STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

FILED
11/13/20
04:00 PM

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

November 13, 2020 **Agenda ID #18990**
Quasi-Legislative

TO PARTIES OF RECORD IN RULEMAKING 13-02-008:

This is the proposed decision of Commissioner Clifford Rechtschaffen. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 17, 2020 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

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

/s/ ANNE E. SIMON
Anne E. Simon
Chief Administrative Law Judge

AES:jnf
Attachment

Decision **PROPOSED DECISION OF COMMISSIONER RECHTSCHAFFEN**
(Mailed 11/13/2020)

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

DECISION ADOPTING THE STANDARD RENEWABLE GAS INTERCONNECTION AND OPERATING AGREEMENT

TABLE OF CONTENTS

DECISION ADOPTING THE STANDARD RENEWABLE GAS INTERCONNECTION AGREEMENT

Summary

This decision approves the Standard Renewable Gas Interconnection Agreement and related documents jointly proposed by Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company – collectively the "Joint Utilities" – on May 1, 2020, with modifications. The approved documents are set out in Appendices to this decision.

1. Procedural History

Rulemaking (R.) 13-02-008 was opened on February 13, 2013, to implement Assembly Bill (AB) 1900 (Gatto, 2012). The assigned Commissioner issued a scoping memo on May 2, 2013, (Initial Scoping Memo) to adopt rules to ensure that "each gas corporation provides non-discriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the safe delivery of gas."[1] The Initial Scoping Memo also states that "the cost associated with meeting the Commission-adopted standards and requirements will be addressed in this proceeding."[2]

[1] Initial Scoping Memo at 5.

[2] *Ibid* at 7.

On July 5, 2018, the Assigned Commissioner issued a scoping memo (Second Scoping Memo) for what was then the balance of this proceeding. It included the following order:

> In furtherance of Public Utilities Code Section 399.24, I direct Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company to jointly file a proposed standard biomethane interconnection tariff and proposed standard pro forma interconnection agreement forms within 90 days of this scoping memo.

On August 22, 2019, the assigned Commissioner extended the deadline for producing the proposed standard biomethane interconnection tariff to November 1, 2019, and directed that the tariff be designated as the Standard Renewable Gas Interconnection Tariff (SRGI Tariff) given the possibility that the Commission would later permit other renewable gases besides just biomethane to be included in pipeline gas. The August 22, 2019 Ruling established a separate deadline of February 1, 2020, to file a follow-on Standard Renewable Gas Interconnection Agreement (SRGI Agreement).

In response to a motion made by the Joint Utilities - Pacific Gas and Electric Company (PG&E), Southwest Gas Corporation (SWG), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E) - on October 18, 2019, the Assigned Commissioner extended the filing date for the SRGI Agreement from February 1, 2020 to May 1, 2020. On November 1, 2019, the Joint Utilities filed a proposed SRGI Tariff. On May 1, 2020, the Joint Utilities filed a proposed SRGI Agreement.[3]

[3] The Joint Utilities' proposed agreement is entitled the "Renewable Gas Interconnection and Operating Agreement" (RGIOA). In the interest of consistency between pro forma document titles, the CPUC renamed the RGIOA to Standard Renewable Gas Interconnection Agreement to

On May 18, 2020, Energy Division held a workshop on the SRGI Agreement. On May 28, 2020, comments on the SRGI Agreement were received from California Bioenergy LLC (CalBio), Dairy Cares, Maas Energy Works, Inc. (Maas), True North Renewable Energy (True North), and the Coalition for Renewable Natural Gas (CRNG). On June 3, 2020, the Joint Utilities and Dairy Cares each filed reply comments.

On August 27, 2020, the Commission issued Decision (D.) 20-08-035 adopting the SRGI Tariff. D.20-08-035 was subsequently corrected to address two clerical errors by D.20-09-042.

2. Discussion

With the adoption of D.20-08-035, we now address the last remaining topic still unresolved from the Second Scoping Memo: whether the California Public Utilities Commission (CPUC) should adopt the Joint Utilities' SRGI Agreement as proposed or with modifications. Additionally, we revisit rules governing the monetary incentive program established by D.15-06-029 to encourage the in-state production and distribution of biomethane, including funding level, eligibility, and compliance requirements.

---

align with the Standard Renewable Gas Interconnection Tariff. The attachments in the Joint Utilities' filing include the following documents: the Renewable Gas Interconnect Fact Sheet, Services Agreement and Attachments, Standard Renewable Gas Interconnection Agreement, Agreement to Transfer Ownership, and Data Access Agreement jointly proposed by Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company. Substantive modifications were made to the Standard Renewable Gas Interconnection Agreement and the Confidentiality Agreement within the Services Agreement and Attachments. The Renewable Gas Interconnect Fact Sheet, Agreement to Transfer Ownership, and Data Access Agreement are approved with minor ministerial modifications.

Finally, we consider whether to modify D.14-01-034, the CPUC decision that first implemented biomethane standards. More specifically, we consider whether to require the Joint Utilities to specify the lower and upper action levels for ammonia, biologicals, hydrogen, mercury, and siloxanes prior to filing an application pursuant to Ordering Paragraph (OP) 7 of D.14-01-034 for the CPUC to review and update biomethane gas specifications. We also clarify certain reporting requirements to better facilitate future updates to biomethane standards.

