STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
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TO PARTIES OF RECORD IN RULEMAKING 13-02-008:

This is the proposed decision of Commissioner 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 February 10, 2022 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

COM/CR6/jnf **PROPOSED DECISION** **Agenda ID #20241**
Quasi-Legislative

Decision **PROPOSED DECISION OF COMMISSIONER RECHTSCHAFFEN**
(Mailed 1/3/2022)

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 IMPLEMENTING SENATE BILL 1440 BIOMETHANE PROCUREMENT PROGRAM

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DECISION IMPLEMENTING SENATE BILL 1440 BIOMETHANE PROCUREMENT PROGRAM

Summary

We implement Senate Bill 1440 by setting biomethane (renewable natural gas (RNG) and/or bio-synthetic natural gas (bio-SNG))[1] procurement targets to reduce short-lived climate pollutant emissions. We adopt provisions to achieve additional co-benefits and timetables for each investor-owned utility providing gas service in California. We adopt related measures to ensure that all actions taken pursuant to this decision are consistent with applicable state and federal laws.

1. Procedural History

On November 21, 2019, the California Public Utilities Commission (CPUC or Commission) initiated Phase 4 of Rulemaking (R.) 13-02-008 to implement Senate Bill (SB) 1440 (Hueso, 2018), which requires the CPUC to consider adopting biomethane procurement targets or goals for each investor-owned utility (IOU) providing gas service in California.[2]

The Phase 4 Scoping Memo outlined three specific action items necessary to implement SB 1440: (1) consultation with the California Air Resources Board (CARB), (2) a determination as to whether biomethane procurement targets or goals can be adopted in a cost-effective manner while complying with all

[1] Bio-SNG derives from noncombustion thermal conversion, such as pyrolysis and gasification, of exclusively organic material. The feedstocks generally consist of woody biomass, such as forest waste, agricultural waste, and urban wood waste. Bio-SNG is defined in the Senate Bill 1440 Staff Proposal as follows: "A mixture composed primarily of methane, carbon dioxide, and water produced by chemical conversion (catalytic methanation) of purified and conditioned renewable syngas. Also contains low concentrations of carbon monoxide, hydrogen, and other minor constituents."

[2] Phase 4 also includes considerations of various hydrogen-related issues, which were either addressed in Application (A.) 20-11-004 or will be addressed later in this proceeding.

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).[3] A subsequent amendment to the Phase 4 Scoping Memo issued June 5, 2020, added seven additional issues (*see* Section 2.2 below).

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) recommending establishment of a biomethane procurement program for California's four large gas IOUs, a copy of which was attached to the Biomethane Procurement Ruling. The Biomethane Procurement Ruling directed parties to address four specific questions related to the Staff Proposal, as well as any relevant issues not addressed in the Staff Proposal.

1.1. Summary of Staff Proposal

The Staff Proposal recommends approval of a mandatory biomethane procurement program for California's four large gas IOUs – Southern California Gas Company (SoCalGas), Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (SWG) (collectively, the Joint Utilities) – to assist the state in meeting the short-lived climate pollutant (SLCP) emissions reduction goals established by SB 1383 (Lara, 2016).[4] The Staff Proposal would require the Joint Utilities to procure

[3] *See Pub. Util. Code Section 651 (b)*: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=651.&lawCode=PUC.

[4] *Methane* is an SLCP.

biomethane produced from organic waste for their core customers[5] to help meet California's statutory obligation to divert 75 percent of 2014 organic waste levels away from state landfills by the end of 2025.

After the Joint Utilities have met the 2025 procurement target for biomethane sourced from organic waste diverted from landfills, the Staff Proposal would allow them to procure biomethane from any source other than dairy operations while still prioritizing procurement of biomethane from organic waste diverted from landfills. Dairy biomethane is excluded so it can be used for low-carbon fuel standard (LCFS)-related purposes in the transportation sector. By 2030, the Joint Utilities would be required to procure 72.8 billion cubic feet (Bcf) of biomethane annually,[6] which the Staff Proposal states is equivalent to approximately 12.3 percent of total annual statewide gas IOU core customer consumption in 2020.

The Staff Proposal would require all biomethane procurement to be cost-effective according to a methodology to be developed by the Joint Utilities and approved by the CPUC. All biomethane procurement contracts would be

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[5] Gas utilities provide definitions of core and noncore customers in the California Gas Report glossary.

The definitions are consistent with the definition for "core" in D.86-12-009. Core customers use less than 20,800 therms per month and are generally residential and small commercial operations. Noncore customers are commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements. *See*: https://www.socalgas.com/regulatory/cgr.

[6] This volume derives from CARB's target of an estimated four million metric ton carbon dioxide *equivalent* ($MMTCO_2e$) greenhouse gas (GHG) reduction from avoided landfill methane emissions identified in CARB's 2017 Scoping Plan by redirecting 27 million tons of organic waste from landfills, 18 of which must go to compost, anaerobic digestion, co-digestion, wood chipping, or other organic waste processing facilities.

submitted for approval by advice letter at tiers determined by the cost of each contract. Each gas IOU would also be required to submit a biomethane procurement plan for CPUC approval outlining its biomethane procurement strategy through 2030 and the anticipated bill and rate impacts associated with that procurement. To be eligible to contract with an IOU, biomethane producers would have to meet several eligibility conditions. In 2025, the CPUC would revisit the procurement targets and adjust them, as necessary, in response to market conditions.

1.2. Parties Responding to Staff Proposal

On June 30, 2021, comments were received from the following parties: Agricultural Energy Consumers Association (AECA); Anaergia Services (Anaergia); Bioenergy Association of California (BAC); California Association of Sanitation Agencies (CASA); Central California Asthma Collaborative, Food & Water Watch, Leadership Counsel for Justice and Accountability (collectively, LCJA); Clean Energy; Coalition for Renewable Natural Gas (CRNG); Dairy Cares; Electrochaea Corporation (Electrochaea); Environmental Defense Fund (EDF); Gas Technology Institute (GTI); Joint Utilities; Shell Energy North America (Shell); Sierra Club; The Utility Reform Network (TURN); and True North Renewable Energy (True North). Lawrence Livermore National Laboratory (LLNL), a non-party, also served comments on the service list.[7]

On July 16, 2021, reply comments were received from the following parties: AECA; BAC; California Bioenergy LLC (CalBio); CASA; Clean Energy; CRNG; Dairy Cares; EDF; Electrochaea; Indicated Shippers, California Manufacturers & Technology Association (collectively, Indicated Shippers); Joint

[7] Nothing in this decision relies on LLNL's comments.

Utilities; LCJA; Maas Energy Works (MEW); Shell; Sierra Club; Southern California Generation Coalition; and True North.

2. Issues Before the Commission

2.1. Issues Specified in the Original Phase 4 Scoping Memo

The original Phase 4 Scoping Memo issued November 21, 2019, directed parties to address the following seven issues:

1. What are appropriate biomethane procurement targets for each gas corporation?
2. Could the procurement targets be met by any renewable gas that complies with applicable pipeline injection standards?
3. The recommendations developed pursuant to Health and Safety Code Section 39730.8 (Pub. Util. Code Section 651(b)(1).)
4. Are the targets or goals consistent with waste disposal requirements of Health and Safety Code 39730.6 and regulations adopted pursuant to Public Resources Code 42652.5. (Pub. Util. Code Section 651(b)(2).)
5. How to determine if the biomethane procurement meets the requirements set forth in Pub. Util. Code Section 651(b)((3)(B)(i)?
6. How to demonstrate that the biomethane procurement meets at least one of the requirements of Pub. Util. Code Section 651(b)(3)(B)(ii)?
7. How will IOUs recover the costs of meeting procurement targets? What is the expected impact on rates?

2.2. Issues Specified in the Amended Phase 4 Scoping Memo

The amended Phase 4 Scoping Memo issued June 5, 2020 added the following seven additional issues:

1. Whether to base a procurement target on greenhouse gas (GHG) emission reductions achieved, rather than gas volume, or adopt other provisions to ensure that GHG reductions are maximized?
2. Which biomethane sources have the greatest short-lived climate pollutant reduction benefit? Should procurement be limited to, or prioritize, those sources?
3. How to ensure there are environmental benefits from the procurement that accrue to the utility and/or its customers, and are not used or claimed by another entity?
4. What fuel certification and verification measures are appropriate?
5. What are reasonable estimates of the supply of biomethane available to meet a procurement target as well as meet other demands, including for alternative vehicle fuels?
6. How can we ensure that the procurement will not frustrate or conflict with efforts to decarbonize buildings through electrification?
7. How can we ensure that the impact of meeting procurement targets on rates paid by consumers is reasonable?

The Staff Proposal addresses these issues under three broad headings: (1) Cost-Effectiveness, (2) Procurement Targets, and (3) Other Considerations. We consider each in turn.

