

Application: A.25-10-008
Witnesses: James Lucas and Dr. Matthew Summers
Chapter: 3
Exhibit: SCG-03

**PREPARED REBUTTAL TESTIMONY OF
JAMES LUCAS AND DR. MATTHEW SUMMERS
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY**

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

April 10, 2026

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**PREPARED REBUTTAL TESTIMONY OF
JAMES LUCAS AND DR. MATTHEW SUMMERS
CHAPTER 3**

I. PURPOSE

The purpose of our prepared rebuttal testimony on behalf of Southern California Gas Company (SoCalGas) is to address intervenor testimony from the Public Advocates Office (Cal Advocates), Sierra Club, Small Business Utility Advocates (SBUA), and Bioenergy Association of California (BAC), dated March 16, 2026, regarding the gasification pilot project consistent with Senate Bill (SB) 1440 (SB 1440 Pilot Project), as proposed in the Application of SoCalGas Proposing Woody Biomass Pilot Project (Application). This rebuttal testimony responds to the comments and claims raised by the intervenors and is organized according to the issues identified in the Assigned Commissioner’s Scoping and Ruling for the SB 1440 Woody Biomass Pilot.¹

II. SCOPED ISSUE 1: THE PROPOSED SB 1440 PILOT PROJECT IS CONSISTENT WITH THE COMMON USAGE OF THE TERM “PILOT PROJECT” (WITNESS: JAMES LUCAS)

SoCalGas agrees with the direct testimony of SBUA² and BAC³ that the proposed SB 1440 Pilot Project falls under the definition of a pilot, as described in Ordering Paragraph 43 of Decision (D.)22-02-025 and consistent with the common usage of the term “pilot project.” Neither Cal Advocates nor Sierra Club discuss the common usage of the term “pilot project” in their respective testimonies.

In December 2017, the Commission issued D.17-12-004 (SB 1383 Decision)⁴ establishing the necessary framework to direct SoCalGas and PG&E to implement dairy biomethane pilot projects (SB 1383 Pilot Projects). The SB 1383 Pilot Projects were structured as first-of-their-kind pilot projects, undertaken on a limited basis to evaluate, amongst other items, technical performance, environmental benefits, costs, long term viability, and to generate data that could inform future program design or policy development. While each of the

¹ Assigned Commissioner’s Scoping and Ruling for the SB 1440 Woody Biomass Pilot, *available at:* <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K902/596902616.PDF>.

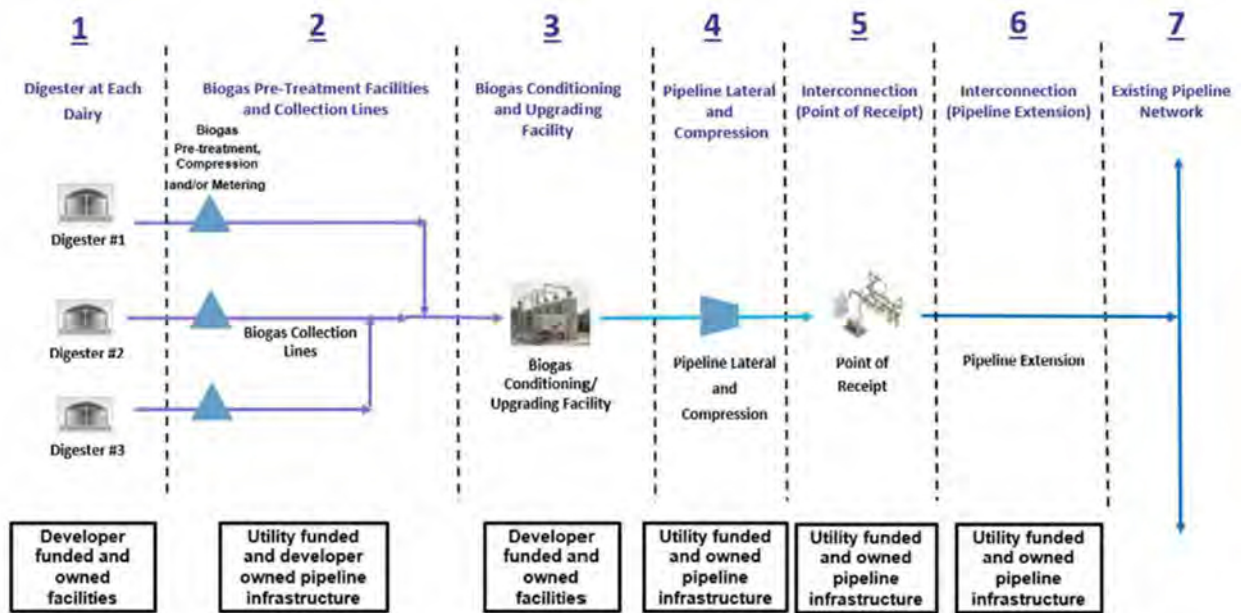
² Direct Testimony of Ted Howard on Behalf of Small Business Utility Advocates at 3.

³ Testimony of Julia Levin Regarding the Application of Southern California Gas Company Proposing Woody Biomass Pilot Project at 6.

⁴ D.17-12-004, Decision Establishing Implementation and Selection Framework to Implement the Dairy Biomethane Pilots Required By Senate Bill 1383 (December 14, 2017), *available at:* <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF>.

1 technologies incorporated in project Lanes 1 through 6⁵ (Figure 1) was commercially available in
 2 the United States, at the time SB 1383 was enacted in 2016, there were to SoCalGas's
 3 knowledge, no dairy cluster projects operating domestically that integrated these commercially
 4 available technologies into an integrated system capable of producing RNG and interconnecting
 5 with a utility pipeline. It was this novel integration of proven technologies at a clustered dairy
 6 scale that warranted treatment of these projects as pilot projects.

7 **Figure 1: Dairy Biomethane Pilot Primary Components⁶**



8
 9
 10 As stated in the Chapter 2 Corrected Revised Direct Testimony of Lucas/Summers
 11 (Lucas/Summers Testimony), SoCalGas successfully applied the SB 1383 Pilot Project
 12 framework to interconnect four dairy pilot projects to the SoCalGas pipeline system between
 13 2021 and 2022.⁷ Because the Commission approved framework and evaluation process proved
 14 effective for the SB 1383 Pilot Projects, SoCalGas adopted a similar framework and approach

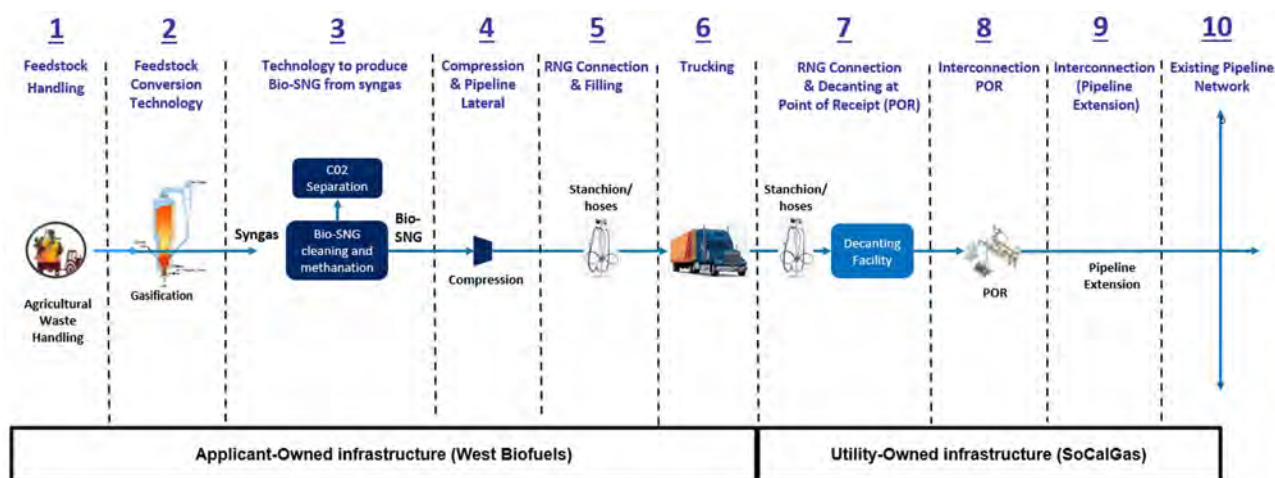
⁵ A standard biomethane methodology was established to define how the SB 1383 Dairy Pilot Selection Committee and utilities approach and evaluate biomethane projects. A core structural element is a “lanes” framework that organizes various options across different feedstocks, technologies, and delivery pathways.