2.1. Modifications to the SRGI Agreement

2.1.1. Amount of "Performance Assurance" Required from Biomethane Producers

Section 16(a) of the proposed SRGI Agreement reads as follows:

> Performance Assurance Requirement. Interconnector agrees to deliver to Utility Performance Assurance in the form of a cash deposit or Letter of Credit to secure its obligations under this Agreement in an amount equivalent to one million dollars ($1,000,000). The Performance Assurance must be delivered to Utility within five (5) Business Days following the date that Release to Operations occurs.[4]

PG&E proposed the one million dollar figure in the SRGI Agreement, with which SDG&E, SoCalGas, and SWG agreed. However, SDG&E and SoCalGas currently offer a lower performance assurance to biomethane producers, while SWG has no such requirement currently in place.

In D.15-06-029, the Commission ruled that the cost burden of complying with AB 1900 (Gatto, 2012), as adopted in D.14-01-034 should be borne entirely by Interconnectors producing renewable natural gas (RNG) because the intent of the

[4] A "performance assurance" is a guarantee to secure obligations under the agreement.

Legislature was to guarantee to all methane suppliers, regardless of source, nondiscriminatory open access to the utilities' gas pipeline systems.[5] As such, in order to ensure nondiscriminatory open access, the performance assurance burden on an RNG producer should be the same as the performance assurance burden on a natural gas (*i.e.,* fossil fuel) producer. Given the larger size of fossil fuel producers vis-à-vis RNG producers, an across-the-board one million dollar performance assurance may effectively erode nondiscriminatory open access for RNG producers.

Several parties express concern with the Joint Utilities' proposed one million dollar performance assurance. California Bioenergy LLC (CalBio),[6] Dairy Cares,[7] Maas,[8] and Coalition for Renewable Natural Gas (CRNG)[9] all consider the one million dollar performance assurance to be overly burdensome. In the interest of promoting RNG production and interconnection, CalBio, Maas, and CRNG suggest that the CPUC instead adopt the lower performance assurance currently used by both SoCalGas and SDG&E.

---

[5] "Since the Legislature intended in AB 1900 that there be nondiscriminatory open access to the utilities' gas pipeline systems, and because the Legislature intended that the Commission adopt biomethane standards to ensure the protection of human health, and pipeline and pipeline facility integrity and safety, we conclude that the cost of complying with D.14-01-034 is to be borne by the biomethane producers." D.15-06-029 at 27.

[6] California Bioenergy LLC's Comments on the Joint Utilities Renewable Gas Interconnection Rule of Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company and San Diego Gas and Electric Company, November 21, 2019, at 4.

[7] Opening Comments of Dairy Cares on the Joint Utilities Renewable Gas Interconnection Rule, November 21, 2019, at 5-6.

[8] Maas Energy Works, Inc. Comments on Joint Utilities Renewable Gas Interconnection Rule of Pacific Gas and electric Company, Southwest Gas Corporation, Southern California Gas company and San Diego Gas & Electric Company, November 21, 2019, at 4-5.

[9] Renewable Natural Gas Coalition's Comments on Proposed Decision November 21, 2019, at 4.

We agree with CalBio, Dairy Cares, Maas, and CRNG that the performance assurance requirement delineated in SoCalGas's California Producer Operational Balancing Agreement (CPOBA)[10] represents a better approach to ensuring nondiscriminatory open access for RNG producers and is more in line with the intent of the Legislature to promote the in-state production and use of RNG. SoCalGas requires Interconnectors to its pipeline network provide a performance assurance – called a "security deposit" in the CPOBA – in the form of either a cash deposit or a letter of credit only if it determines, after a thorough review, that a producer is not creditworthy.[11] The performance assurance required is not a flat amount, but is determined by a formula:

> …the Interconnector's Interconnect Capacity multiplied by 40 days, and then multiplied by the average of the Average Daily Index – SoCal Border Average as reported by [Natural Gas Intelligence] (or its legal successor) for each day of the immediately preceding calendar month. If, for any reason, [Natural Gas Intelligence] (or its legal successor) ceases to be available, the price index will be based on another generally accepted available publication selected by SoCalGas in its sole discretion.[12]

Under Public Utilities (Pub. Util.) Code Section 399.24(a), the Commission is required to adopt policies and programs that promote the in-state production and distribution of biomethane. To meet this requirement, we should take all reasonable steps to lower the cost of producing and distributing in-state RNG.

---

[10] A specimen CPOBA may be found here: https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/CPOBA.pdf.

[11] ."Any Interconnector which is delivering Gas into the SoCalGas system under an existing access agreement, as of August 23, 2007, the effective date of D.07-08-029, shall be deemed creditworthy unless the Interconnector shows a pattern of material past due payments or the Interconnector's financial condition has materially degraded." CPOBA, Section 8.8.1.

[12] CPOBA, Section 8.8.5.

For that reason, we modify the SRGI Agreement by removing the proposed one million dollar performance assurance and replacing it with a provision that permits, but does not require, a utility to obtain a performance assurance from an Interconnector that conforms with the formula in SoCalGas's CPOBA. We believe that conformance with the performance assurance requirement in SoCalGas's CPOBA will significantly lower the development cost of in-state RNG while providing adequate performance assurance for each of the Joint Utilities.