3. Discussion and Analysis

3.1. Staff Proposal

3.1.1. Staff Cost-Effectiveness Proposal

The Staff Proposal recommends that the Joint Utilities develop a uniform Standard Biomethane Procurement Methodology (SBPM) for determining the cost-effectiveness of procuring biomethane and submit it for CPUC approval as a Tier 2 Advice Letter. The SBPM would serve as the cost-effectiveness test that determines whether the biomethane procured provides the most GHG reduction benefit at the least cost. It will require 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 uniform SBPM would have inputs, outputs, and transparency by using a model similar to the Oregon gas utility NW Natural's cost-effectiveness test but would need to be modified to incorporate California-specific procurement requirements, including benefits such as SLCP reduction and environmental justice.

The Staff Proposal does not propose allocation of gas IOU biomethane procurement costs among noncore customers, noting that the CPUC cannot direct procurement decisions by entities that supply gas to noncore customers. However, it adds that "[i]f there is a method within existing rules and regulations in which the gas IOUs can attribute a portion of their biomethane procurement costs to noncore customers, the burden is on the gas IOUs to provide proof and rationale for charging those noncore customers a higher rate."[8]

[8] SB 1440 Staff Proposal at 51.

Regarding the contract approval process, the Staff Proposal recommends that individual biomethane procurement contracts should be submitted for CPUC approval using a three-tier advice letter process:

A Tier 1 Advice Letter for prices below $17.70/MMBtu, based on market estimate of average cost of biomethane.

A Tier 2 Advice Letter for prices between $17.70 and $26/MMBtu, the latter reflecting the social cost of methane.[9]

A Tier 3 Advice Letter for prices $26/MMBtu and above.

3.1.2. Staff Procurement Proposal

3.1.2.1. Short-Term Procurement

The Staff Proposal recommends a short-term target of procuring sufficient biomethane to divert eight million tons of organic waste from landfills in order to support the 2025 California Department of Resources Recycling and Recovery (CalRecycle) organic waste diversion goal established by SB 1383 (Lara, 2016). CalRecycle estimates that the state's infrastructure will be able to process 10 million tons of organic diverted waste in 2025, well short of its goal of

[9] The $26/MMBtu value is based on the most recent 2021 federal Interagency Working Group (IWG) estimate of the social cost of methane and will be adjusted based on subsequent federal updates thereto. "Social cost of methane" as used herein means the monetary value of the net harm to society associated with adding a small amount of methane to the atmosphere in a year. In principle, it includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. *See* February 2021 report of the federal Interagency Working Group on Climate Change available here: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

18 million tons diverted. Thus, achieving this short-term target will make up for the projected shortfall in organic waste diversion.[10]

3.1.2.2. Medium-Term Procurement

The Staff Proposal recommends a procurement target of 75.5 million MMBtu (72.8 Bcf) of biomethane annually by 2030 to correspond with CARB's 2030 landfill methane reduction goals from the 2017 Scoping Plan.[11] The gas IOUs would be required to continue prioritizing the procurement of biomethane sourced from organic waste diverted from landfills to meet the medium-term target but would be allowed to procure from most other sources, as well. Dairy biomethane would not be eligible for meeting the medium-term procurement targets. Dairy biomethane is in high demand and commands high prices in the LCFS program. Should landfill gas be procured after 2025, the Staff Proposal recommends that landfill operators be required to use technologies to better capture methane emissions and better optimize operations.

3.1.2.3. Procurement Guidelines

The Staff Proposal recommends that a biomethane procurement program should maximize benefits for the communities in which biomethane is produced. Not all biomethane production facilities are necessarily equal in terms of their local impacts. The Staff Proposal asserts that procurement decisions should use a holistic approach by taking into consideration the ways in which life cycle

[10] "CalRecycle estimates …approximately 18 million tons of organic waste that will need to be processed at compost, [anaerobic digesters] AD, or chip-and-grind facilities. However, based on current capacity projections, the state will only be able to process about 10 million tons of this material." Thus, based on a projected 2025 shortfall in infrastructure capacity at compost, AD, or chip-and grind facilities, there is a need for additional capacity for eight million tons of organic waste diverted from landfills. *See* CalRecycle "Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals" (2020) https://www2.calrecycle.ca.gov/Publications/Download/1589.

[11] SB 1383 requires CalRecycle to divert 75% of 2014 levels of organic waste.

biomethane production would contribute to or detract from economic, health, and non-energy benefits for local communities.

3.1.3. Other Staff Recommendations

3.1.3.1. Carbon Monoxide Limit

The Staff Proposal recommends adopting an interim permissible amount of carbon monoxide (CO) in biomethane of 0.03 mole percent, in accordance with Battelle Columbus Laboratories research. This CO standard should remain in place until the Office of Environmental Health Hazard Assessment (OEHHA) and CARB are authorized and able to assess the potential dangers of CO and other chemicals associated with bio-synthetic natural gas (bio-SNG) production. The Staff Proposal further recommends authorizing an appropriate IOU to contract for a study of constituents found in various sources of bio-SNG outside of California so that OEHHA and CARB have a robust data set from which to analyze and make recommendations.

3.1.3.2. Hydrogen Sulfide Limit

The Staff Proposal recommends requiring that the Joint Utilities only procure biomethane from producers who contractually limit hydrogen sulfide (H_2S) concentrations in biogas entering their gathering lines[12] to 10 parts per million (ppm), the Occupational Safety and Health Administration (OSHA) allowable work limits over an eight-hour period and industry standards. The Staff Proposal asserts that H_2S is a toxic chemical that is dangerous to human health and safety, thus CPUC should require the Joint Utilities procure from sellers that agree to limit H_2S to 10 ppm in the gathering

[12] Gathering lines are lines used to transport biomethane from its source to the gas utility where it can be combined with methane from other sources for delivery to customers. Pub. Util. Code Section 950(a)(3) defines a "gathering line" as "a pipeline that transports gas from a current production facility to a transmission line or main."

lines, as the California Department of Food and Agriculture currently requires of participating facilities in the Dairy Digester Research and Development Program (DDRDP).

3.1.3.3. Biomethane Procurement Plan

The Staff Proposal recommends requiring that each gas IOU submit a Biomethane Procurement Plan (BPP) that contains estimated annual biomethane procurement levels, ratepayer bill impacts, and any incremental capital infrastructure and/or operations and maintenance costs associated with those procurement levels through the end of 2030. According to the Staff Proposal, these BPPs should be submitted as Tier 3 advice letters.

3.1.3.4. Tipping Fees

The Staff Proposal recommends requiring contingencies in biomethane procurement contracts to account for increases in tipping fees[13] such that the procurement price lowers if tipping fees are raised. Both tipping fees and biomethane sales generate revenue for a biomethane production facility. Thus, the Staff Proposal asserts that a contingency to renegotiate contracts when tipping fees change can help offset revenue increases or decreases to support biomethane producers while also protecting consumers.

3.1.3.5. Prohibition of Diesel Vehicles

The Staff Proposal recommends prohibiting the Joint Utilities from procuring biomethane from any production facility that does not commit to the prospective exclusive use of low carbon fuel or zero emission vehicles as part of any expanded operations.

[13] Tipping fees are the fees charged by a landfill to accept waste. Per the Staff Proposal, a "tipping fee" is a fee paid by anyone who disposes of materials at a waste processing facility.

3.1.3.6. On-Site Generator Restrictions

The Staff Proposal recommends that the Joint Utilities prioritize procurement of biomethane from facilities that agree to not increase on-site electric generation produced by gaseous combustion so as to avoid air quality impacts to local communities.[14] A facility would be allowed to increase on-site electric generation using biomethane—not raw biogas—in a fuel cell that does not combust the gas.

3.1.3.7. Carbon Capture and Storage Requirements

The Staff Proposal recommends that the Joint Utilities prioritize procuring biomethane from producers that use carbon capture and storage (CCS) because California's geography in many areas is well-suited for CO_2 storage.

3.1.3.8. Core Transport Agent Requirements

The Staff Proposal recommends requiring Core Transport Agents (CTAs) to meet or exceed the level of biomethane procured by the gas IOU that they are competing with in their customer offerings. The Staff Proposal notes that the CPUC does not have express statutory authority over CTA procurement and accordingly recommends the adoption of legislation to provide it this authority.

3.1.3.9. Soil Amendment Requirements

The Staff Proposal recommends that the Joint Utilities prioritize procurement of biomethane from production facilities that agree to convert their waste byproduct into soil amendment such as biochar.

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[14] A CEC study found that "biogas and biomethane combustion exhaust is similar to natural gas combustion exhaust." Kleeman, Michael J., Thomas M. Young, Peter G. Green, Stefan Wuertz, Ruihong Zhang, Bryan Jenkins, Norman Y. Kado, and Christopher F.A. Vogel. 2020. Air Quality Implications of Using Biogas to Replace Natural Gas in California. California Energy Commission. Publication Number: CEC-500-2020-034 at 128. *See*: https://ww2.energy.ca.gov/2020publications/CEC-500-2020-034/CEC-500-2020-034.pdf.

3.1.3.10. Pilot Projects for Converting Biomass to Biomethane

The Staff Proposal recommends that California's two largest gas IOUs—PG&E and SoCalGas—each submit an application to the CPUC by no later than the end of 2022 for one pilot project that can convert forest waste and any available agricultural waste into biomethane. The pilot projects would be required to be strategically located to process maximal waste amounts, and SoCalGas and PG&E would be required to consult with state and local authorities on project locations. The Staff Proposal further recommends that SoCalGas and PG&E propose ways in which any hydrogen or CO_2 produced by the facility would be utilized instead of vented into the atmosphere.