⁶ Lucas/Summers Testimony at JLMS-3.

⁷ *Id.* at JLMS-2.

1 for the evaluation and selection of the SB 1440 Pilot Project.⁸ Consistent with the SB 1383 Pilot
 2 Projects, the SB 1440 Pilot Project is likewise structured as a first-of-its-kind pilot. While the
 3 technologies incorporated across project Lanes 1 through 9 (Figure 2) are commercially
 4 available, their integration into a single, commercial-scale system capable of converting woody
 5 biomass into biomethane and interconnecting with a utility pipeline has not, to SoCalGas’s
 6 knowledge, been achieved in the United States. Prior efforts have largely been limited to
 7 demonstration or small-scale projects.

8 **Figure 2**



9
 10 The combined use of gasification, syngas cleaning, methanation, and pipeline- injection
 11 technologies continue to evolve and requires extended operational experience to inform large-
 12 scale deployment. This need is particularly acute given the growing volumes of available woody
 13 biomass and the importance of developing environmentally beneficial management alternatives.
 14 As with the SB 1383 Pilot Projects, this novel integration of proven technologies using woody
 15 biomass as the feedstock warrants treatment of the SB 1440 Pilot Project as a “pilot project.”

16 **III. SCOPED ISSUE 2: SOCALGAS’S PROPOSAL TO FUND LANES 7, 8, AND 9,**
 17 **ALONG WITH LANES 3, 4 AND 5 MEETS THE REQUIREMENTS OF D.22-02-**
 18 **025 (AT 46) BECAUSE THESE COSTS WILL “OFFSET PIPELINE BUILD-OUT**
 19 **COSTS AND RELATED EXPENSES ASSOCIATED WITH THE PILOT**
 20 **PROJECTS” (WITNESS: JAMES LUCAS)**

21 SBUA and BAC intervenor testimonies conclude that SoCalGas’s proposed use of the
 22 \$19.704 million in Cap-and-Invest (formerly referred to as “Cap-and-Trade”) funds to support

⁸ *Id.*

1 project Lanes 7 through 9 is consistent with D.22-02-025. SBUA is “not aware of any evidence
2 which would indicate that SCG’s proposed use of the \$19.704 million Cap-and-[Invest] funds is
3 not compliance with D.22-02-025”.⁹ BAC similarly concludes that Lanes 7, 8, and 9 represent
4 the core interconnection equipment that is central to pipeline build-out costs, and that the
5 application of any excess funds to Lanes 3, 4 and 5 is likewise consistent with D.22-02-025
6 because those lanes constitute “related expenses associated with the pilot projects.”¹⁰ Neither Cal
7 Advocates nor the Sierra Club discusses or addresses SoCalGas’s proposed funding approach for
8 the various lanes of the SB 1440 Pilot Project.

9 Moreover, through D.15-06-029 (establishing the Biomethane Monetary Incentive
10 Program) and D.17-02-004 (authorizing the SB 1383 Pilot Projects), the Commission has clearly
11 established precedent governing the types of pipeline infrastructure costs eligible for utility
12 funding. As stated in the Lucas/Summers Testimony, SoCalGas utilized a framework for
13 assessing and selecting the SB 1440 Pilot Project that is similar with the framework applied to
14 the SB 1383 Dairy Pilot Projects.¹¹ As such, SoCalGas proposes in this Application to cover
15 costs required to (1) compress Bio-SNG (Lane 4), and (2) inject the compressed Bio-SNG into
16 the existing pipeline system (Lanes 7-9).¹² These categories are similar to the Commission-
17 approved framework established for SB 1383 Pilot Projects,¹³ under which such costs were
18 designated as eligible for utility funding.¹⁴ Figure 2 illustrates and defines the high-level
19 components of the proposed SB 1440 Pilot Project, including the production of Bio-SNG and its
20 interconnection with the utility pipeline.¹⁵

21 As detailed in the Lucas/Summers Testimony, the statewide biomethane monetary
22 incentive program is structured to provide funding support for costs associated with facilities

⁹ SBUA Testimony at 4.

¹⁰ BAC Testimony at 7-8.

¹¹ Lucas/Summers Testimony at JLMS-2.

¹² SoCalGas classifies Lane 7 as utility-owned infrastructure necessary for the interconnection and injection of biomethane into the pipeline. Lane 7 infrastructure costs do in fact “offset pipeline build-out costs and related expenses associated with the pilot projects” by allowing for a significantly shorter pipeline extension (Lane 9).

¹³ The proposed SB 1440 Pilot Project framework incorporates Lane 7.

¹⁴ D.17-02-004, Appendix A at 1.

¹⁵ Lucas/Summers Testimony at JLMS-7.

1 downstream of the biomethane interconnector’s processing plants used for delivering biomethane
2 into the utility or third-party pipeline system.¹⁶ Similar with the approaches adopted for the SB
3 1383 Pilot Projects and the biomethane monetary incentive program, SoCalGas is proposing to
4 use Cap-and-Invest funding to offset SB 1440 Pilot Project infrastructure costs associated with
5 Lanes 4 and 7–9.

6 Additionally, D.22-02-025 directs that Cap-and-Invest funding be used to “offset pipeline
7 build-out costs and related expenses associated with pilot projects.”¹⁷ If Cap-and-Invest funds
8 remain after covering the aforementioned infrastructure costs (Lanes 4, 7, 8, and 9), SoCalGas
9 proposes to apply the remaining funds to support costs associated with West Biofuel’s Bio-SNG
10 interconnection and fueling facilities (Lane 5), as well as methanation and carbon dioxide
11 removal (CDR) facilities (Lane 3).¹⁸ These facilities constitute necessary infrastructure to
12 produce biomethane for delivery into SoCalGas’s pipeline system and to capture associated CO₂
13 emissions. Accordingly, they fall squarely within the category of “related expenses” associated
14 with the pilot projects contemplated by D.22-02-025.

15 **IV. SCOPED ISSUE 3: THE PROPOSED SB 1440 PILOT PROJECT MEETS THE**
16 **REQUIREMENTS OF D.24-12-032 (WITNESS: JAMES LUCAS)**

17 As stated in D.24-12-032,¹⁹ and consistent with the direction provided in D.22-02-025, if
18 SoCalGas elects to file an application proposing at least one woody biomass gasification pilot project
19 focused on conversion of woody biomass to biomethane, the project:

- 20 • May focus on either forest or agricultural waste, as best serves its interests and the
21 interests of its customers;
- 22 • Should have its procurement efforts and strategic placement coordinated with
23 local and state authorities, including the Department of Conservation;
- 24 • Must include costs for pipeline extensions to the pilot facilities in the project
25 costs;
- 26 • Should facilitate future potential extensions for additional projects;

¹⁶ Lucas/Summers Testimony at JLMS-5 and 6.