For contracts that are executed but not yet operational, the Commission directs the Joint Utilities to give Interconnectors the option of either keeping the existing contract terms or executing a contract amendment that is consistent with revisions adopted in this decision. Any amended contracts shall be filed as Tier 2 Advice Letters if they contain no other changes. If they contain other changes, the amended contracts shall be filed as Tier 3 Advice Letters.

2.1.2. Disclosure of Non-Sensitive Information

The draft Confidentiality Agreement that accompanies the draft SRGI Agreement[13] broadly limits disclosure of information about any biomethane interconnection project and, with minor exceptions, places control of project information solely in the hands of the utility. More specifically, the Confidentiality Agreement, as proposed, protects "Proprietary Information," defined as "any data, information, trade secrets or "know-how" that is proprietary to a Party or security sensitive, and not known to the party receiving

[13] The Confidentiality Agreement was inadvertently included in party comments submitted August 17, 2020. The Commission amends the SRGI Agreement to include the Confidentiality Agreement on behalf of the Joint Utilities to correct the filing error.

it or the general public…." As such, parties to a contract may be restricted in their ability to disclose matters of public concern.

We find that the Confidentiality Agreement, as drafted by the Joint Utilities, is overly broad. The Confidentiality Agreement protects the legitimate confidentiality interests of the utility, but it also restricts the dissemination of useful information whose public disclosure is not harmful to the utility. Accordingly, we modify the draft Confidentiality Agreement to include a provision authorizing the Interconnector to disclose information related to cost, required equipment, design, timing, and other information related to the interconnection unless such disclosure includes trade secrets and/or critical infrastructure information, or poses a serious safety risk.

2.1.3. Continuous Flow Requirement

The proposed SRGI Agreement's "Continuous Flow" requirement in Section 5(e) conflicts with the "Forecasted Operating Profile" requirement in the accompanying Fact Sheet document. Section 5(e) states, "Interconnector shall deliver Renewable Gas to the Interconnection Point Continuously and without interruption of supply unless continuous flow is interrupted by Utility for operational reasons or by Interconnector for scheduled maintenance to Interconnector's Facilities." This requirement can be interpreted to imply that continuous flow must be delivered at all hours of the day, which may not be possible due to the intermittent nature of RNG production. In contrast, the Fact Sheet gives discrete time frames for continuous flow to account for intermittency.

We find that the clause should be modified in accordance with party comments. CalBio states that "[t]he express terms in the Fact Sheet directly contradict the continuous flow mandate" in the SRGI Agreement.[14] Dairy Cares states that "gas production of dairy digesters can vary greatly due to seasonal temperature changes. Further, pipeline interconnected dairy digester projects often only flow during certain hours during of the day. The continuous flow requirement may pose a significant challenge for many projects due to seasonality and a variety of other supply variables."[15] True North states that "[n]umerous customer gas meters only flow intermittently, and this should have no adverse impact unless the Utility can demonstrate proof."[16] Additionally, the Joint Utilities "agree that the contractual continuous requirement can be removed."[17] The Joint Utilities propose an additional caveat that "if gas deliveries are made discontinuously and cause receipt point facilities to be shut-in and require a manual restart by Utility maintenance personnel, the Joint Utilities should not be at risk and cannot be held liable for any period of time that the Utility cannot receive Interconnector's gas."[18] Yet, under the agreement in the Fact Sheet, the time of delivery is explicitly discontinuous, therefore the caveat does not comply with the Utility's Fact Sheet. The modification will promote coherence and consistency between the two documents.

---

[14] CalBio Comments on Assigned Commissioner Scoping Memo and Ruling July 26, 2018, at 4.

[15] Dairy Cares Comments on Assigned Commissioner Scoping Memo and Ruling July 26, 2018, at 4.

[16] True North Comments on Assigned Commissioner Scoping Memo and Ruling July 26, 2018, at 5.

[17] Joint Utilities Comments on Assigned Commissioner Scoping Memo and Ruling July 26, 2018, at 10.

[18] *Ibid* at 8.

2.2. Monetary Incentive Program Rules

2.2.1. Increasing Funding Level for Biomethane Projects

Pub. Util. Code Section 784.2, amended under AB 3187 (Grayson, 2018), directs the CPUC to "consider options to further the goals of section 399.24, including consideration of whether to allow recovery in rates of the costs of investments" to fulfill the functions stipulated in subdivisions (a), (b), and (c) of Pub. Util. Code Section 784.2. In D.19-12-009, the CPUC declined to consider the issue of recovery in rates prior to evaluating results from projects that completed interconnection pursuant to the monetary incentive program for biomethane projects approved pursuant to D.15-06-029. Without interconnection of additional biomethane projects, the Commission remains unable to make any of the findings specified in Pub. Util. Code Section 784.2 regarding recovery of interconnection costs in rates. Instead, we address the question of whether to further the goals of Pub. Util. Code Section 399.24 by authorizing an additional $40 million in the monetary incentive program.