3.2. Responses to Staff Proposal

3.2.1. Party Responses to Staff Cost-Effectiveness Proposal

Multiple parties including EDF, CRNG, AECA, LCJA, Sierra Club, Dairy Cares and Clean Energy state there should be a workshop for public testimony, record development, and public review of a cost-effectiveness test. Additionally, EDF and the Joint Utilities assert that a Procurement Advisory Group should be required, as established in Decision (D.) 20-12-022 implementing the Voluntary Renewable Natural Gas Tariff (VRNGT). EDF and the Joint Utilities also assert that, similar to renewable electricity procurement, intervenor compensation should be available for participating parties. Collectively, parties assert that cost-effectiveness should not be the only metric used for biomethane procurement, so the cost-effectiveness test should incorporate SLCP reductions, carbon intensity, additionality, verifiability, and certification.

3.2.2. Party Responses to Staff Procurement Proposal

3.2.2.1. Party Responses to Staff Short-Term Target Proposal

BAC states that the Staff Proposal's short-term target should be resource neutral because limiting the source to wastewater treatment plants and standalone anaerobic digesters processing organic waste diverted from landfills would make the program overly restrictive. To ensure source diversity, BAC urges the Commission to put a cap on landfill gas procurement. Additionally, BAC notes that Assembly Bill (AB) 1900 states CPUC "policies and programs shall facilitate the development of a variety of sources of in-state biomethane" (emphasis added).

CRNG supports the proposed short-term target and finds the Staff Proposal recommendation to be reasonable.

Electrochaea calculates that eight million tons of organic waste processed in anaerobic digesters could produce 100 Bcf, which is approximately five percent of California gas demand in 2019. They assert that the Staff Proposal's short-term target is unclear because it is not a specific volume and exceeds the medium-term target.

The Joint Utilities are concerned that the short-term target will be difficult to achieve by 2025 and request that the CPUC adopt a flexible compliance approach for meeting their procurement obligations.[15]

[15] "In order for the program to be immediately successful, the Joint Utilities request that the CPUC adopt a flexible compliance approach for the 2025 short-term target. There is much to do between now and 2025. Specifically, the Joint Utilities need to obtain Commission approval of a procurement program via a Proposed Decision and submit the various AL requirements recommended in the Proposal (*e.g.*, development of a Biomethane Procurement Plan (BPP) and SBPM, develop and hold competitive solicitations, negotiate contracts, and seek approvals of

3.2.2.2. Party Responses to Staff Medium-Term Target Proposal

Party	Response
BAC & GTI	Increase annual target to 150 Bcf by 2030
Anaergia	Increase annual target to 180 MMBtu by 2030
CRNG & CASA	Support annual target at 72.8 Bcf
EDF	Establish after public review
LCJA & Sierra Club	Reject 2030 target and Staff Proposal methodology

LCJA, EDF, and Sierra Club support the short-term organic waste diversion target but argue that setting medium-term targets is premature and needs to be preceded by alternative analyses of issues such as the appropriate feedstocks, the social cost of methane, and environmental justice.

CalBio, MEW, Dairy Cares, CRNG, and AECA object to excluding dairy biomethane from medium-term targets. BAC and Shell request resource neutral procurement. Clean Energy's reply comments recommend procuring dairy biomethane to help mitigate the poor air quality in communities surrounding dairies, an issue that LCJA and Sierra Club raise also in their opening comments.

Biomethane Contracts). Without flexibility, short-term requirements may lead to higher biomethane prices…. Accordingly, the Joint Utilities request that the CPUC adopt a flexible compliance approach for the 2025 short-term target and 2030 medium-term targets, including the adoption of compliance methods such as banking and borrowing, possible trading excess supplies between the Joint Utilities, and other tools available to manage supply. The Joint Utilities recommend that the Commission direct the Joint Utilities, via the upcoming Decision in this proceeding, to coordinate on a proposed set of these flexible compliance mechanisms to be filed in their BPPs. The Commission would then authorize these mechanisms as part of the BPP approval." *Joint Utilities Opening Comments at 4-5.*

3.2.2.3. Party Responses to Procurement Guidance

TURN, Shell, CRNG, AECA, Dairy Cares, Clean Energy, LCJA, Sierra Club, True North, Electrochaea, and the Joint Utilities all support biomethane procurement policies that maximize benefits for communities in which biomethane is produced.

LCJA and EDF request a workshop on environmental justice, including impacts of the proposed procurement on disadvantaged communities from the proposed procurement.

CRNG raises a concern that including CI scores in a cost-effectiveness test may unduly delay procurement. They assert that CI scores are complex and require thorough analysis of life cycle GHG emissions before CI scores can be established in a California-specific Greenhouse Gases, Regulated Emissions and Energy Use in Transportation Model (GREET) pathway.[16] As such, an interim method may be necessary in order to encourage accelerated biomethane procurement.

3.2.3. Party Responses to Other Staff Recommendations

3.2.3.1. Carbon Monoxide Limit

Joint Utilities support an interim CO limit in the gas quality standard while OEHHA and CARB assess CO and other potential constituents of concern in bio-SNG.

[16] The CA-GREET model is a California-specific version of Argonne National Laboratory's GREET life cycle model which is used to calculate GHG emissions under the LCFS. *See*: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.

EDF opposes an interim permissible amount "until it is certified" and proposes a "Green-E standard… to consider how bio-SNG comports with that standard as well."[17]

CRNG recommends that CO should be studied in forest pyrolysis pilot projects.

3.2.3.2. Hydrogen Sulfide Limit

Parties that agree with the proposed requirement include BAC, EDF, AECA, LCJA, and Dairy Cares.

EDF agrees with the Staff Proposal that Joint Utilities procurement can require the H_2S limit in gathering lines through an agreement between the utility and seller.

The Joint Utilities point out that in D.17-12-007 the CPUC decided to allow dairy biomethane pilots to include treatment of H_2S in the biogas collection line costs but did not mandate this treatment until such time as the gas enters the utility pipeline system.

3.2.3.3. Biomethane Procurement Plan

The recommendation for a BPP requirement is supported in varying degrees by BAC, CRNG, EDF, TURN, AECA, and True North. EDF proposes renaming the proposed BPP as the "Gas Procurement Plan" to avoid confusion with "bundled procurement plan," which is commonly referred to as "BPP" in regulatory parlance. TURN and AECA stress the need for the plan to include forecasts of ratepayer impacts. True North urges the Commission to include consumer education focused on diverting food waste from landfills as part of any plan.

[17] EDF Opening Comments at 6.

LCJA and Sierra Club oppose approving a procurement plan via the use of advice letters and, like Dairy Cares, insist on a public proceeding such as a formal application to establish an evidentiary record for public analysis.

CRNG supports the Staff Proposal's recommendation that the Joint Utilities publicly file annual progress reports of actual biomethane procurement levels, ratepayer bill impacts, and incremental capital infrastructure and/or operations and maintenance costs for the prior year compared to the estimated costs in the BPP.

3.2.3.4. Tipping Fees

AECA, LCJA, and Dairy Cares support renegotiating contract prices if landfill tipping fees are increased.

Anaergia, BAC, and CRNG oppose this recommendation, stating that renegotiating contracts adds uncertainty, risk, and volatility to the contracts. They assert that certainty in long-term contracts should be prioritized.

3.2.3.5. Prohibition of Diesel Vehicles

BAC, CRNG, and LCJA support the prohibition on diesel vehicles for any newly purchased or leased vehicles associated with biomethane production facilities. While EDF opposes this prohibition within the scope of this proceeding, they propose—alongside Sierra Club and LCJA—the additional requirement the use of zero-emission vehicles.

3.2.3.6. On-Site Generator Restrictions

CRNG and LCJA support the limit on increased combustion electricity generation. LCJA recommends this especially for facilities located in non-attainment areas under the Clean Air Act.

BAC supports the limit on combustion electricity generation yet finds that it may be too restrictive, especially for wastewater treatment facilities that may

need to prioritize onsite electricity generation needed to maintain essential services over other biomethane end-uses of the feedstock. BAC recommends other non-combustion technologies such as linear generators and proposes expanding non-combustion generation beyond one specific type of technology.

CASA raises an additional issue. It asserts that the regulations of the California Division of Occupational Safety and Health (CalOSHA) are burdensome for facilities that inject more than 10,000 pounds of methane into gas IOU pipelines. An exception to the CalOSHA regulations allows facilities to subtract methane used for onsite electricity production; therefore, this may be the best option at some facilities.[18]

EDF, AECA, and Dairy Cares join CASA in expressing concern that limiting combustion electric generation may be overly restrictive and difficult to monitor and enforce.

3.2.3.7. Carbon Capture and Storage Requirements

BAC and CRNG support the CCS requirements but believe they should be modified to include carbon use (carbon capture, and storage or use ("CCS/U")) and this modification should be included in CI scoring. LCJA and EDF oppose CCS-related procurement prioritization because it is not yet a fully operational solution in California.

