar, wind, and other comparable resources could be possible, thereby enabling RGS program to better align with SB 1440 requirements. This analysis could also help guide RGS procurement and focus solicitations on low-carbon biomethane.

Parties are to respond to these questions specific to incorporating $/ton CO2e and/or $/MMBtu value of CO2e abatement as an RGS Program Metric:

A. Should the Utilities include $/ton CO_2e cost of procurement and/or $/MMBtu value of carbon equivalent abatement when reporting to the RGS procurement PAGs? Should the SBPM be modified to include $/ton CO2e and/or $/MMBtu value of CO2e abatement in scoring solicitation bids? If yes, how should its effect on SBPM scoring be determined?

B. Is there another approach the Commission should consider in evaluating biomethane in terms of its carbon impact cost efficiency and comparison with other resources?

2.18. Negative Carbon Intensity Environmental Benefits

D.22-02-025 OP 50 states the Utilities "shall maintain exclusive ownership of all environmental attributes from contracted biomethane sources." However, the benefit of these environmental attributes is likely limited to providing Cap-and-Trade compliance exemptions, which don't credit any benefit for

[27] Pub. Util. Section 650.1(a)(1).

carbon intensities below zero.[28] Without crediting negative carbon intensities, a significant value stream for biomethane producers and ratepayers is potentially lost.

The procured biomethane may also be incorrectly valued. As an example, the environmental attributes of extremely low carbon intensity biomethane from certain feedstocks, such as diverted organic waste, are being financially compensated at the same level as environmental attributes of biomethane with positive carbon intensities, such as from landfills. If the full environmental attributes of biomethane procured for the RGS were credited, the benefits of avoided GHG emissions to ratepayers would be more accurately represented in the price of the biomethane, with those additional benefits passed on to ratepayers in the form of environmental attributes or lower procurement prices.

This more complete valuation could potentially be accomplished by separating the gas from its attribute, or taking advantage of existing trading or incentive systems that give additional value to lower or negative carbon intensity biomethane, or some other approach as may be proposed by parties.

One possible approach could include separating the environmental attribute from the physical gas. If biomethane producers are able to keep the environmental attribute, they may be able to receive additional credit for lower carbon intensity biomethane in existing trading or incentive systems such as with RINs or RTCs. Modifying the targets in this program to procure just the physical gas while leaving the environmental attributes with the biomethane producers could increase biomethane production in California, grow the biomethane

[28] 17 CCR Sections 95852.1, 95852.1.1, and 95852.2.

market, and deliver RNG-derived gas to ratepayers at a lower price than for both the gas and the environmental attribute together.

Parties are directed to respond to the below question specific to negative carbon intensity environmental benefits:

A. How could more complete valuation of negative carbon intensities of procured biomethane be accomplished? Could the environmental benefit of negative carbon intensities be separated out from the C&T exemption to be traded or incentivized? How would this work within existing systems? What modifications could be made to existing systems to facilitate this more complete valuation?

B. Should the Commission consider modifying the RGS program to procure only the physical gas, with the environmental attribute staying with biomethane producer?

C. How could we ensure that the program continues to maximize, or even increases its focus on, avoided GHG emissions, and therefore benefits ratepayers?

D. How could it be ensured that any additional value attributed to biomethane through trading or incentive valuation would be transferred to ratepayers, either as environmental attributes or through lower procurement costs?

2.19. Need for RGS Program Modifications

Parties are directed to respond to the below question specific to possible RGS program modification benefits, based on the issues raised in this Ruling or based on insights parties may have gained from the market or through their program implementation:

A. Should the Commission consider making modifications to this program based on responses to this Ruling? What reasons support making program modifications at this time? How would any potential modifications be implemented?

2.20. Need For Additional Information

In addition to the questions posed to all parties to this ruling above, the Utilities shall refile their respective responses to the July 20, 2023 Ruling in this proceeding regarding biomethane procurement cost data estimates pursuant to the following direction:

- Sempra data must be separated into SoCalGas and SDG&E data so as to segregate anticipated impacts to each utility individually rather than in the aggregate.
- The data must include avoided Cap & Trade compliance costs and their impact on total above-market costs.
- The data must include $/ton CO_2 avoided emissions.
- Any other data modifications that are required, as identified through collaboration with Energy Division.

The Utilities must work with Energy Division staff to finalize a modified excel spreadsheet that will be consistent across all Utilities. The updated cost data estimates must be filed by July 19, 2024.

IT IS SO RULED.

Dated June 10, 2024, at San Francisco, California.

/s/ JOHN REYNOLDS
John Reynolds
Assigned Commissioner