D.15-06-029 created a $40 million monetary incentive program "to encourage potential biomethane producers to build and operate biomethane projects within California that interconnect with the utilities" in accordance with AB 1900 (Gatto, 2012). This monetary incentive program was subsequently codified by AB 2313 (Williams, 2016), which modified and extended the program without specifying a funding cap or a particular funding source. The funding made available for biomethane projects by the Joint Utilities is to be recovered from their ratepayers, with incentives for projects in a particular gas utility's service territory funded by the ratepayers of that gas utility. The $40 million approved by the Commission for the monetary incentive program is currently fully subscribed and there is a wait list for an additional $38.5 million worth of project funding.[19]

Parties began requesting an increase to the $40 million biomethane monetary incentive in response to the July 5, 2018 Scoping Memo, which noted the direction to the CPUC set forth in Pub. Util. Code Section 784.2 and asked whether the CPUC should extend the monetary incentive program beyond 2021. Gas Technology Institute, DTE Biomass Energy, CR&R Environmental Services (CR&R), Climate Resolve, California Association of Sanitation Agencies (CASA), and Bioenergy Association of California (BAC) each address the importance of increasing incentives to align with the state's Short-Lived Climate Pollutant (SLCP)[20] and air quality goals, as required by Senate Bill (SB) 1383 (Lara, 2016). Gas Technology Institute recommends that the CPUC "consider significantly increasing this incentive program."[21] DTE Biomass Energy "strongly advises the Commission to increase the monetary incentive available for pipeline interconnection in California."[22] CR&R states that "[g]iven how far behind the gas sector is in reducing its emissions – compared to the electricity sector – and

---

[19] The waitlist is $38.5 million worth of project funding as of November 5, 2018, and is subject to change in accordance with future reservations.

[20] According to CARB's 2017 Short-Lived Climate Pollutant Reduction Strategy, SLCPs are "powerful climate forcers and harmful air pollutants that have an outsized impact on climate change in the near term, compared to longer-lived GHGs, such as carbon dioxide (CO2). SLCPs are estimated to be responsible for about 40 percent of current net climate forcing. Action to reduce these powerful "super pollutants" today will provide immediate benefits as the effects of our policies to reduce long-lived GHGs further unfold."

[21] Gas Technology Institute Comments on Assigned Commissioner Scoping Memo and Ruling July 26, 2018, at 9.

[22] DTE Biomass Energy Comments on Assigned Commissioner Scoping Memo and Ruling July 26, 2018, at 6.

the urgency of reducing [short-lived climate pollutant] SLCP emissions, the Commission should significantly increase this incentive program."[23] CalBio argues that because "increasing pipeline biogas is the lowest carbon, most beneficial way to reduce emissions from the gas sector. CalBio urges the Commission to revise the pipeline biogas interconnection incentive in the following ways: a. The $40 million cap should be increased to $400 million or should be removed altogether until the state has met the SLCP requirements of SB 1383."[24]

Various parties including CalBio, BAC and GTI specifically ask the Commission to use funds from the gas cap-and-trade allowance[25] to increase funding for biomethane projects. The comments point out that the Commission may invest such funds in programs that reduce GHG, provided only that the programs meet applicable California Air Resources Board (CARB) regulations. CARB regulations establish three distinct uses for gas utility cap-and-trade allowance proceeds. The second use, established in 17 CCR Section 95893(d)(3)(B), is composed of four requirements. To qualify for the use of gas cap-and-trade allowance funds, a proposed biomethane capture project must:

(a) reduce emissions of uncombusted natural gas;

(b) not be mandated by any federal, state, or local health and safety requirements;

[23] CR&R Incorporated Comments on Assigned Commissioner Scoping Memo and Ruling July 27, 2018, at 7

[24] California Bioenergy LLC's comments on Assigned Commissioner Scoping Memo and Ruling July 27, 2018, at 7-8

[25] Gas cap-and-trade allowance funds are proceeds that the Joint Utilities receive after consigning to auction the cap-and-trade allowances that the CARB allocates to them annually on behalf of their ratepayers.

(c) not be mandated by Senate Bill 1371 (Leno, 2014); and

(d) not be mandated by the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (17 CCR Sections 95665-95677).

The proposed California biomethane capture projects meet all four requirements.

(a) They displace fossil natural gas, reducing unit-for-unit the GHG emissions that would otherwise have occurred.

(b) They are not mandated by any federal, state, or local requirements for the specified purpose of promoting health and safety.[26]

(c) They are not mandated by SB 1371 (Leno, 2014).

(d) They are not mandated by the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities (17 CCR Sections 95665-95677).

In D.18-03-017 the Commission asserted its broad authority to invest gas utility cap-and-trade allowance proceeds in Commission-sponsored programs designed to reduce greenhouse gas (GHG) emissions:

The Commission concludes, consistent with the interpretation of the California Supreme Court, that § 453.5 does not apply to the distribution of GHG allowance proceeds to the retail ratepayers of natural gas utilities. GHG allowance proceeds are not rate refunds under the code section. Therefore, the Commission is bound only by the [C]ARB regulation in determining the appropriate distribution of GHG allowance proceeds. There are no other express

[26] Pub. Util. Code Section 399.24 states that the purpose of promoting the in-state production and distribution of biomethane is to "meet the energy and transportation needs of the state."

restrictions in the Public Utilities Code on the Commission's authority to determine how to distribute GHG allowance proceeds.[27]

D.18-03-017 also required that 100 percent of gas utility cap-and-trade allowance proceeds be returned to residential gas customers in the form of a single annual climate credit (California Climate Credit), *subject to the Commission's authority to use some or all of such proceeds for GHG reduction or other CARB-approved programs.*

In addition to specifying the uses to which gas cap-and-trade allowance proceeds may be put, CARB regulations also require that the percentage of consigned allowances for gas utilities start at 25 percent in 2015 and increase five percent each year until hitting 100 percent in 2030. Absent additional diversion of allowance proceeds for programmatic purposes or drastic changes in natural gas consumption, the amount of allowance proceeds will increase each year for the next 10 years.