3.2.3.8. Core Transport Agent Requirements

CRNG, Shell, Joint Utilities, and BAC support requiring biomethane delivered by CTAs to meet or exceed the quantity of biomethane procured by the

[18] Presumably, if the amount of biomethane a facility injects into IOU pipelines is limited, there could be an increase in onsite electricity production when the facility begins processing larger volumes of organic waste diverted from landfills.

Joint Utilities and would support new legislation to that end. EDF agrees with this requirement yet believes that legislation is required to enact this proposal.

The Joint Utilities and BAC recommend the Commission adopt a nonbypassable charge that would allocate some of the gas IOUs' biomethane procurement costs to CTA and noncore customers until legislation is adopted requiring CTAs procure the same amount of biomethane as the gas IOUs. BAC recommends a similar nonbypassable charge imposed in the BioMAT program.

3.2.3.9. Soil Amendment Requirements

CRNG, AECA, and Dairy Cares support using biosolids produced from the feedstocks as a soil amendment.

CASA supports use of digestate, which they assume includes biosolids, as a soil amendment.

BAC proposes a modification for byproduct reuse to include end uses such as water purification, cement, or other industrial purposes. The byproduct end-use should be decided on a project-by-project basis.

LCJA disagrees with the soil amendment requirement because farm-derived waste byproduct is already used as a soil amendment. They further assert that nutrients and other compounds in digestate have a higher chance of leaching or running into ground or surface waters compared to undigested manure.

3.2.3.10. Pilot Projects for Converting Biomass to Biomethane

EDF, GTI, AECA, BAC, and the Joint Utilities support the Staff Proposal's two recommended pilot projects for woody biomass pyrolysis or gasification.

AECA, CRNG, Shell, and Dairy Cares remain neutral on the issue.

BAC recommends expanding the pilot program by including other sources of wood waste such as forest, agricultural, and urban wood waste in six pilot

projects, similar to the dairy biomethane pilot projects approved by the CPUC in response to SB 1383.

Sierra Club opposes the Staff Proposal's two recommended pilot projects and asserts that forest thinning for fuels reduction is a net carbon emission from the forest. In lieu of producing methane from woody biomass, Sierra Club recommends other solutions for wood waste such as soil amendments and compost.

3.2.4. Issues Not Addressed by the Staff Proposal

Parties raised six additional matters not addressed in the Staff Proposal:

3.2.4.1. Methane Leaks

CRNG, EDF, Sierra Club, LCJA, and True North raise concerns that methane leaks from biomethane facilities or pipelines will exacerbate climate-related efforts. EDF proposes a leak rate limit and a requirement that the seller demonstrate sufficient air quality permits to enable operations, particularly at the point of injection. CRNG proposes factoring methane leaks into a CI score to incorporate facility leakage monitoring into the life cycle analysis, thereby providing an incentive to minimize leaks associated with biomethane production and pipeline injection. EDF proposes periodic inspection against leakage at points of interconnection and monitoring to ensure environmental integrity through the life of the contract.

3.2.4.2. Integration With the Voluntary Renewable Natural Gas Tariff

CRNG, EDF, and the Joint Utilities each filed comments requesting that biomethane procured for SB 1440 be allowed to layer with procurement for the VRNGT.

3.2.4.3. Compressed Natural Gas Fueling Stations

In the Joint Utilities' opening comments, SoCalGas and SDG&E request that the CPUC make the compressed natural gas (CNG) fueling station pilot program approved in AL 5295-G permanent in this decision.[19]

3.2.4.4. Renewable Thermal Certificate Tracking

The Midwest Renewable Energy Tracking System (M-RETS), a proprietary web-based platform that tracks Renewable Energy Certificates (RECs) and Renewable Thermal Certificates (RTCs), filed comments on January 10, 2020, in response to a December 17, 2019 ALJ ruling permitting additional comments on SB 1440 implementation. M-RETS recommends that California use their transparent system that issues unique traceable digital certificates to verify carbon intensity pathways such as GREET and compliance in SB 1440.

3.2.4.5. Contract Duration

Party	Response
Anaergia	20 years
GTI	Up to 20 years
BAC	10, 15, or 20 years
EDF & CRNG	10 years

BAC states, "[b]iomethane producers should be able to choose between 10, 15, and 20-year contracts similar to the BioMAT and ReMAT programs. Offering only 10-year contracts is unlikely to attract many biomethane producers, especially in the highest value and more expensive feedstock categories." BAC further asserts that contracts should also include an inflation adjustment adder.

[19] While the Joint Utilities only mention AL 5295-G, the Staff Proposal points out that a similar request was granted for PG&E in response to AL 3961-G.

3.3. Adopted Courses of Action

3.3.1. Adopted Actions on Cost-Effectiveness

We agree with party comments that various complex issues such as cost-effectiveness, environmental justice, additionality, and verifiability must be addressed in a public forum with an opportunity for parties to submit comments before finalizing program requirements. Accordingly, we require Energy Division to host a workshop on cost-effectiveness within one month of the effective date of this decision. The workshop shall also address biomethane procurement planning (*see* Section 3.3.3.3 for further discussion).

The workshop shall include panelists from each of the following types of groups: gas IOUs, environmental advocates, environmental justice advocates, biomethane producers and consumer advocates. In addition, the public shall be invited to participate in question-and-answer sessions. Topics to discuss at the workshop shall include, but not be limited to, the following:

1. What specific items should be required in a joint advice letter regarding the SBPM cost-effectiveness test?
2. What specific items should be required in an advice letter regarding the cost elements of a biomethane procurement plan?
3. How should CI be measured in the SBPM cost-effectiveness test?
4. What criteria shall be used in a preliminary cost-effectiveness test while a modified GREET model is being developed?

At the workshop, Energy Division may distribute specific proposals addressing questions one through four and other related matters as part of a workshop agenda. The workshop agenda shall also include discussion of environmental justice and community benefits related to biomethane procurement. Within three months of the workshop, the Joint Utilities shall

include results of the workshop and address feedback received at the workshop in advice letters establishing the SBPM and their respective procurement plans. The CPUC shall evaluate the SBPM according to the criteria identified in the workshop. The advice letters will remain eligible for protest and public comment in accordance with General Order 96.

We agree with TURN, Indicated Shippers, and the Joint Utilities that the CPUC should consider distributing above-market biomethane procurement costs to noncore customers "by either including the costs in the gas public purpose program or in a new nonbypassable charge that all noncore and CTA customers must pay"[20] or by some other means. We find that it is appropriate to address this issue in a separate ratesetting proceeding because this is a quasi-legislative proceeding. A proceeding shall be opened no later than January 1, 2023, to address the topic of noncore cost sharing of biomethane procurement costs.

We agree with the Staff Proposal and True North that biomethane procurement contracts should be submitted according to the proposed three-tier advice letter process and clarify that the tiers are neither a cost-effectiveness test nor a method for prioritizing projects. Rather, the tiers are merely a procedural mechanism for the CPUC to review contract submissions. We also agree with EDF and the Joint Utilities that a Procurement Advisory Group, as established in the VRNGT decision (D.20-12-022), should be required for SB 1440 procurement. As with the Procurement Advisory Group established in D.20-12-022, participants in the Procurement Advisory Group will not be allowed to claim intervenor compensation.

[20] TURN opening comments at 11.

3.3.2. Adopted Actions on Procurement

3.3.2.1. Adopted Actions on Short-Term Procurement

We adopt the Staff Proposal's recommended short-term target of procuring biomethane that achieves eight million tons of organic waste diverted annually from landfills. Each of the Joint Utilities shall be responsible for diverting a percentage of the eight million tons of organic waste according to each of their respective Cap-and-Trade allowance shares: SoCalGas 49.26 percent, PG&E 42.34 percent, SDG&E 6.77 percent, and SWG 1.63 percent.

We acknowledge that it may be difficult to achieve the eight million-ton target by 2025, as addressed in the Joint Utilities' opening comments, but recommend that the gas IOUs' respective procurement plans should evaluate feasibility and provide guidance on compliance mechanisms necessary to meet the 2025 target. Additionally, we acknowledge that strict adherence to the target may adversely affect biomethane prices if the Joint Utilities are captured customers (*i.e.*, required to purchase limited biomethane supply and accordingly forced to pay above market rates to adhere to a strict or inflexible target). Thus, the Joint Utilities may adopt flexible compliance methods similar to the methods introduced pursuant to SB 1078 (Sher, 2002) for the initial implementation of the Renewables Portfolio Standard (RPS) program (*see* D.03-06-071, Ordering Paragraphs 20-22): utilities are allowed unlimited forward banking of excess procurement; procurement in any year shall be applied first to that year's annual procurement target, with any excess procurement then being used to make up a prior year's deficit, or banked for future use; utilities are allowed to carry over an annual deficit of 25% to the next three years without explanation; utilities are allowed to trade excess supplies among themselves and to procure on behalf of each other. If the 2025 diverted

organic waste target is met or can foreseeably be met ahead of schedule, then the option of additional procurement from other biomethane feedstocks is permitted during the short-term target timeframe.