¹⁷ D.22-02-025 at 46.

¹⁸ Lucas/Summers Testimony at JLMS-18.

¹⁹ D.24-12-032 at 6-7.

- 1 • Should propose methods for using carbon dioxide in carbon capture and storage
- 2 or use projects rather than venting carbon dioxide to the atmosphere;
- 3 • Should test technologies that are capable of extension and have significant
- 4 potential to increase the renewable natural gas supply in the long term; and
- 5 • Must study and report fugitive methane, pollutant, and particulate matter
- 6 emissions and emissions reduction or elimination methods in the gasification or
- 7 pyrolysis process, the methanation process, and pipeline infrastructure.

8 As described in the Lucas/Summers Testimony, SoCalGas addresses each of these seven
9 criteria and provides supporting justification and evidence demonstrating the SB 1440 Pilot
10 Project satisfies the criterion.²⁰

11 Both BAC and SBUA agree that the SB 1440 Pilot Project meets each of these eligibility
12 requirements. In its testimony, BAC describes each requirement and explains how the SB 1440
13 Pilot Project satisfies these established criteria at Commission direction.²¹ SBUA similarly states,
14 “SCG filed a new application proposing a woody biomass pilot project, I believe the Company
15 complies with the Decision.”²² Sierra Club does not specifically address any of the seven listed
16 SB 1440 Pilot Project eligibility requirements in its testimony.

17 By contrast, Cal Advocates asserts that the project does not comply with D.22-02-025,
18 claiming that “the Commission ordered SoCalGas to include pipeline extensions to the pilot
19 facilities. SoCalGas does not satisfy this requirement because it does not demonstrate direct
20 pipeline connections or extensions from the West Biofuel facility to SoCalGas’s facilities.”²³ Cal
21 Advocates’ argument rests on an unsupported assumption that the term “pipeline extension”
22 refers exclusively to a pipeline segment connecting the West Biofuel facility directly to
23 SoCalGas’s interconnection facility.

24 As explained in the prepared Lucas/Summers Testimony, SoCalGas evaluated and
25 selected the SB 1440 Pilot Project using a framework similar to that applied to the SB 1383 Pilot
26 Projects.²⁴ Importantly, D.17-12-004 explicitly defines the term “pipeline extension” and

²⁰ Lucas/Summers Testimony at JLMS-7-9.

²¹ BAC Testimony at 8-9.

²² SBUA Testimony at 4-5.

²³ Cal Advocates Testimony at 1-3.

²⁴ Lucas/Summers Testimony at JLMS-2.

1 clarifies that a pipeline extension is not a mandatory or inherent component of pilot project
2 infrastructure:

- 3 • Appendix A of D.17-02-004 sets forth the Dairy Biomethane Pilot
4 Implementation Framework, identifies the categories of infrastructure eligible for
5 funding, and defines a pipeline extension as infrastructure that “delivers
6 biomethane from the point of receipt to the utility’s existing gas pipeline
7 system.”²⁵ This definition establishes both the definition and functional role of a
8 pipeline extension. Consistent with this precedent, SoCalGas has included the
9 pipeline extension costs within the overall project costs for the SB 1440 Pilot
10 Project. Further, Figure 1 in D.17-02-004²⁶ visually depicts the location of the
11 pipeline extension, situated between the point of receipt and the existing utility
12 pipeline system, reinforcing that this portion of the infrastructure constitutes the
13 pipeline extension.
- 14 • Cal Advocates further construes the requirement in D.24-12-032 that “the project
15 cost shall include pipeline extensions to the pilot facilities” as mandating a
16 pipeline extension. The decision, however, imposes no such requirement. Rather,
17 it requires that if a pipeline extension is needed, its costs be included in the total
18 project cost. Indeed, in D.17-02-004, the Commission expressly acknowledged
19 that a pipeline extension may not be required, explaining that “[i]f a pipeline
20 extension is necessary, it provides a tie in from the point of receipt to the existing
21 pipeline network.”²⁷ The Commission’s use of the conditional term “if,” confirms
22 that a pipeline extension is not an inherent or mandatory component of the pilot
23 project infrastructure.

²⁵ D.17-02-004, Appendix A at 1.

²⁶ *Id.* at 16.

²⁷ *Id.* Appendix A at 9.

1 **V. SCOPED ISSUE 4: THE PROPOSED SB 1440 PILOT PROJECT COMPLIES**
2 **WITH THE APPLICABLE CALIFORNIA AIR RESOURCES BOARD (CARB)**
3 **REGULATIONS, INCLUDING BUT NOT LIMITED TO 17 CCR §§95893(D)(3),**
4 **(D)(5) AND (D)(8)**

5 SoCalGas has demonstrated that the SB 1440 Project complies with applicable CARB
6 regulations, including 17 CCR §§95893(d)(3), (d)(5) and (d)(8). In its testimony, BAC agrees
7 that the proposed pilot project is consistent with 17 CCR §§95895(d)(3) and (d)(5).²⁸ Cal
8 Advocates, by contrast, asserts that the SB 1440 Pilot Project does not meet the requirements of
9 17 CCR §95893(d)(3).²⁹ SBUA states that it did not identify definitive and specific
10 demonstrations of compliance in the Application with 17 CCR §§95893(d)(3), (d)(5) and
11 (d)(8).³⁰ Sierra Club does not directly assert that the SB 1440 Pilot Project fails to comply with
12 any provision of 17 CCR §95893 *et seq.* Rather, it argues that the Application has not sufficiently
13 demonstrated that the proposed SB 1440 Pilot Project will achieve greenhouse gas (GHG)
14 emission reductions.³¹

15 **A. The Proposed SB 1440 Pilot Project Complies with 17 CCR §95893(d)(3)**
16 **(Witness: James Lucas)**

17 Under 17 CCR §95893(d)(3), an allowance value, including any allocated allowance
18 auction proceeds, obtained by a natural gas supplier must be used for the primary benefit of the
19 supplier's retail natural gas ratepayers, consistent with the goals of Assembly Bill (AB) 32, and
20 not for the benefit of entities or persons other than such ratepayers.

21 Cal Advocates claims that the SB 1440 Pilot Project fails to meet this requirement
22 because SoCalGas does not demonstrate that SoCalGas, or any other entity, will procure, or has
23 committed to procure, the biomethane produced by the Project.³² Cal Advocates' reliance on the
24 existence of a biomethane procurement contract is misplaced. In D.24-01-060, the Commission
25 intentionally removed any utility procurement mandate for SB 1440 pilot projects,³³ allowing
26 these pilots to function primarily as technology demonstration and emissions evaluation projects

²⁸ BAC Testimony at 9.

²⁹ Cal Advocates Testimony at 2-2 and 2-3.

³⁰ SBUA Testimony at 5.

³¹ Sierra Club Testimony at 3.

³² Cal Advocates Testimony at 2-2 and 2-3.

³³ Available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M524/K234/524234908.PDF>.

1 rather than procurement-driven projects. This approach is consistent with the Commission’s
2 design of the SB 1383 Pilot Projects, which were likewise structured to generate ratepayer
3 benefits independent of a guaranteed utility procurement agreement.