After weighing the benefit of increased biomethane capture and use against the modest reduction in the California Climate Credit necessary to fully fund all existing biomethane projects, including those on the waitlist, we find it appropriate to provide an additional $40 million in funding from cap-and-trade allowance proceeds for the monetary incentive program to fund the biomethane projects that are currently on the wait list, bringing total funding to $80 million. The additional funding would enable all or nearly all[28] of the currently waitlisted

[27] D.18-03-017 at 24.

[28] While $40 million in additional funding is more than enough to cover the $38.5 million in project funding requests currently on the wait list, cap-and-trade allowance proceeds are reserved solely for the service territories from which those proceeds were derived. As such, if a particular gas utility has more demand for project funding from the projects represented on the wait list than its share of an additional $40 million in funding, not all projects currently on the

biomethane projects to receive a monetary incentive while still preserving the balance of allowance proceeds for the California Climate Credit. This is an appropriate use of gas utility cap-and-trade allowance proceeds since every unit of biomethane injected into gas utility pipelines displaces a unit of fossil fuel that would otherwise disperse GHG emissions into the atmosphere. All the biomethane projects currently on the wait list emit methane, a potent SLCP,[29] directly into the atmosphere. Reducing methane emissions is the primary goal of the biomethane monetary incentive program and retail natural gas ratepayers are the primary beneficiaries, as they will directly reap the benefits of cleaner air and reduced GHG emissions.

CARB regulations specify that ap-and-trade allowance proceeds must be proportionally directed to the gas utility service territories where the funds are derived.[30] In compliance with this requirement, the collective allocation of the additional $40 million in additional incentive spending shall be split across each of the Joint Utilities' service territories consistent with each gas utility's respective

wait list in that particular gas utility's service territory will necessarily be able to receive funding. CARB's funding regulations are discussed in greater detail below.

[29] According to CARB's 2017 Short-Lived Climate Pollutant Reduction Strategy, SLCPs "are powerful climate forcers and harmful air pollutants that have an outsized impact on climate change in the near term, compared to longer-lived GHGs, such as carbon dioxide (CO2). SLCPs are estimated to be responsible for about 40 percent of current net climate forcing. Action to reduce these powerful "super pollutants" today will provide immediate benefits as the effects of our policies to reduce long-lived GHGs further unfold.

[30] See Title 17 of the California Code of Regulations Section 95893(d)(3): "Allowance value, including any allocated allowance auction proceeds, obtained by a natural gas supplier must be used for the primary benefit of retail natural gas ratepayers of each natural gas supplier, consistent with the goals of Assembly Bill 32, and may not be used for the benefit of entities or persons other than such ratepayers."

percentage of their combined CARB allocation of cap-and-trade allowances, which are as follows:

- SoCalGas: $19,704,000 (49.26 percent of $40 million)
- PG&E: $16,936,000 (42.34 percent of $40 million)
- SDG&E: $2,708,000 (6.77 percent of $40 million)
- SWG: $652,000 (1.63 percent of $40 million)

CARB regulations also require that any spending of cap-and-trade allowance proceeds within a specific gas utility's service territory must be attributed to that gas utility for the purposes of reporting to CARB[31] and that any unspent funds shall be returned to ratepayers on or before 10 years from the date of collection.[32]

In order to provide the additional $40 million to the monetary incentive program with minimized impact to the California Climate Credit, we direct the Joint Utilities to set aside their respective shares of the $40 million in collective installments of $5 million quarterly over the course of two years, starting with the first cap-and-trade allowance auction in 2021.[33] Providing the additional $40 million for the monetary incentive program in this way would preserve entire 2021 California Climate Credit and reduce each of the 2022 and 2023 California Climate Credits by $20 million.

---

[31] 17 CCR Section 95893(e).

[32] 17 CCR Section 95893(d)(8).

[33] CARB holds quarterly auctions in February, May, August, and November. Each of the Joint Utilities is required to put up for auction its consigned allowances within the designated calendar year. Within a given year, however, each of the Joint Utilities can decide at its discretion how to distribute its allowances among the four auctions.

Each of the Joint Utilities files an annual natural gas true-up advice letter that sets natural gas transportation rates and establishes the use of allocated allowance proceeds for the coming year, using templates originally set in D.15-10-032 and modified in D.20-03-027. For the purpose of calculating the 2022 and 2023 California Climate Credits, the Joint Utilities' advice letter filings shall modify the table format established by D.15-10-032 (*i.e.,* Table C of Appendix A of that decision) to include below line 9b a new line numbered 9c and titled "RNG Incentive Costs." This line shall record each gas utility's share of the $40 million in funding, as established by this decision. Line 10 of Table C of Appendix A of D.15-10-032 shall also be modified to equal the Subtotal Allowance Proceeds minus Outreach and Admin Expenses minus SB 1477 Compliance Costs minus the RNG Incentive Costs. In order to reflect this change, the Joint Utilities shall, for the two relevant advice letter filings, further modify the template for Table C by changing the description of Line 10 of Table C of Appendix A of D.15-10-032 to "Net GHG Proceeds Available for Customer Returns ($) (Line 8 + Line 9 + Line 9b + Line 9c)."