3.3.2.2. Adopted Actions on Medium-Term Procurement

Party comments cite sources of additional feedstock that were not reflected in the Staff Proposal, such as 15 million tons of woody biomass waste that will be available annually as a result of forest management, agricultural waste, and urban wood waste. Some parties recommend more aggressive procurement targets to help prevent wildfire emissions that can exacerbate climate change with black carbon, another highly potent SLCP. Thus, we conclude that a small increase in the Staff Proposal target from 12.3 percent to 15 percent core customer demand rate at 2020 levels is reasonable. We adopt a medium-term target for the Joint Utilities to each individually procure 15 percent of their 2020 annual core customer natural gas demand by 2030 and beyond, which is approximately 88 Bcf of biomethane, as forecasted in the 2020 California Gas Report for an average temperature year.[21] This 15 percent core customer procurement target may be referred to as a "Renewable Gas Standard." This target is inclusive of the biomethane procured to meet the short-term target, as well as all bio-SNG procurement, but excludes biomethane procured for transportation customers as part of the LCFS program, whether by a gas IOU or anyone else. We will re-evaluate this target in 2025 after taking into consideration progress made toward achieving the short-term target. Over time, as the total volume of gas

[21] California Gas Report models two scenarios for forecasting purposes: (1) average temperature year and (2) cold dry year. *See*: 2020 California Gas Report at 21 https://www.socalgas.com/sites/default/files/2020-10/2020_California_Gas_Report_Joint_Utility_Biennial_Comprehensive_Filing.pdf.

usage is expected to decrease due to building electrification and other factors (*e.g.*, increased RPS procurement, improved energy efficiency, etc.), maintaining 88 Bcf of biomethane per year will result in annual percentages of biomethane that are higher than 15 percent. The flexible compliance mechanisms we establish for the short-term 2025 target will apply to the medium-term 2030 target, as well. However, the Joint Utilities shall use their best efforts to achieve the 88 Bcf medium-term target in 2030, or as soon as possible after this date.

We adopt the Staff Proposal's recommended dairy biomethane exclusion. Furthermore, in response to comments from LCJA, we clarify that the IOUs may not procure any livestock biomethane for this program. Livestock biomethane is currently in high demand for decarbonizing transportation fuel through the LCFS program and is not authorized for this program unless the LCFS program rules are modified to exclude it. In that event, we grant the Joint Utilities the option to procure livestock biomethane for meeting medium-term targets and beyond. This livestock biomethane procurement exclusion will help provide procurement opportunities for other biomethane sources that may not currently participate in the LCFS program in great numbers. We may re-evaluate the livestock biomethane procurement exclusion in 2025 when targets are re-evaluated. This decision does not modify any other decisions or agency actions regarding livestock biomethane.

3.3.2.3. Adopted Actions on Procurement Guidelines

We direct the Joint Utilities to include environmental assessments and social justice impacts as part of their biomethane procurement practices in their respective procurement plans. We adopt the Staff Proposal's recommendation

that procurement decisions should take into consideration the ways in which modifications and/or expanded operations at a wastewater treatment plant, landfill, or other facility to increase biomethane production would contribute to or detract from economic, health, and non-energy benefits for local communities. These non-GHG community impacts are important to balance cost-effectiveness metrics. Non-GHG impacts may justify a decision to either not procure or reduce procurement from certain facilities even if they offer a lower cost and/or impose contractual requirements to reduce or avoid adverse community impacts.

We adopt the modified GREET model from the VRNGT program in Ordering Paragraph 1.b.i of D.20-12-022. This model will be used to determine CI scores. The Joint Utilities are directed to report CI scores in their Advice Letters seeking approval of a procurement contract. The CI score for purposes of SB 1440 procurement will be used for contract review and procurement decisions. However, the CI score can change as production facilities change; thus, ongoing CI score management shall be subject to review as part of the new proceeding that will review biomethane targets in 2025. To encourage accelerated procurement while a production facility processes CI calculations under the modified GREET model, and while the modified GREET model is being developed, we direct the Joint Utilities to start procurement as soon as possible, using a preliminary cost-effectiveness test that estimates the SLCP reduction and life cycle carbon emissions until a CI score is established.

3.3.3. Adopted Actions on Other Staff Recommendations

3.3.3.1. Carbon Monoxide Limit

We agree with the Staff Proposal and the Joint Utilities' opening comments that it is appropriate to adopt an interim permissible amount of CO in biomethane of 0.03 mole percent to account for bio-SNG gas quality. To

implement this new requirement, we direct the Joint Utilities to update the SRGIT to add "Carbon Monoxide" to the list of Integrity Protective Constituents in Table 1 ("Maximum Constituent Concentrations") with a Trigger Level of 0.03 mole percent and both Lower Action Level and Upper Action Level denoted as "TBD" pending further review. Because the SRGIT did not envision biomethane produced from anything other than anaerobic digestion, we instruct the Joint IOUs to further revise footnote four of Table 1 after ("Publicly Owned Treatment Works" or "POTW")" to add "and the noncombustion thermal conversion of organic waste." The "Other" column where "Testing for Gas Source" is specified in Table 1 should be checkmarked for CO testing. These changes to the SRGIT should be implemented via a Tier 2 Advice Letter to be submitted by the Joint Utilities within 30 days of the effective date of this decision or within 30 days of the date of approval of the advice letter filing specifying upper and lower action levels for ammonia, mercury, and siloxanes pursuant to Ordering Paragraph 11 of D.20-12-031, whichever comes later. This requirement may be revised in the future following new research findings by OEHHA and CARB.

We further agree with the Staff Proposal that additional study of potential constituents of concern in bio-SNG is merited. However, we disagree with the Staff Proposal that one of the Joint Utilities should contract for such a study. We instead authorize the CPUC, in collaboration with OEHHA, to contract with a research institution and/or private company with expertise in bio-SNG research to conduct further study of constituents found in various sources of bio-SNG and/or conduct any necessary laboratory analysis. The contract shall not exceed $1 million. Following formal execution of the contract, the Joint Utilities shall reimburse CPUC for total contract costs. Contract cost responsibility shall

be borne from each respective IOU's public purpose program funds and shall be apportioned at the percentages defined by D.20-12-031 for Cap-and-Trade allowance share: SoCalGas 49.26 percent, PG&E 42.34 percent, SDG&E 6.77 percent, and SWG 1.63 percent.

3.3.3.2. Hydrogen Sulfide Limit

We agree with the Staff Proposal, BAC, EDF, AECA, LCJA, and Dairy Cares that high levels of H_2S in gathering lines poses a potential safety hazard and should be mitigated to reduce risks to both workers and members of the general public in the vicinity of a gathering line. In the interest of public safety, the CPUC requires the Joint Utilities modify the Standard Renewable Gas Interconnection Agreement (SRGIA) to explicitly require a biomethane supplier to demonstrate and agree on an ongoing basis that the biogas it produces has its H_2S levels reduced to 10 ppm or less prior to entering a gathering line so as to match industry standards and allowable eight-hour work limits established by OSHA. To formalize this requirement, the Joint Utilities are directed to file Tier 2 Advice Letters within 30 days of the effective date of this decision updating the Standard Renewable Gas Interconnection Agreement to reflect the new H_2S restrictions. This decision updates the requirements for the biomethane incentive reservation system requirements established in D.19-12-009 for future applications. The Joint Utilities are further directed to file Tier 2 Advice Letters within 30 days of the effective date of this decision updating the Incentive Reservation Form to ensure that biomethane producers seeking a monetary incentive acknowledge this new requirement. A biomethane producer who is already on the waitlist to receive a monetary incentive shall be required to acknowledge and comply with this new requirement.

3.3.3.3. Biomethane Procurement Plans

We agree with the Staff Proposal and comments from CRNG, AECA, Dairy Cares, EDF, and the Joint Utilities that procurement plans are necessary for research and analysis regarding economic, GHG, and other related costs and benefits. We disagree with Sierra Club and do not believe a workshop is necessary to help determine whether a Tier 3 Advice Letter is a sufficient procedure. We find that a workshop to establish a cost-effectiveness test, a Procurement Advisory Group and a Tier 3 advice letter process requiring a resolution, public comment and Commission vote are sufficient for public participation and procedure.

We hereby rename BPP to "Renewable Gas Procurement Plan" (RGPP) to avoid confusion with the "bundled procurement plan" acronym and order a workshop on RGPP as discussed in Section 3.3.1, above.

The RGPPs will be public filings submitted as Tier 3 Advice Letters to the CPUC. Annual reporting currently required in this proceeding shall be updated to include accounting for biomethane procured pursuant to this decision detailing actual biomethane procurement levels, ratepayer bill impacts, and incremental capital infrastructure and/or operations and maintenance costs for the prior year compared to the estimated levels that were approved in their respective RGPPs.

3.3.3.4. Tipping Fees

We disagree with the Staff Proposal that biomethane contracts should be renegotiated if a producer increases its tipping fees. We agree with Anaergia, BAC, and CRNG that such a requirement would add uncertainty and risk to long-term contract pricing and therefore decline to require any contract modification due to tipping fee changes. However, we agree with the Staff

Proposal, AECA, LCJA, and Dairy Cares that tipping fees have a direct impact on contract pricing that should not go unaddressed. As such, we require that any biomethane procurement contract between a project developer and an IOU specify how tipping fees may modify contract terms, if at all, and direct staff to scrutinize contracts submitted for formal approval to ensure that each contract meets this requirement.