4 By excluding a procurement requirement, the Commission made clear that ratepayer
5 benefits may include, among other things: technology evaluation, demonstration of technical
6 feasibility, emissions testing and monitoring, interconnection of Bio-SNG from woody biomass
7 into the utility pipeline system, and the reduction of uncertainty and risk for ratepayers.
8 Ratepayer benefits under AB 32 and the Cap-and-Invest framework do not hinge exclusively on
9 the existence of a biomethane procurement contract.

10 As explained in the Lucas/Summers Testimony, because the Commission approved
11 framework and evaluation process for the SB 1383 Projects proved effective, SoCalGas
12 appropriately applied a similar framework and assessment methodology in selecting the SB 1440
13 Pilot Project.³⁴ As discussed in Section II above, both the SB 1383 Pilot Projects and the
14 SB 1440 Pilot Project are first-of-their-kind pilots, implemented on a limited basis to evaluate
15 technical performance, costs, environmental benefits, long-term viability, and to generate data to
16 inform future program or policy decisions.

17 Given the Commission’s established framework recognizing how the SB 1383 Pilot
18 Projects can provide meaningful benefits to ratepayers, it is reasonable to conclude that the
19 SB 1440 Pilot Project will provide comparable benefits. In Decision (D.) 17-12-004, the
20 Commission adopted specific findings and requirements that enabled the SB 1383 Pilot Projects
21 to deliver direct benefits to retail natural gas customers, including the following:

- 22 • **Environmental benefits:** “[The Commission’s] goal is to select projects that are
23 financially sustainable in the long-term to ensure these investments provide the
24 expected environmental benefits to ratepayers and the State of California.”³⁵
 - 25 ○ The same rationale applies to the SB 1440 Pilot Project, with the primary
26 distinction that the biomethane source is woody biomass using gasification
27 rather than dairy manure using anaerobic digestion. The SB 1440 Pilot Project

³⁴ Lucas/Summers Testimony at JLMS-2.

³⁵ D.17-12-004 at 11.

1 is expected to deliver meaningful local air-quality benefits for ratepayers in
2 the San Joaquin Valley.³⁶

- 3 • **Ratepayer risk management:** Subjecting costs above the approved amounts to
4 reasonableness review appropriately balances innovation with ratepayer protection.³⁷
 - 5 ○ This principle applies equally here, with total SB 1440 Pilot Project costs
6 capped at \$19.704 million and funded entirely through Cap-and-Invest
7 proceeds, thereby protecting ratepayers from financial exposure.
- 8 • **Operational experience and cost data:** “The selected SB 1383 Pilot Projects are
9 required to participate in a dairy biomethane evaluation study and to report specified
10 data to the Selection Committee and the California Energy Commission.”³⁸
 - 11 ○ The SB 1440 Pilot Project will similarly generate operational and cost data
12 regarding conversion of woody biomass to Bio-SNG, methanation, carbon
13 management, and pipeline interconnection, benefiting present and future retail
14 gas customers by providing system-wide learning that can help lower
15 long-term gas procurement and interconnection costs

16 **B. The Proposed SB 1440 Pilot Project Complies with 17 CCR §95893(d)(5)**
17 **(Witnesses: James Lucas and Dr. Matthew Summers)**

18 Pursuant to 17 CCR §95893(d)(5), natural gas suppliers must demonstrate the expected
19 GHG emissions reductions, consistent with 17 CCR §95893(e)(4)(B), for each use of allocated
20 allowance auction proceeds undertaken pursuant to 17 CCR §§95893(d)(3)(A)-(B) that is
21 undertaken.

22 In D.20-12-031, the Commission found it appropriate to allocate an additional \$40
23 million in funding from Cap-and-Invest allowance proceeds to the biomethane monetary
24 incentive program (BMIP) to fund the biomethane projects.³⁹ In doing so, the Commission
25 recognized that “[t]his is an appropriate use of gas utility Cap-and-[Invest] allowance proceeds

³⁶ Lucas/Summers Testimony at JLMS-15-16, Tables 1 and 2.

³⁷ D.17-12-004 at 10.

³⁸ *Id.* Appendix A at 3.

³⁹ D.20-12-031 at 14-15.

1 since every unit of biomethane injected into gas utility pipelines displaces a unit of fossil fuel
2 that would otherwise disperse GHG emissions into the atmosphere.”⁴⁰

3 The Commission further explained in D.20-12-031, consistent with 17 CCR
4 §95893(d)(3)(B), that a biomethane capture project must satisfy the following criteria to qualify
5 for the use of gas Cap-and-Invest allowance funds: (a) reduce emissions of uncombusted natural
6 gas, (b) not be mandated by any federal, state, or local health and safety requirement, (c) not be
7 mandated by SB 1371 (Leno, 2014), and (d) not be mandated by the Greenhouse Gas Emission
8 Standards for Crude Oil and Natural Gas Facilities (17 CCR §§95665-95677).⁴¹ The
9 Commission found that California biomethane capture projects, by their nature, satisfy all four
10 requirements because they: (a) displace fossil natural gas on a unit-for-unit basis, the GHG
11 emissions that would otherwise have occurred, (b) they are not mandated by any federal, state, or
12 local requirements for the specified purpose of promoting health and safety, (c) they are not
13 mandated by SB 1371 (Leno, 2014), and (d) they are not mandated by the Greenhouse Gas
14 Emission Standards for Crude Oil and Natural Gas Facilities (17 CCR Sections 95665-95677).⁴²

15 Applying this Commission precedent under D.20-12-031, the proposed SB 1440 Pilot
16 Project is eligible for Cap-and-Invest allowance funding under the BMIP as it similarly
17 (a) displaces fossil natural gas, reducing unit-for-unit the GHG emissions that would otherwise
18 have occurred, (b) is not mandated by any federal, state, or local requirements for the specified
19 purpose of promoting health and safety, (c) is not mandated by SB 1371 (Leno, 2014), and (d) is
20 not mandated by the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas
21 Facilities (17 CCR §95665-95677). In addition, to demonstrate compliance with 17 CCR
22 §95893(d)(3)(B), the Lucas/Summers Testimony developed baseline and use-case emissions
23 estimates for both GHGs and criteria air pollutants, as presented in Tables 1 through 3.⁴³ As
24 shown by the carbon intensity (CI) scores in Table 3, the CI for both use-case scenarios [without
25 carbon capture and storage (CCS) and with CCS] are respectively ~49% and ~170% lower than

⁴⁰ D.20-12-031 at 15.

⁴¹ *Id.* at 13.

⁴² *Id.*

⁴³ Lucas/Summers Testimony at JLMS 15-17.

1 the CI of natural gas.⁴⁴ These scores demonstrate substantial GHG emissions reductions relative
2 to conventional natural gas.

3 **1. Cal Advocates’ Assertions that the Potential GHG Reductions from**
4 **the SB 1440 Pilot Project are Questionable are Unsupported and**
5 **Premised on a Misunderstanding of Applicable Standards**

6 Cal Advocates asserts that SoCalGas has not demonstrated that the estimated GHG
7 reductions associated with the SB 1440 Woody Biomass Pilot Project are certain.⁴⁵ This claim is
8 unfounded and reflects a misunderstanding of (1) the standards applicable to pilot scale projects
9 funded with Cap-and-Invest proceeds, and (2) the purpose and role of GHG estimation at the
10 application stage.