Each of the Joint Utilities shall, within 15 days of the approval of this decision, file a Tier 1 advice letter with Energy Division formalizing a new balancing account to collect and track their respective share of the $40 million as those funds become available moving forward. Each of the Joint Utilities shall set aside its respective share of quarterly funding starting no later than March 1, 2021, and ending December 1, 2022. A report must be submitted by each of the Joint Utilities to Energy Division no later than one month after each quarterly set-aside, starting April 1, 2021, providing its balance of Cap-and-Trade allowance proceeds and denoting all projects that received incentive funding from those allowance proceeds, if any. No allowance proceeds shall be expended until the projects entitled to the first $40 million approved pursuant to D.15-06-029 are funded. However, if all the projects in a particular gas utility's service territory to be funded using the first $40 million are funded, but those in other gas utility service territories are not, the gas utility whose projects are all funded may begin funding projects on the wait list using allowance proceeds.

2.2.2. Making Incentives Available to Interconnectors Using Third-Party Pipelines

Monetary incentives are currently available only to projects that interconnect directly to infrastructure owned by the Joint Utilities. AB 2313 (Williams, 2016) extended the monetary incentive program through December 31, 2026. The legislation also mandated that the Commission find ways to increase biomethane use through interconnection with utility infrastructure.

Biomethane producers who inject gas into utility systems via third-party-owned pipelines that are already interconnected to utility-owned infrastructure do not presently qualify for incentives. Various parties to this proceeding, including CRNG[34] and SeaHold,[35] have pointed out that using already built pipelines to interconnect and transport biomethane is a cost-effective use of infrastructure that can deliver biomethane to a gas utility without necessarily constructing new facilities. Because RNG and fossil gas both must ultimately meet pipeline quality injection standards in order to interconnect, delivering RNG via third-party pipelines that already transport fossil gas can,

---

[34] CRNG Comments November 21, 2019, supra, at 4.

[35] Seahold LLC Comments on the Joint Utilities Renewable Gas Interconnection Rule of Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company and San Diego Gas and Electric Company, November 21, 2019, at 5.

without compromising safety, dramatically lower the cost of delivering RNG to the pipeline distribution system rather than having to build lengthy new pipes to access a utility-owned pipeline system potentially a substantial distance away. The suggestion to address this issue was first made in comments in response to the July 5, 2018 Scoping Memo. It was reiterated by several parties in the November 1, 2019 workshop. The Joint Utilities also support the concept in their comments on the SRGI Tariff.

We conclude that extending eligibility for financial incentives to biomethane producers who interconnect with utility infrastructure via third-party pipelines is a desirable modification of the program.

2.2.3. Clarifying Compliance Requirements

Prior decisions adopted in this rulemaking established several compliance requirements relating to biomethane projects that receive funds from the monetary incentive program. Those compliance requirements include, but are not limited to, the following:

- The project flow requirement specified in OP 2.c of D.15-06-029.
- The cost tracking requirement specified in OP 2.d of D.15-06-029.
- The notification requirement specified in OP 2.e of D.15-06-029; and
- The reporting requirement specified in OP 2.h of D.15-06-029 and subsequently modified by OP 20 of D.19-12-009.

We clarify here that all biomethane projects that receive funds from the monetary incentive program are subject to the same compliance requirements, regardless of funding source. We further clarify that the additional incentive funds authorized in this decision shall be awarded pursuant to the waiting list procedures approved in D.19-12-009.

2.3. Additional Considerations

2.3.1. Specifying Lower and Upper Action Levels for Ammonia, Biologicals, Hydrogen, Mercury, and Siloxanes

D.14-01-034 adopted biomethane standards pursuant to the process established by AB 1900 (Gatto, 2012). Health and Safety Code Section 25421 specifies that creating and updating biomethane standards starts first with the Office of Environmental Health Hazard Assessment (OEHHA). OEHHA must compile a list of constituents of concern that could pose risks to human health and are found in biomethane at concentrations that significantly exceed the concentrations of those constituents in fossil natural gas. OEHHA must then determine health protective levels for the list of constituents of concern identified. OEHHA's findings are compiled into a report that is then to be used by CARB to identify realistic exposure scenarios and the health risks associated with those exposure scenarios. CARB must then determine the appropriate concentrations of constituents of concern and identify reasonable and prudent monitoring, testing, reporting, and recordkeeping requirements – separately for each source of biomethane – that are sufficient to ensure compliance with health protective standards.

Pursuant to OP 7 of D.14-01-034, the Joint Utilities are required to file an application at the CPUC to formally update biomethane standards after CARB publishes updated guidance. Alternatively, per OP 8 of the same decision, either OEHHA or CARB can send a letter to the CPUC requesting updates to the biomethane standards if action is deemed necessary prior to the five-year mark. OP 9 of D.14-01-034 requires the Joint Utilities to specify the lower and upper action levels[36] for ammonia, biologicals, hydrogen, mercury, and siloxanes as part of the process of updating biomethane standards for the first time. Because CARB never published updated guidance, on December 10, 2018, the Commission's Executive Director granted Joint Utilities a waiver of these obligations.