3.3.3.5. Prohibition of Diesel Vehicles

We agree with the Staff Proposal, BAC, CRNG and LCJA that the Joint Utilities should be prohibited from procuring biomethane from facilities that do not commit to exclusively purchase and/or lease either near-zero emissions (NZE) or zero-emissions (ZE) vehicles prospectively. This requirement is specific to the facility and/or facilities that the biomethane is to be procured from and does not necessarily commit the producer to exclusively purchase NZE or ZE vehicles used in other facilities or for other aspects of its operations. Any gas-powered vehicle shall exclusively use bio-CNG rather than fossil gas. The biomethane production facility that the Joint Utilities contract with shall be required to agree to such terms, declare all existing vehicles currently used in their operations, and inform the IOU it contracts with whenever a new vehicle is purchased or leased for use at the facility from which the biomethane is being procured. We direct Energy Division Staff to ensure that contracts that are approved include said provisions.

The GHG and environmental benefit of NZE and ZE vehicles shall be added to the CI score, as CRNG recommended, to estimate production facility emissions and create additional incentives for converting previously purchased or leased vehicles to NZE or ZE.

3.3.3.6. On-Site Generator Restrictions

We agree with the Staff Proposal, as well as BAC, CRNG, and LCJA, that the Joint Utilities should prioritize procurement from facilities that agree to prospectively cap on-site electrical generation from combustion of biogas or biomethane. We agree with LCJA that such a cap is especially important for facilities located in non-attainment areas under the Clean Air Act. As such, we make this cap a procurement requirement, rather than a priority, to ensure that this program does not exacerbate exceedances of air quality standards for facilities located in a county listed as a severe or extreme federal nonattainment area for particulate matter (PM-10 or PM-2.5) or eight-hour ozone (O_3) in the U.S. Environmental Protection Agency Green Book in any of the three years prior to the date of this decision.[22] We model this requirement on Pub. Util. Code Section 8388 regarding bioenergy facilities generating electricity in the Bioenergy Renewable Auction Mechanism program, which states: "[t]his section shall not apply to facilities located in federal severe or extreme nonattainment areas for particulate matter or ozone" and D.21-06-005, Ordering Paragraph 1.e, in the Self-Generation Incentive Program (R.20-05-012).

We further agree with BAC that non-combustion technology should not be limited solely to fuel cells and instead allow this contractual term to be met using a technology-neutral approach. The Joint Utilities shall ensure that contracting facilities must disclose current annual on-site electricity generation from the combustion of biogas and/or biomethane and commit contractually to not exceed those levels prospectively. The Joint Utilities are required to address how priority would be given to complying facilities in their SBPM, as well as any

[22] *See*: U.S. Environmental Protection Agency Greenbook list of nonattainment counties by year, available here: https://www3.epa.gov/airquality/greenbook/anayo_ca.html.

facility that further commits to capturing, storing, or utilizing CO_2 that would otherwise be vented into the atmosphere.

3.3.3.7. Carbon Capture and Storage

We agree with the Staff Proposal, as well as BAC and CRNG, that the Joint Utilities should be required to prioritize procurement from facilities that can prevent CO_2 from venting into the atmosphere. We agree with BAC and CRNG that a more expansive requirement should be adopted that includes "use" in addition to capture and storage, and we thus recast this requirement as "CCS/U" instead of merely "CCS." Permissible uses of CO_2 that effectively prevent it from entering the atmosphere include but are not limited to carbon mineralization, geologic storage, methanation, biofuel and industrial or manufacturing applications. The Joint Utilities shall address how to prioritize CCS/U in their SBPM.

The GHG and environmental benefit of CCS/U shall be added to the CI score, as CRNG recommends, to determine production facility life cycle carbon emissions and create an incentive for CCS/U projects.

3.3.3.8. Core Transport Agent Requirements

We agree with the Staff Proposal, as well as CRNG, Shell, BAC, and the Joint Utilities that CTAs should be required to meet or exceed biomethane procurement levels of the Joint Utilities. Ideally, legislation should be enacted requiring CTAs to procure biomethane at the same rate as the Joint Utilities, similar to legislation enacted in 2005 that requires Community Choice Aggregators to comply with the RPS compliance obligations established by the Commission. The Office of Governmental Affairs should work with the Legislature and stakeholders to achieve this objective.

We decline to consider in this proceeding whether a nonbypassable charge for Joint Utilities' incremental biomethane procurement costs should be imposed on CTA customers as an interim measure. Instead, we intend to explore this issue in a new ratesetting proceeding that will explore the appropriateness of adopting a nonbypassable charge for noncore unbundled gas distribution system customers (*see* Section 3.3.1).

3.3.3.9. Soil Amendment Requirements

We agree with the Staff Proposal, as well as CRNG, AECA, and Dairy Cares, that the Joint Utilities should be required to prioritize biomethane procurement from facilities that commit to turning their waste byproduct into soil amendment such as biochar. However, we modify the Staff Proposal recommendation to expand the desirable uses of such waste products beyond converting them into soil amendments to include any GHG-reducing use. To the extent that a biomethane producer can demonstrate that their waste byproduct has had any perfluoroalkyl or polyfluoroalkyl substances (PFAS)[23] removed from it, that producer shall be given added prioritization. The Joint Utilities shall address how to prioritize procurement from such facilities in their SBPM.

3.3.3.10. Pilot Projects for Converting Biomass to Biomethane

We adopt the Staff Proposal's recommendation requiring PG&E and SoCalGas to submit applications for pilot projects that can convert woody biomass into bio-SNG. However, we modify the Staff Proposal recommendation per BAC's request to allow PG&E and SoCalGas to propose more than one pilot project each and to include agricultural waste and urban wood waste diverted from landfills to support wildfire prevention and SLCP reduction. We authorize

[23] *See*: https://www.epa.gov/pfas.

PG&E and SoCalGas to propose procuring bio-SNG from forest, agricultural, and urban wood waste pyrolysis and gasification projects using methanation. We also direct them to explore coordinating the procurement efforts and strategic placement with local and state authorities, including the Department of Conservation that was authorized by SB 155 (Committee on Budget and Fiscal Review, 2021) to dedicate $50 million for similar purposes. We adopt additional recommendations from the Staff Proposal: (1) project cost should include pipeline extensions to the pilot facilities, (2) pipeline extensions should facilitate future potential extensions for additional projects, and (3) the pilots should propose methods for using CO_2 in CCS/U projects rather than venting to the atmosphere.

We recognize that both the commodity cost and interconnection costs for these pilot projects could be considerable if not otherwise mitigated. To help achieve the GHG and criteria air pollutant emission reductions associated with procuring bio-SNG, we direct the Joint Utilities to collectively set aside $40 million from their 2022 Cap-and-Trade allowance proceeds so that additional funding is available to offset pipeline build-out costs and related expenses associated with the pilot projects. This funding complies with all applicable CARB regulations governing the use of allowance proceeds. This approach is also consistent with both AB 3187 (Grayson, 2018) and Pub. Util. Code Section 784.2, which directs the CPUC to explore options for furthering the goals of Pub. Util. Code Section 399.24 to promote the in-state production and distribution of biomethane and consider whether to allow recovery in rates of the costs of interconnecting biomethane projects. These funding set-asides will reduce the Climate Credit refunded to gas customers in 2022 by a small amount, but the average residential customer of each of the Joint Utilities will still receive

a Climate Credit that will cover at least the full amount of costs that the gas IOUs collected from them for Cap-and-Trade program compliance costs.

As noted previously in D.20-12-031, multiple parties to this proceeding have requested that the CPUC increase funding for biomethane pipeline interconnection projects using gas IOU Cap-and-Trade allowance proceeds. Conclusion of Law 9 of D.20-12-031 found that the CPUC may use Cap-and-Trade allowance proceeds to increase funding for biomethane project interconnection incentives.

Consistent with past precedent established in both D.20-03-027 and D.20-12-031, the additional $40 million set-aside of Cap-and-Trade allowance proceeds shall be allocated consistent with each IOU's respective percentage of their combined CARB allocation of Cap-and-Trade allowances, which shall be as follows:

- SoCalGas: $19,704,000 (49.26 percent of $40 million)
- PG&E: $16,936,000.00 (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)

The full annual allocation for each of the Joint Utilities shall be deducted from the 2022 Climate Credit. Each of the Joint Utilities shall file a Tier 1 Advice Letter within 15 days of the date of the approval of this decision revising their natural gas 2022 Climate Credit amount to reflect the reduction mandated by this decision. 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, subsequently modified by D.20-03-027 and then D.20-12-031) to include below line 9c a new line numbered 9d and titled "Biomethane Interconnection Costs." This line shall record each gas utility's share of the $40 million set-aside, 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 RNG Incentive Costs minus Biomethane Interconnection Costs. In order to reflect this change, the Joint Utilities shall 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 + Line 9d)." This requirement shall apply to all future filings seeking approval of the natural gas Climate Credit amount for each of the Joint Utilities until or unless the CPUC decides otherwise.