11 Cal Advocates applies an incorrect standard. Neither 17 CCR §95893, D.22-02-025, nor
12 D.24-12-032 requires the SB 1440 Pilot Project to demonstrate realized or empirically measured,
13 or verified GHG reductions at the time of application approval. To the contrary, 17 CCR
14 §95893(e)(4)(B) expressly authorizes the use of allocated allowance auction proceeds for “other
15 GHG emission reduction activities,” provided that the natural gas supplier identifies the relevant
16 GHG reduction pathways and estimates⁴⁶ and reports reductions consistent with 17 CCR
17 §95893(d)(5). The regulation thus explicitly contemplates reasonable estimation and reporting
18 prior to project implementation, not ex post verification of performance outcomes.

19 Cal Advocates’ critique also improperly conflates uncertainty inherent in pilot projects
20 with inaccuracy. Pilot projects, by definition, are undertaken precisely because certain
21 parameters, such as operational performance, technical integration, cost profiles, and emissions
22 impacts, require real-world demonstration and evaluation. The existence of this uncertainty does
23 not undermine compliance with the regulatory framework, rather, it is the very reason the
24 Commission authorizes pilots. The Commission recognized this principle when it authorized
25 SB 1440 pilot projects and expressly directed that Cap-and-Invest funds may be used to offset
26 pilot-scale pipeline infrastructure and related costs. D.22-02-025 reflects the Commission’s

⁴⁴ These percentages are derived from CI scores of 36.1 g CO_{2e}/MJ (without CCS) and -49.7 g CO_{2e}/MJ (with CCS), as presented in the Lucas/Summers Testimony, which was updated to have consistent treatment of biogenic carbon.

⁴⁵ Cal Advocates Testimony at 2-3.

⁴⁶ CCR 17 §95893(e)(4)(B) specifically states, “Estimating the GHG emission reductions from each use of allocated allowance auction proceeds allowed pursuant to sections 95893(d)(3)(A)-(B).”

1 judgment that pilot projects may proceed on the basis of reasonable, good-faith estimates and
2 reporting commitments, rather than definitive or guaranteed performance outcomes.⁴⁷ Imposing a
3 certainty requirement at this stage would be inconsistent with both the purpose of SB 1440 Pilot
4 Projects, and longstanding Commission precedent governing demonstration-scale projects
5 funded with Cap-and-Invest proceeds.

6 **2. Sierra Club Misapplies Inapplicable Technology Comparisons and**
7 **Ignores Proven Commercial Carbon Capture and Sequestration**
8 **Benchmarks in an Attempt to Cast Doubt on the Project**

9 Sierra Club’s testimony asserts four primary reasons why the GHG analysis supporting
10 the SB 1440 Pilot Project is allegedly invalid and insufficient to demonstrate GHG reductions.⁴⁸
11 As explained below, none of these assertions provides a reasonable or supportable basis for
12 denying approval of the SB 1440 Pilot Project.

13 **a. Sierra Club’s Claim that the Application Fails to Demonstrate**
14 **Consistency with Validated Carbon-Intensity Models Is**
15 **Technically Flawed.**

16 Sierra Club argues that the Application does not demonstrate that its assessment of GHG
17 reductions is consistent with validated lifecycle models of carbon intensity. This argument
18 misstates both the regulatory requirements and the purpose of the analysis submitted.
19 D.22-02-025 does not prescribe any particular lifecycle emissions model, such as CA-GREET,
20 for evaluating SB 1440 Pilot Projects. Similarly, 17 CCR §95893 requires only that allowance
21 auction proceeds be used for projects that demonstrably reduce GHG emissions. The regulation
22 is outcome-based, not method-prescriptive. It imposes no obligation to use CA-GREET, or any
23 other specific modeling platform, but rather focuses on demonstrable emissions reductions.

24 The SB 1440 Pilot Project’s lifecycle analysis follows established methodologies and
25 properly reflects the regional benefits of displaced waste practices. Although Sierra Club
26 criticizes that the analysis did not use the CA-GREET,⁴⁹ the GREET methodology may be
27 validly applied as long as the analysis relies on identical mathematical calculations and validated
28 emission factors (such as those from the 2024 R&D GREET model). The 2024 R&D GREET

⁴⁷ D.22-02-025 at 67-68 (Ordering Paragraph (OP) 43).

⁴⁸ Sierra Club Testimony, Grubert at 6.

⁴⁹ *Id.* Grubert at 6.

1 model provides the most current available data for preliminary assessments before a project-
2 specific pathway is certified by CARB. Using these validated factors is standard practice for
3 pilot-phase evaluations and policy related analysis. The spreadsheet provided to Sierra Club by
4 SoCalGas and West Biofuels reasonably excludes extraneous information from the spreadsheet
5 prepared by Argonne Laboratory (retained to conduct the lifecycle analysis), to improve
6 transparency and traceability of the calculations.

7 With biogenic and non-biogenic emissions fully accounted for in both the base case and
8 use cases in the lifecycle analysis,⁵⁰ the net CI remains the most important factor for compliance
9 with 17 CCR §95893(d)(5).

- 10 • **Measuring Real-World Impact:** Net CI evaluates the emissions delta between the SB
11 1440 Pilot Project and “business-as-usual” waste disposal baseline.
- 12 • **Accounting for Avoided Regional Emissions:** Failing to use net CI would ignore the
13 reality that the biomass (or feedstock) would otherwise be subject to high-emissions
14 practices, such as air curtain burning.
- 15 • **Consistency with CARB Policy:** Net CI appropriately captures both lifecycle emissions
16 and eligible avoided emissions, consistent with CARB’s approach to low-carbon fuels
17 and waste diversion strategies. As noted in NREL’s memorandum titled “GREET
18 Analysis for Bio-SNG Project at the CCAGA Facility,”⁵¹ “To qualify this fuel pathway
19 with CARB’s Low Carbon Fuel Standard (LCFS) or other federal tax incentives, the
20 analysis will need to be updated to utilize the incentive-program-specific GREET model
21 and requirements at the time of application.” Accordingly, the GREET analysis provided
22 in the Application was conducted strictly to assess GHG impacts for pilot and
23 demonstration purposes, not to propose or certify an LCFS fuel pathway.

24 **b. Sierra Club’s Claim that the Base-Case Assumptions are**
25 **Questionable or Inconsistently Applied, Even Under GREET,**
26 **Is Incorrect and Unsupported By the Record.**

27 Sierra Club’s assertion that the base-case assumptions used to estimate emissions
28 particularly with respect to whole orchard recycling, are questionable or inconsistently applied is
29 unsupported by the record and inconsistent with standard lifecycle analysis practices. The

⁵⁰ As provided in the Lucas/Summers Testimony.

⁵¹ Lucas/Summers Testimony, Attachment 1.

1 following points demonstrate the SB 1440 Pilot Project’s methodology is scientifically grounded
2 and consistent with California’s decarbonization goals.

3 Sierra Club argues the SB 1440 Pilot Project’s estimate of 1,700 g CO₂e/kg for whole
4 orchard recycling (WOR) emissions is an “inflated” overestimate⁵². However, this figure is
5 derived directly from Culumber et al. (2025), a peer-reviewed academic study that the witness
6 admits is a valid summary of findings.⁵³

- 7 • **Avoided Emissions Framework:** The SB 1440 Project uses the 1,700 gCO₂e/kg to
8 establish a counterfactual baseline (the “business-as-usual” fate of the biomass) to
9 calculate avoided emissions.
- 10 • **Documented Carbon Flux:** Culumber et al. find that ~93% of biogenic carbon for the
11 incorporated orchard waste decomposes and returns to the atmosphere over a 20-year
12 period. Treating this flux as a baseline emission is necessary to quantify the climate
13 benefit of diverting that waste into Bio-SNG production.