OEHHA completed its first update report on January 7, 2020, but CARB has not yet acted in response to that report. Until CARB acts, Joint Utilities have no obligation to file the application mandated by D. 14-01-034 to specify the lower and upper action levels for ammonia, biologicals, hydrogen, mercury, and siloxanes. As a result, developers of biomethane production facilities do not know what standards they will be held to and potential risks to human health and pipeline integrity are unmitigated.

We find it prudent to require Joint Utilities to specify lower and upper action levels for ammonia, biologicals, hydrogen, mercury, and siloxanes as soon as practicable rather than waiting on further action by CARB. Ammonia, biologicals, hydrogen, mercury, and siloxanes were not constituents of concern originally identified by CARB in 2013. They were included in the list of constituents of concern adopted by the CPUC at the request of Joint Utilities. We conclude that Joint Utilities need not wait for updated guidance from CARB before making the necessary action level specifications. We will order them to

[36] Lower and upper action levels are defined in the Standard Renewable Gas Interconnection Tariff. Lower Action Level is "[t]he concentration or measured value of a Constituent, used to screen Renewable Gas during the initial gas quality review and ongoing periodic testing, requiring a shut-off of Renewable Gas supply if exceeded three times in a 12-month period." Upper Action Level is "[t]he concentration or measured value of a Constituent requiring an immediate shut-off of Renewable Gas supply." D.14-01-034, *supra* note **Error! Bookmark not defined.**.

make the required specifications in a Tier 1 advice letter to be submitted to the CPUC no later than three months from the date of adoption of this decision.

2.3.2. Reporting Requirements

Current CPUC rules adopted in this proceeding require the Joint Utilities to report annually on various aspects of biomethane safety. OP 2 of D.14-01-034 states:

> As clarified in this decision, we adopt the monitoring, testing, reporting, and recordkeeping protocols that were recommended for adoption in the May 15, 2013 "Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline.

The referenced report, issued jointly by CARB and OEHHA, recommends that the Joint Utilities provide the CPUC with the following information:

- All test data (concentrations of constituents of concern and identification of associated test methods) received during the report period;
- Annual biomethane production rate;
- Monitoring parameters used to ensure that the upgrading system is operating effectively; and
- Dates of any shutoff events, the reason for the shutoff, the actions taken to resume injection into the pipeline, and the start of re-injection into the pipeline (if applicable).[37]

Neither the May 15, 2013 report nor D.14-01-034 specify a date by which the Joint Utilities must submit their annual report. While report filings are generally made in January, submittal dates vary, and reports have sometimes not been submitted until mid-February. Additionally, the Joint Utilities are only required

[37] OEHHA Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline May 15, 2013, at 71-72.

to file their annual reports with the CPUC, leaving the CPUC as the information-sharing intermediary between the Joint Utilities and both CARB and OEHHA.

To ensure consistency across the Joint Utilities, we clarify that the annual reporting obligation shall have a date certain of January 15 in order to comport with the separate reporting obligation first established by OP 2.h of D.15-06-029 regarding biomethane projects that interconnect with the Joint Utilities after receiving a monetary incentive. Additionally, to expedite information-sharing, we require the Joint Utilities to send their annual reports to both CARB and OEHHA at the same time they are sent to the CPUC. The annual report filings shall not be redacted.

3. Comments on Proposed Decision

The proposed decision of the Commissioner in this matter was mailed to the parties in accordance with Pub. Util. Code section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by _________ on __________. Reply comments were filed by _______ on _______.

4. Assignment of Proceeding

Clifford Rechtschaffen is the Assigned Commissioner for this proceeding and Karl J. Bemesderfer is the Assigned Administrative Law Judge.

Findings of Fact

1. A standard agreement between the Joint Utilities and biomethane developers will allow for uniform and consistent regulation of renewable gas in utility-owned pipelines.

2. Lower initial costs for construction promote renewable gas project development.

3. SoCalGas currently uses a creditworthiness test to establish a performance assurance that is less burdensome than the proposed SRGI Agreement performance assurance.

4. The draft NDA that accompanied the proposed SRGI Agreement broadly limits disclosure of information about any biomethane interconnection project and, with minor exceptions, places control of project information solely in the hands of the utility.

5. Expanding the amount of monetary incentive available to renewable gas developers will encourage and facilitate the production of renewable gas within California.

6. The cost burden for complying with the health and safety concerns expressed in Assembly Bill (AB) 1900 (Gatto, 2012), and as adopted in Decision (D.) 14-01-034 and D.20-08-035 falls entirely on the Interconnector.

7. Reducing atmospheric methane emissions is the primary goal of the biomethane monetary incentive program and retail natural gas ratepayers are the primary beneficiaries.

8. The Scoping Memo dated July 5, 2018, directs the Joint Utilities to develop standardized interconnection forms for biomethane projects.

9. The May 15, 2013 report composed jointly by CARB and OEHHA titled "Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline" did not identify ammonia, biologicals, hydrogen, mercury, and siloxanes as constituents of concern.

10. Ordering Paragraph 2 of D.14-01-034 imposed monitoring, testing, reporting, and recordkeeping protocols that require the Joint Utilities to file an

annual report that includes information regarding various aspects of biomethane safety.

Conclusions of Law

1. Pub. Util. Code Section 399.24 provides for the adoption of policies and programs that promote the production and distribution of in-state biomethane.