Each of the Joint Utilities shall separately file a Tier 1 Advice Letter within 15 days of the date of the approval of this decision establishing a new balancing account to track all Cap-and-Trade allowance proceeds set aside pursuant to this decision, as well as any interest accrued on those proceeds.

SDG&E and/or SWG, as wholesale customers of SoCalGas, may direct their respective share of allowance proceeds collected pursuant to this decision to be used to offset pilot project costs in SoCalGas service territory if SDG&E or SWG procure a portion of the biomethane produced from that facility or facilities. Any of the Joint Utilities may request to return unused allowance proceeds to their residential customers in the form of the next Climate Credit if they anticipate those proceeds will go unspent. A gas IOU wishing to return allowance proceeds to its residential customers shall submit a Tier 2 Advice Letter seeking such approval from the CPUC. Any unspent allowance proceeds shall be returned to ratepayers within 10 years of the date of adoption of this decision.

3.3.4. Adopted Actions on Issues Not Addressed by the Staff Proposal

3.3.4.1. Methane Leaks

The Joint Utilities shall require biomethane producers to include methane leak detection in life cycle CI accounting via a modified GREET model. We agree with party comments that methane leaks in the production process or at the point of interconnection should be monitored and factored into the life cycle analysis for carbon emissions.

3.3.4.2. Integration With the Voluntary Renewable Natural Gas Tariff

We authorize the gas IOUs participating in the VRNGT program – SoCalGas and SDG&E – to allow all customers that sign up for the VRNGT to contract for more incremental biomethane in excess of SB 1440 targets. Those costs shall be recovered via the terms of the VRNGT program.

3.3.4.3. Compressed Natural Gas Fueling Stations

We decline to rule on the 2018 LCFS pilot arrangement for CNG fueling because this request is outside the scope of this decision.

3.3.4.4. Renewable Thermal Certificate Tracking

We require biomethane producers to track volumetric injections into pipelines through the M-RETS platform and/or another platform identified in the workshop to be hosted no later than one month from the date of adoption of this decision (*see* Section 3.3.1), even though the short-term target is not a volumetric target. The data collected will support our efforts to calculate potential gas production based on tons of organic waste. There are numerous studies that estimate technical and economic potential of feedstocks by weight, but relatively less data based on the correlation between tons and volumes of gas

produced in a variety of production facilities that range in size, geography and gas production conditions. Transparent tracking of short-term volumes of biomethane will help the Commission review and/or modify medium-term targets.

3.3.4.5. Contract Duration

Procurement contracts should be for a minimum of 10 years and a maximum of 15 years. We consider this a reasonable range that provides flexibility while also providing security in the form of long-term contracts.

4. Comments on Proposed Decision

The proposed decision of Commissioner Rechtschaffen 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 _____.

5. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner in this proceeding and Karl J. Bemesderfer is the assigned Administrative Law Judge.

Findings of Fact

1. Targets or goals shall be consistent with the organic waste disposal reduction targets specified in Section 39730.6 of the Health and Safety Code and the regulations adopted pursuant to Section 42652.5 of the Public Resources Code to achieve those targets.

2. California Department of Resources Recycling and Recovery estimates a need for eight million tons of additional organic waste processing capacity to meet 2030 Senate Bill 1383 goals.

3. California Air Resources Board estimates in its 2017 Scoping Plan that California Department of Resources Recycling and Recovery's 2030 organic

waste diversion goals may result in avoiding 4 million metric tons of carbon dioxide equivalent in greenhouse gas emissions.

4. Four million metric tons of carbon dioxide equivalent converts to approximately 72.8 billion cubic feet of combusted methane.

5. Methane is a potent short-lived climate pollutant.

6. Biomethane is methane produced by bacterial activity in organic material.

7. The primary source of methane for use as a fuel is gas wells.

8. Biomethane and methane from gas wells are chemically identical.

9. Capturing biomethane and substituting it for methane from gas wells reduces the amount of methane entering the atmosphere.

10. Both well gas and biomethane contain impurities that must be removed to meet pipeline gas quality standards.

11. The total cost of a unit of methane from any source includes the direct cost of locating, capturing, treating, transporting and delivering the gas to an end user, together with the costs of environmental impacts borne by the residents of the areas where the gas is located, captured, treated, transported and delivered.

12. California Department of Resources Recycling and Recovery estimates a shortfall for eight million tons of additional organic waste processing capacity to meet 2030 Senate Bill 1383 goals.

13. Combustion of biomethane and methane creates criteria air pollutants.

14. The Cap-and-Trade allowance proceeds set aside in this decision shall be used to reduce statewide greenhouse gas emissions by funding the agricultural waste and urban wood waste diverted from landfills pilot programs to support wildfire prevention and short-lived climate pollution reduction.

Conclusions of Law

1. Senate Bill 1440 gives the California Public Utilities Commission authority to adopt biomethane procurement targets or goals.

2. Senate Bill 1383 requires California to reduce emissions of methane by 40 percent below 2013 levels by 2030.

3. To meet the state's methane emission reduction goals, biomethane should be substituted for well gas whenever the total cost of a unit of biomethane is equal to or less than the total cost of a unit of well gas.

4. Biomethane may be substituted for well gas even if the total cost of a unit of biomethane exceeds the total cost of a unit of well gas if the substitution is necessary to enable the state to meet its methane emission reduction goals.

5. To meet the state's methane emission reduction goals, the Commission should establish biomethane procurement targets, timetables and collateral requirements for the state's investor-owned gas utilities.

6. Biomethane procurement requirements should maximize the use of energy from renewable sources.

7. Biomethane procurement requirements should include minimizing the use of equipment powered by fossil fuels.

8. Biomethane procurement requirements should prioritize obtaining biomethane from organic waste diverted from landfills.

9. Biomethane procurement requirements should ensure that procurement programs are cost-effective.

10. Biomethane procurement requirements may include any other provisions necessary to ensure the achievement of the state's methane emission reduction goals.

11. Biomethane procurement strategies should maximize benefits for environmental justice communities.

12. Decision 20-12-031 found that the Commission may use Cap-and-Trade allowance proceeds to increase funding for the biomethane monetary incentive program to reduce statewide greenhouse gas emissions under Section 95893 of the Cap-and-Trade Regulation and Senate Bill 1477.

O R D E R

IT IS ORDERED that:

1. Cost-Effectiveness Workshop.
   - Energy Division shall host a workshop on cost-effectiveness within one month of the effective date of this decision. The workshop agenda shall be based on the discussion in Section 3.3.1 of this decision.
   - Within three months of the workshop, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) shall include results of the workshop and address feedback received at the workshop in Tier 2 Advice Letters establishing a Standard Biomethane Procurement Methodology and their respective procurement plans.
   - Joint Utilities shall include in their Standard Biomethane Procurement Methodology a provision giving higher priority to biomethane producers that demonstrate that their waste byproduct has had perfluoroalkyl or polyfluoroalkyl substances removed from it.
   - The Commission shall evaluate the Standard Biomethane Procurement Methodology according to the criteria identified in the workshop.
2. The Commission's Energy Division will process individual contracts to procure biomethane through a three-tier advice letter approval process:

- Tier 1 for contract prices below $17.70/MMBtu
- Tier 2 for contract prices between $17.70 and $26/MMBtu
- Tier 3 for contract prices $26/MMBtu and above.

3. The short-term target for organic waste diverted annually from landfills is eight million tons. Each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall be responsible for diverting a percentage of the eight million tons of organic waste according to each of their respective Cap-and-Trade allowance shares: Southern California Gas Company 49.26 percent, Pacific Gas and Electric Company 42.34 percent, San Diego Gas & Electric Company 6.77 percent, and Southwest Gas Corporation 1.63 percent.

4. The medium-term target for each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation is to procure 15 percent of its own share of 2020 annual core customer natural gas demand (totaling approximately 88 billion cubic feet of biomethane and bio-synthetic natural gas per year) by 2030. The Commission will review this target in 2025 and provide additional analysis on technical and economic feasibility.

5. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) are allowed unlimited forward banking of excess procurement on the following terms:

- Procurement in any year shall be applied first to that year's annual procurement target, with any excess procurement then being used to make up a prior year's deficit, or banked for future use, as described above.

- Joint Utilities are allowed to carry over an annual deficit of 25% to the next three years without explanation, as described above.
- Joint Utilities are allowed to trade excess supplies among themselves.

6. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation are allowed to procure on behalf of each other.

7. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) shall start procurement as soon as possible, using a preliminary cost-effectiveness test developed in the workshop, described in Ordering Paragraph 1, that estimates the short-lived climate pollutant reduction and life cycle carbon emissions until a carbon intensity score is established and while the modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model is being developed.

8. Within 30 days of the effective date of this decision, the Commission shall create a procurement advisory group similar to the one established in the Voluntary Renewable Natural Gas Tariff Decision 20-12-022. Participants in the procurement advisory group will not be allowed to claim intervenor compensation.

9. Livestock biomethane procurement contracts are excluded from the Senate Bill 1440 biomethane procurement program.

10. If the Low Carbon Fuel Standard is modified to exclude dairy biomethane, then the Commission grants Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas

Corporation the option to procure livestock biomethane for meeting medium-term Senate Bill 1440 targets and beyond.

11. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) shall each file their Renewable Gas Procurement Plans as Tier 3 Advice Letters, served on the service list in this proceeding, within six months of Commission approval of the Tier 2 Advice Letters establishing a Standard Biomethane Procurement Methodology. Concurrent with the filing of the Tier 3 Advice Letter, the Joint Utilities shall each update their currently required annual reports to include details of actual biomethane procurement levels, ratepayer bill impacts, and incremental capital infrastructure and/or operations and maintenance costs for the prior year compared to the estimated levels that were approved in their respective Renewable Gas Procurement Plans.

12. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) shall include in the Standard Biomethane Procurement methodology the following biomethane procurement practices:

- Joint Utilities shall include environmental assessments and social justice impacts as part of their biomethane procurement practices.
- Joint Utilities shall take into consideration the ways in which modifications to a wastewater treatment plant or landfill to increase biomethane production would contribute to or detract from economic, health, and non-energy benefits for local communities.

13. Within 90 days of the effective date of this decision, each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas &

Electric Company, and Southwest Gas Corporation shall file a Tier 1 Advice Letter with a uniform update in their respective tariffs for the Standard Renewable Gas Interconnection Tariff to include an interim Trigger Limit of 0.03 mole percent carbon monoxide.

14. $One million over three years shall be set aside for a collaboration between the Commission and the Office of Environmental Health Hazard Assessment to contract with a research institution and/or private company with expertise in bio-synthetic natural gas research for a study regarding health-based concentration limits for constituents of concern, namely trace toxic substances including carbon monoxide. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall reimburse the Commission the contract cost of such research up to $1 million from each respective utility's public purpose program funds in proportion to each gas investor-owned utility's Cap-and-Trade allowance share defined in Decision 20-12-031 as follows: Southern California Gas Company 49.26 percent, Pacific Gas & Electric Company 42.34 percent, San Diego Gas & Electric Company 6.77 percent, and Southwest Gas Corporation 1.63 percent.

15. Within 30 days of the effective date of this decision, each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall file a Tier 1 Advice Letter with a uniform update in their respective tariffs for the Standard Renewable Gas Interconnection Agreement to require a hydrogen sulfide limit in gathering lines of 10 parts per million.

16. Within 30 days of the effective date of this decision, Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric

Company, and Southwest Gas Corporation shall file a Tier 1 Advice Letter updating the biomethane Incentive Reservation Form to include an agreement to limit hydrogen sulfide in gathering lines to 10 parts per million.

17. Any contract between a project developer and an investor-owned utility shall specify how tipping fees may modify contract terms. Energy Division staff shall ensure that each contract meets this requirement prior to approval.

18. All biomethane procured through this program must be from facilities that commit to use near-zero emissions and zero-emissions vehicles prospectively. The greenhouse gas reduction and environmental benefit of such vehicles shall be factored in the carbon intensity score.

19. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall prioritize procurement of biomethane from production facilities that agree not to increase on-site generation of electricity using their own biogas beyond current generation levels unless that biogas is upgraded to biomethane that generates electricity through non-combustion technology such as an on-site fuel cell stack.

20. The Commission shall prioritize projects that use carbon capture and storage or use technology. The greenhouse gas reduction and environmental benefit of carbon capture and storage or use shall be included in the carbon intensity score.

21. The Commission shall prioritize biomethane procurement projects that use waste byproducts, including biosolids, sewage sludge, digestate, and biochar for any greenhouse gas-reducing use rather than putting them in landfills.

22. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall file an application no later than January 1, 2023, proposing at least two woody biomass

gasification projects focused on methanation and coordinate such gasification projects and strategic placement with the pilot projects authorized for the Department of Conservation by Senate Bill 155. The project cost shall include pipeline extensions to the pilot facilities. Pipeline extensions should facilitate future potential extensions for additional projects and the pilots should propose methods for using carbon dioxide in carbon capture and storage or use projects rather than venting it to the atmosphere.

23. Natural Gas 2022 Climate Credit:

- Within 15 days of the effective date of this decision, each of Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation (collectively, Joint Utilities) shall file a Tier 1 Advice Letter revising their natural gas 2022 Climate Credit amount to reflect the reduction mandated by this decision. The Joint Utilities' advice letter filings shall modify the table format established by Decision (D.) 15-10-032 (*i.e.*, Table C of Appendix A of that decision, subsequently modified by D.20-03-027 and then D.20-12-031) to include below line 9c a new line numbered 9d and titled "Biomethane Interconnection Costs." This line shall record each gas utility's share of the $40 million set-aside, as established by this decision. Line 10 of Table C of Appendix A of D.15-10-032 shall also be modified to equal the Subtotal Allowance Proceeds minus Outreach and Admin Expenses minus Senate Bill 1477 Compliance Costs minus Renewable Natural Gas Incentive Costs minus Biomethane Interconnection Costs. In order to reflect this change, the Joint Utilities shall further modify the template for Table C by changing the description of Line 10 of Table C of Appendix A of D.15-10-032 to "Net GHG Proceeds Available for Customer Returns ($) (Line 8 + Line 9 + Line 9b + Line 9c + Line 9d)." This requirement shall apply to all future filings seeking approval of the natural gas Climate Credit amount for each of the Joint Utilities until or unless the Commission decides otherwise.

- Within 15 days of the effective date of this decision, each of the Joint Utilities shall file a Tier 1 Advice Letter establishing a new balancing account to track all Cap-and-Trade allowance proceeds set aside pursuant to this decision, as well as any interest accrued on those proceeds. Following the first set-aside deducted from the 2022 Climate Credit, each of the Joint Utilities' annual set-aside shall be deposited in quarterly installments equal to one-quarter of the annual established allocation for each gas investor-owned utility. Those quarterly installments shall be set aside on or before March 1, June 1, September 1, and December 1 to follow California Air Resources Board's quarterly auctions in February, May, August, and November. Each of the Joint Utilities may delay their first quarterly set-aside from no later than March 1, 2022 to no later than June 1, 2022 to provide adequate time for the filing and approval of the new balancing account.
- If either San Diego Gas & Electric Company or Southwest Gas Corporation procures biomethane from agricultural waste and urban wood waste pilot projects located in Southern California Gas Company's service territory, they may use their respective shares of allowance proceeds collected pursuant to this decision to offset the pilot project costs. Any of the Joint Utilities may request Commission approval to return unused allowance proceeds to their residential customers in the form of the next Climate Credit if they anticipate those proceeds will not be spent. A gas investor-owned utility wishing to return allowance proceeds to its residential customers shall submit a Tier 2 Advice Letter seeking such approval from the California Public Utilities Commission.
- Any unspent Cap-and-Trade allowance proceeds shall be returned to ratepayers in the Climate Credit within 10 years of the effective date of this decision.

24. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall

require biomethane producers to include methane leak detection in the Standard Biomethane Procurement Methodology life cycle carbon intensity accounting in the modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model.

25. Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southwest Gas Corporation shall require biomethane producers to track volumetric injections of biomethane into pipelines through the Midwest Renewable Energy Tracking System (M-RETS) platform or other platform resulting from the workshop in Ordering Paragraph 1 above.

26. Southern California Gas Company and San Diego Gas & Electric Company are authorized to allow all customers that sign up for the Voluntary Renewable Natural Gas Tariff program to contract for biomethane in excess of Senate Bill 1440 targets. Those costs should be recovered via the terms of the program.

27. The 2018 Low Carbon Fuel Standard pilot arrangement for renewable natural gas fueling is outside the scope of this decision.

28. The Commission will open a ratesetting proceeding no later than January 1, 2023, to consider distributing above market biomethane procurement costs and nonbypassable charges to noncore customers.

29. The Office of Governmental Affairs shall work with the Legislature and stakeholders for legislation requiring core transport agents to procure biomethane at the same rate as the Joint Utilities.

30. Biomethane procurement contracts shall be for a minimum of 10 years and a maximum of 15 years.

31. This proceeding remains open to address the remaining scoped issues.

This order is effective today.

Dated _____, at San Francisco, California.

Attachment 1:
Glossary of Acronyms

Senate Bill (SB) 1440 Glossary of Acronyms

Bcf	Billion Cubic Feet
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCS	Carbon Capture and Storage
CCS/U	Carbon Captures and Storage or Use
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CTA	Core Transport Agent
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
H_2S	Hydrogen Sulfide
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
LCFS	Low Carbon Fuel Standard
MMBtu	Million British Thermal Units
M-RETS	Midwest Renewable Energy Tracking System
MSCF	Thousand Standard Cubic Feet
NZE	Near-Zero Emissions
OSHA	Occupational Safety and Health Administration
RGPP	Renewable Gas Procurement Plan
RPS	Renewables Procurement Standard
SBPM	Standard Biomethane Procurement Methodology

SLCP	Short-Lived Climate Pollutant
SNG	Synthetic Natural Gas
SRGIA	Standard Renewable Gas Interconnection Agreement
SRGIT	Standard Renewable Gas Interconnection Tariff
SRGPM	Standard Renewable Gas Procurement Methodology
VRNGT	Voluntary Renewable Natural Gas Tariff
WWTP	Wastewater Treatment Plant
ZE	Zero Emission

(END OF APPENDIX A)