14 Sierra Club also argues that the WOR base case should be treated as a carbon sink due to
15 soil sequestration⁵⁴. This assertion is unsupported by credible scientific research and data.

- 16 • **Limited Tracking Period:** The Culumber et al. (2025) study cited by Sierra Club
17 extrapolates a 20-year carbon retention period based on a 4-year study.
- 18 • **Lack of Long-Term Evidence:** Atmospheric or climate impacts are typically measured
19 on a 100-year time horizon. There is no scientific support in the evidentiary record for
20 Sierra Club’s conclusion that the estimated 4.05 Mg C/ha of carbon from WOR would
21 remain sequestered over a 100-year time horizon.⁵⁵ To the contrary, the available data
22 provide no basis to assume long-term permanence of that carbon stock. It is therefore
23 reasonable, and consistent with observed decomposition dynamics, to conclude that if
24 approximately 93% of the biogenic carbon returns to the atmosphere within a 20-year
25 period, the entirety of that biogenic carbon would be released over a 100-year timeframe.
26 Accordingly, the following two claims asserted by Sierra Club are unfounded and should
27 be disregarded, as their calculations rely on the unsupported assumption that the

⁵² Sierra Club Testimony, Grubert at 7.

⁵³ *Id.* Grubert at 9.

⁵⁴ *Id.* Grubert at 7-10.

⁵⁵ *Id.* Grubert at 9-10.

1 remaining approximately 7% of biogenic carbon would somehow cease returning to the
2 atmosphere over the subsequent 80-year period.

- 3 ○ “[I]n my opinion, there is a math error in the analysis presented by SoCalGas.
4 Specifically, the estimate of 1690 g CO₂e/kg of biomass provided in SoCalGas’s
5 Response 4-1 to Sierra Club’s data request corresponds to the incorrect
6 assumption that all 61.1 million grams of carbon per hectare (Mg C/ha) returns to
7 the atmosphere.”⁵⁶
- 8 ○ “[S]o I note also that accounting for the 4.05 Mg C/ha that Culumber et al. 2025
9 estimate are still stored in soil after 20 years post-WOR application as a
10 sequestration would mean that WOR has a CI of -101 g CO₂/kg of applied
11 biomass, contributing to net carbon dioxide removal rather than emissions for this
12 practice.”⁵⁷
- 13 ○ In discovery, Sierra Club (Grubert) agrees the Culumber et al. (2025) study does
14 not estimate the amount of carbon that will remain in the soil after 100 years.⁵⁸
15 Given that climate impacts are typically evaluated on a 100-year horizon, there is
16 no scientific basis in the record to assume the 4.05 Mg C/ha remaining after 20
17 years represents permanent sequestration, particularly given its vulnerability to
18 future land use changes.
- 19 • **Risk of Re-emission from Land Use Change:** Carbon stored in orchard soil residues is
20 highly vulnerable to land use change, redevelopment, or modified agricultural practices,
21 any of which would likely re-release stored carbon, nullifying any perceived "sink"
22 benefit of the base case.

23 **c. Sierra Club’s Assertion that Methane Emissions from**
24 **Biosynthetic Natural Gas (Bio-SNG) Manufacturing were**
25 **Improperly Excluded Is Unfounded.**

26 Sierra Club contends that the SB 1440 Pilot Project fails to account for methane
27 emissions associated with Bio-SNG production. Sierra Club acknowledges that “operational data

⁵⁶ Sierra Club Testimony, Grubert at 9.

⁵⁷ *Id.* Grubert at 10.

⁵⁸ SCG-Sierra Club-DR-02, Question 7, at 8 (Attachment 2 hereto).

1 on methane emissions from plants like the one proposed by SoCalGas are rare,”⁵⁹ yet
2 nevertheless relies on a study⁶⁰ that is not representative of the SB 1440 Pilot Project. The cited
3 study estimates methane losses from biogas plants to range from 0.4 to 14.9 percent by mass
4 from European biogas facilities and assumes without basis that this range applies to the SB 1440
5 Pilot Project. Using this assumption, Sierra Club asserts that methane leakage would increase CI
6 values by 2 to 88 g CO₂e/MJ.⁶¹ This conclusion is unsupported and misleading because the cited
7 study does not evaluate facilities comparable to the SB 1440 Pilot Project. Furthermore, the
8 Sierra Club (Grubert) states in discovery they lack direct experience with Leak Detection and
9 Repair (LDAR) protocols and industry practices for chemical plant equipment.⁶² The witness
10 also confirms that none of the projects cited for methane production successfully implemented
11 the thermochemical conversion proposed here.⁶³ Consequently, the high leakage rates the
12 witness suggests, derived from biological anaerobic digestion facilities with fundamentally
13 different leakage mechanisms, are speculative and inapplicable to this industrial process.

14 Key deficiencies in Sierra Club’s reliance on the study include:

15 • **Geographic inapplicability:**

16 The study was conducted exclusively in Denmark and necessarily reflects European
17 regulatory regimes and operating practices, not California or U.S. industrial standards.

18 • **Feedstock differences:**

19 None of the 23 biogas plants evaluated in the study used woody biomass. Most relied on
20 agricultural feedstocks such as manure, maize silage, wastewater sludge, or organic
21 waste.⁶⁴

⁵⁹ Sierra Club Testimony, Grubert at 11.

⁶⁰ Scheutz, Charlotte, and Anders M. Fredenslund. 2019. “Total Methane Emission Rates and Losses from Biogas Plants.” *Waste Management* 97 (September), *available at*: <https://americanbiogascouncil.org/wp-content/uploads/2023/07/Sheutz-et-al-Waste-Management-2019-Fugitive-Methane-Emissions-AD-Facilities.pdf>.

⁶¹ Sierra Club Testimony, Grubert at 12.

⁶² SCG-Sierra Club-DR-02, Questions 1, 2, at 1-2 (Attachment 2 hereto).

⁶³ *Id.*, Question 4, at 4.

⁶⁴ Scheutz, Charlotte, and Anders M. Fredenslund. 2019. “Total Methane Emission Rates and Losses from Biogas Plants.” *Waste Management* 97 (September), Table 1 at 40, *available at*: <https://americanbiogascouncil.org/wp-content/uploads/2023/07/Sheutz-et-al-Waste-Management-2019-Fugitive-Methane-Emissions-AD-Facilities.pdf>.

1 • **Technology differences:**

2 All evaluated facilities relied on anaerobic digestion,⁶⁵ not gasification. Anaerobic
3 digestion systems involve materially different process configurations, emissions
4 pathways, and operating conditions compared to gasification and methanation
5 technologies proposed for the SB 1440 Pilot Project. Anaerobic digestion systems operate
6 at low pressures with flexible covers prone to leakage, whereas the SB 1440 Pilot Project
7 utilizes thermochemical methanation, a fully enclosed, high-temperature, and high-
8 pressure industrial process designed using ASME pressure vessel codes and equipment.
9 The SB 1440 Pilot Project is more accurately compared to refinery methanation units or
10 industrial hydrogenation reactors, where emissions are governed by mechanical integrity
11 and rigorous Leak Detection and Repair (LDAR) programs rather than biological
12 containment.