2. AB 3187 (Grayson, 2018) and Pub. Util. Code Section 784.2 direct the Commission to consider options to further the goals of Pub. Util. Code Section 399.24, including consideration of whether to allow recovery in rates of the costs of interconnecting renewable natural gas projects.

3. All methane suppliers, regardless of source, are entitled to nondiscriminatory open access to the Joint Utilities' gas pipeline systems.

4. The purpose of an NDA is to protect the legitimate confidentiality interests of the utility without restricting the dissemination of useful information whose public disclosure is not harmful to the utility.

5. Pub. Util. Code Section 784.2 does not cap the amount of monetary incentive available to biomethane developers.

6. All biomethane projects that receive funds from the monetary incentive program are subject to the same compliance requirements, regardless of funding source.

7. SB 1477 (Stern, 2018) requires cap-and-trade allowance proceeds to be used for greenhouse gas reduction programs.

8. D.18-03-017 gives the Commission discretion to apply cap-and-trade allowances to GHG reduction programs, subject only to the requirement that such programs meet CARB guidelines.

9. The Commission may use cap-and-trade allowance proceeds to increase the biomethane interconnection monetary incentives.

10. AB 1900 (Gatto, 2012), Health and Safety Code Section 25421, and Ordering Paragraph 9 of D.14-01-034 require CARB and OEHHA to provide guidance on biomethane specifications and constituents of concern that must be updated every five years.

11. D.14-01-034 does not specify a date by which the Joint Utilities must file their annual reports on various aspects of biomethane safety.

12. D.14-01-034 does not require the Joint Utilities to submit their annual reports directly to CARB or OEHHA.

O R D E R

IT IS ORDERED that:

1. The Standard Renewable Gas Interconnection Agreement and the Confidentiality Agreement within the Services Agreement and Attachments, jointly proposed by Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company, as modified by this decision, are approved. The attachments to this Agreement (the Renewable Gas Interconnect Fact Sheet, Agreement to Transfer Ownership, and Data Access Agreement) are approved with minor ministerial modifications.

2. Within 30 days of the effective date of this decision, Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company shall each file a Tier 2 Advice Letter adopting the Standard Renewable Gas Interconnection Agreement.

3. An additional $40 million of cap-and-trade allowance proceeds shall be added to the biomethane monetary incentive program, with $5 million installments collected in proportion to Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company's respective percentage share of allocated proceeds beginning March 1, 2021, and ending December 1, 2022.

4. For the purpose of calculating the 2022 and 2023 California Climate Credits, Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company, in their annual natural gas true-up advice letter filings, shall modify the table format established by Decision 15-10-032 (*i.e.,* Table C of Appendix A of that decision) to include below line 9b a new line numbered 9c and titled "RNG Incentive Costs." This line shall record each gas utility's share of the $40 million in funding, as established by this decision. Line 10 of Table C of Appendix A of Decision 15-10-032 shall also be modified to equal the Subtotal Allowance Proceeds minus Outreach and Admin Expenses minus Senate Bill 1477 Compliance Costs minus the RNG Incentive Costs. In order to reflect this change, the Joint Utilities shall, for the two relevant advice letter filings, further modify the template for Table C by changing the description of Line 10 of Table C of Appendix A of D.15-10-032 to "Net GHG Proceeds Available for Customer Returns ($) (Line 8 + Line 9 + Line 9b + Line 9c)."

5. Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company shall each, within 15 days of the approval of this decision, file a Tier 1 advice letter with Energy Division formalizing a new balancing account to collect and track their

respective share of the additional $40 million to be made available for the monetary incentive program from their cap-and-trade allowance proceeds as those funds become available moving forward.

6. Each of Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company shall submit a report to Energy Division no later than one month after each quarterly set-aside, starting April 1, 2021, providing its balance of cap-and-trade allowance proceeds and identifying all projects that received incentive funding from those allowance proceeds.

7. No allowance proceeds shall be expended until the projects entitled to the first $40 million approved pursuant to Decision 15-06-029 are funded. However, if all the projects in a particular gas utility's service territory to be funded using the first $40 million are funded, but those in other gas utility service territories are not, the gas utility whose projects are all funded may begin funding projects on the wait list using allowance proceeds.

8. The biomethane monetary incentive funds shall be proportionally allocated to the service territories from which the funds are derived.

9. The additional incentive funds authorized in this decision shall be awarded pursuant to the waiting list procedures approved in Decision 19-12-009.

10. Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company shall provide upper and lower action level specifications for ammonia, biologicals, hydrogen, mercury, and siloxanes in a joint filing to be submitted to the Commission no later than three months from the date of adoption of this decision.

11. Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company shall file their annual reports required pursuant to Ordering Paragraph 2 of Decision 14-01-034 no later than January 15 of each year. Those reports shall be sent to California Air Resources Board and Office of Environmental Health Hazard Assessment at the same time they are sent to the Commission. The annual report filings shall not be redacted.

12. This proceeding shall remain open.

This decision is effective today.

Dated ____________________, 2020 at San Francisco, CA

ATTACHMENT A

Renewable Gas Interconnect Fact Sheet

ATTACHMENT B

Services Agreement and Attachments

ATTACHMENT C

Renewable Gas Interconnection and Operating Agreement

ATTACHMENT D

Agreement to Transfer Ownership

ATTACHMENT E

Data Access Agreement