13 • **Facility vintage:**

14 Several facilities dated to the 1980s and 1990s⁶⁶, predating modern emissions-control and
15 LDAR practices. Construction dates were not provided for the wastewater treatment
16 plants. These older facilities are not representative of the design standards or emissions
17 control practices proposed for the SB 1440 Pilot Project.

18 • **Digestate storage practices:**

19 Seven biogas plants used open digestate storage,⁶⁷ which the study itself identifies as a
20 significant methane-emission source⁶⁸, a condition that is not applicable to the SB 1440
21 Pilot Project and materially inflates the methane loss range.

⁶⁵ Scheutz, Charlotte, and Anders M. Fredenslund. 2019. "Total Methane Emission Rates and Losses from Biogas Plants." *Waste Management* 97 (September) at 39, available at: <https://americanbiogascouncil.org/wp-content/uploads/2023/07/Sheutz-et-al-Waste-Management-2019-Fugitive-Methane-Emissions-AD-Facilities.pdf>.

⁶⁶ *Id.*

⁶⁷ *Id.* at Table 1 at 40, available at: <https://americanbiogascouncil.org/wp-content/uploads/2023/07/Sheutz-et-al-Waste-Management-2019-Fugitive-Methane-Emissions-AD-Facilities.pdf>.

⁶⁸ *Id.* at 39, available at: <https://americanbiogascouncil.org/wp-content/uploads/2023/07/Sheutz-et-al-Waste-Management-2019-Fugitive-Methane-Emissions-AD-Facilities.pdf>.

1 Using the U.S. EPA Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-
2 017), West Biofuels conducted a component-level analysis showing that controlled methane
3 leakage is estimated at 1.84 kg/day, equivalent to 0.0685 gCO₂e/MJ, representing a mere 0.06%
4 of the facility’s direct emissions. This quantitative data confirms fugitive methane is de minimis
5 and illustrates its exclusion in the lifecycle modeling(see Attachment 1).

6 **d. Sierra Club’s Claims Regarding CCS Feasibility are Incorrect.**

7 Sierra Club characterizes the SB 1440 Pilot Project’s carbon capture goals as
8 “speculative” and “unsupported.”⁶⁹ This claim is directly contradicted by commercial CCS data.
9 Industry data from established global technology suppliers demonstrates that the SB 1440 Pilot
10 Project’s 80% capture target is a conservative and reasonable design basis.

- 11 • **Proven Commercial Performance:** Leading CCS suppliers explicitly claim and
12 demonstrate capture rates far exceeding the SB 1440 Pilot Project’s 78–80% estimate.
13 For example, GE Vernova reports post-combustion CCS solutions capable of capturing
14 more than 95% CO₂.⁷⁰
- 15 • **Standard Industry Design:** Multiple commercial modular CCS plants, such as those
16 from SLB Capturi, are designed for a standard performance of ~90% capture⁷¹ and have
17 been commercially deployed. Other major providers, including Shell CANSOLV, Baker
18 Hughes, and Carbon Clean also market systems with ~90% capture efficiency that have
19 been commercially demonstrated in power and industrial applications.⁷²
- 20 • **Conservative Project Benchmarking:** The SB 1440 Pilot Project’s 78–80% capture
21 target is a conservative design floor for this technology class. Leading suppliers like GE
22 Vernova specify capture rates of more than 95% for post-combustion CCS, while
23 standard modular systems from SLB Capturi and Shell CANSOLV are routinely
24 designed for ~90% capture efficiency. Relying on a target below these industry

⁶⁹ Sierra Club Testimony, Grubert at 6, Sahu at 28.

⁷⁰ Available at: <https://www.governova.com/gas-power/future-of-energy/carbon-capture-storage>.

⁷¹ Available at: <https://capturi.slb.com/>.

⁷² Available at: <https://www.long-intl.com/blog/post-combustion-capture/>,
<https://www.bakerhughes.com/carbon-capture-use-and-storage-ccus/carbon-capture>, and
<https://www.carbonclean.com/insights/solvent-based-carbon-capture-refineries>.

1 benchmarks reinforces the credibility and achievability of the Project’s GHG reduction
2 estimates.

3 **C. The Proposed SB 1440 Pilot Project Complies with 17 CCR §95893(d)(8)**
4 **(Witness: James Lucas)**

5 Under 17 CCR §95893(d)(8), “For allocated allowances received on or after October 1,
6 2017, the proceeds received from the sale of allowances allocated to a natural gas supplier must
7 be spent by December 31 of the year ten years after the vintage year of the allowances[.]” As
8 explained in the Lucas/Summers Testimony,⁷³ pursuant to Ordering Paragraph (OP) 48 of D.22-
9 02-025, any unspent Cap-and-Invest allowance proceeds shall be returned to ratepayers in the
10 California Climate Credit by December 31, 2032 pursuant to 17 CCR §95893(d)(8). The
11 allowance proceeds allocated to the SB 1440 Pilot Project total \$19.704 million and were
12 allocated and formally set aside in 2022. Accordingly, the SB 1440 Pilot Project satisfies the
13 expenditure timing and disposition requirements of 17 CCR Section 95893(d)(8).

14 **D. The Proposed SB 1440 Pilot Project Complies with 17 CCR**
15 **§§95893(e)(4)(A)- (B) (Witness: James Lucas)**

16 Natural gas suppliers are required under 17 CCR §§95893(e)(4)(A)-(B) to annually
17 submit a report to the CARB Executive Officer describing the disposition of allocated auction
18 proceeds during the previous calendar year. As stated in the Lucas/Summers Testimony, and
19 pursuant to D.22-02-025, OP 43, the SB 1440 Pilot Project is subject to ongoing data reporting
20 and evaluation requirements. These reports and evaluations must be submitted to the
21 Commission, its sister agencies, or SoCalGas, upon request.⁷⁴ Accordingly, the SB 1440 Pilot
22 Project fully complies with the reporting obligations set forth in 17 CCR §§ 95893(e)(4)(A) and
23 (B).

24 **VI. SCOPE ISSUE 5: SOCALGAS IS NOT PROPOSING TO USE THE \$19.704**
25 **MILLION IN CAP-AND-INVEST ALLOWANCE PROCEEDS TO RATEBASE**
26 **PIPELINE INFRASTRUCTURE COSTS (WITNESS: JAMES LUCAS)**

27 BAC states in testimony that it does not believe SoCalGas is proposing to ratebase any
28 SB 1440 Pilot Project costs because Cap-and-Invest allowance proceeds will be used to fund the

⁷³ Lucas/Summers Testimony at JLMS-19.

⁷⁴ *Id.* at JLMS-20.

1 pipeline interconnection and associated infrastructure.⁷⁵ SBUA similarly states that developer-
2 owned infrastructure costs should not be added to ratebase, citing concerns regarding
3 affordability impacts on ratepayers, including those in disadvantaged communities, ESJ
4 communities, and small businesses.⁷⁶ Neither Cal Advocates nor Sierra Club discuss the
5 ratemaking treatment of the SB 1440 Pilot Project in their respective testimonies.

6 BAC and SBUA are correct that SoCalGas is not proposing to ratebase any of the
7 proposed utility-owned or developer-owned pipelines and associated infrastructure. Instead,
8 SoCalGas proposes to utilize \$19.074 million in Cap-and-Invest allowance proceeds to fund
9 eligible project costs. As described in the Lucas/Summers Testimony, and pursuant to OP 46 of
10 D.22-02-025, \$19.704 million of Cap-and-Invest allowance proceeds were set aside to fund the
11 SB 1440 Pilot Project.⁷⁷ SoCalGas proposes to use these funds to pay for the pipeline
12 interconnection infrastructure identified in Lanes 7 through 9, as well as associated infrastructure
13 in Lanes 3, 4, and 5.⁷⁸ Because the SB 1440 Pilot Project is funded with Cap-and-Invest
14 allowance proceeds, SoCalGas is not seeking to place any project costs in ratebase and will not
15 earn a rate of return on the project.

16 To the extent that funding is directed for developer-owned pipelines and/or associated
17 infrastructure, SoCalGas will have no obligation to fund the ongoing maintenance and operations
18 associated with those facilities. Pursuant to SoCalGas's interconnection agreement with West
19 Biofuels, the developer, *i.e.*, West Biofuels, is solely responsible for costs associated with its
20 developer-owned pipelines and infrastructure.

21 **VII. SCOPED ISSUE 6: SOCALGAS AND WEST BIOFUELS SUPPORT PUBLIC**
22 **REPORTING OF METHANE LEAKAGE AND EMISSIONS DATA FOR THE SB**
23 **1440 PILOT PROJECT (WITNESS: JAMES LUCAS)**

24 Both BAC and SBUA support making methane leakage and emissions information
25 publicly available, subject to appropriate confidentiality protections. BAC states
26 “[SoCalGas/West Biofuels] will provide any and all emissions data that is appropriate.
27 Commercially sensitive data, which is premature to identify at this point, may be submitted to

⁷⁵ BAC Testimony at 10.

⁷⁶ SBUA Testimony at 6-7.

⁷⁷ Lucas/Summers Testimony at JLMS-18.

⁷⁸ *Id.* at JMLS-18.

1 the Commission with a request for limits on disclosure pursuant to D.21-09-020's processes and
2 Commission General Order 66-D's additional requirements.”⁷⁹ SBUA states it “support[s] public
3 access to methane leakage and emissions information to the extent that releasing such
4 information does not harm ratepayers or hinder the ability or confidentiality of project
5 developers and SCG to develop the Biomethane project.”⁸⁰ Neither Cal Advocates nor the Sierra
6 Club address this issue.

7 SoCalGas and West Biofuels are committed to transparency and accountability and
8 therefore support making methane leakage and emissions information publicly available for the
9 benefit of ratepayers, while maintaining appropriate protocols for confidential or proprietary
10 information where necessary. Consistent with the pilot nature of the SB 1440 Project and
11 recognizing the interest of the Commission and other state agencies in data collection and
12 evaluation, SoCalGas and West Biofuels support public reporting of methane emissions
13 performance to inform regulators, stakeholders, and the public. Public availability of this
14 information will help advance policy development and contribute to broader understanding of the
15 effectiveness of woody biomass-to-biomethane projects in reducing GHG emissions.

16 **VIII. SCOPED ISSUE 7: THE COMMISSION’S DECISION APPROVING SENATE**
17 **BILL 1383 DAIRY BIOMETHANE PROJECTS IS APPLICABLE TO THE**
18 **PROPOSED SB 1440 PILOT PROJECT (WITNESS: JAMES LUCAS)**

19 SoCalGas believes that the Commission’s decision approving and implementing the
20 Senate Bill 1383 Dairy Biomethane Pilot Projects, *i.e.*, D.17-12-004, is highly applicable and
21 instructive for the SB 1440 Pilot Project. In approving the SB 1383 Pilot Projects, the
22 Commission established a clear framework for evaluating biomethane pilot projects, including
23 infrastructure eligibility, funding treatment, and the pilot nature of the projects themselves.⁸¹ The
24 SB 1440 Pilot Project aligns closely with these principles, as it similarly seeks to evaluate an
25 emerging biomethane pathway, generate data to inform future policy decisions, operate within
26 established regulatory safeguards, and advance the state’s GHG reduction goals.

⁷⁹ BAC Testimony at 11.

⁸⁰ SBUA Testimony at 7.

⁸¹ *See* D.17-12-004 at 2 (“This decision establishes the necessary framework to direct gas corporations to implement not less than five dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system and allow for rate recovery of reasonable infrastructure costs pursuant to Senate Bill 1383”).

1 BAC concurs that SoCalGas’s Application is consistent with the Commission’s SB 1383
2 decision, particularly with respect to the project readiness framework and emissions study and
3 reporting.⁸² SBUA similarly supports the Selection Committee’s criteria established under
4 SB 1383, highlighting the importance of “Economic Viability, [GHG] Reduction, **Cost**
5 **Effectiveness**, Community Impacts and Mitigation, and **Localized Economic Benefits.**”⁸³
6 Neither Cal Advocates nor the Sierra Club address the applicability of D.17-12-004 to the
7 SB 1440 Pilot Project.

8 **A. Project Readiness Framework**

9 Consistent with the SB 1383 Pilot Projects, SoCalGas proposes to apply the same Project
10 Owner - Demonstration of Project Readiness checklist to the SB 1440 Pilot Project.⁸⁴ Prior to
11 SoCalGas incurring significant costs associated with the procurement of materials and
12 construction of facilities in Lanes 7 through 9 (as depicted in Figure 2),⁸⁵ West Biofuels will be
13 required to demonstrate project readiness. Specifically, West Biofuels must submit
14 documentation demonstrating compliance with each requirement set forth in Schedule D of the
15 SB 1440 Gasification/Pyrolysis Pilot Project Funding Agreement.⁸⁶

16 **B. Emissions Study and Reporting**

17 Consistent with D.17-02-004, which requires SB 1383 pilot developers to report
18 emissions and operational data to the Selection Committee and the CEC for use in future
19 studies,⁸⁷ SoCalGas proposes to require the SB 1440 Pilot Project to participate in data reporting
20 and evaluations, including emissions study and reporting. As stated in the Lucas/Summers
21 Testimony, SB 1440 Pilot Project data will be submitted to the Commission, its sister agencies,
22 or SoCalGas upon request,⁸⁸ and the project must allow these agencies to monitor and evaluate
23 reported data. Commercially sensitive data may be submitted with a request for confidential

⁸² BAC Testimony at 11-12.

⁸³ SBUA Testimony at 8 (emphasis in original).

⁸⁴ Lucas/Summers Testimony at JLMS-19-20.

⁸⁵ *Id.* at JLMS-7.

⁸⁶ Application of SoCalGas Proposing Woody Biomass Pilot Project, Attachment B.

⁸⁷ D.17-02-004, Appendix B at 4.

⁸⁸ Lucas/Summers Testimony at JLMS-20.

1 treatment pursuant to D.21-09-020 and Commission General Order 66-D. SoCalGas will work
2 with the Commission and relevant agencies to develop an appropriate reporting template.⁸⁹

3 **C. Biomethane Monetary Incentive Program**

4 As of the submittal of this rebuttal testimony, 100 percent of the funding allocated to
5 SoCalGas under the Biomethane Monetary Incentive Program (BMIP) has been fully subscribed
6 by previously approved projects, and the program is currently authorized to sunset on
7 December 31, 2026.⁹⁰ If the Commission authorizes additional BMIP funding and extends the
8 program's sunset date, the SB 1440 Pilot Project should be deemed eligible to seek any available
9 BMIP incentives, consistent with the Commission's prior treatment of the SB 1383 Pilot
10 Projects.

11 **IX. SCOPED ISSUE 8: THE SB 1440 PILOT PROJECT ADVANCES KEY GOALS**
12 **OF THE COMMISSION'S ENVIRONMENTAL AND SOCIAL JUSTICE**
13 **ACTION PLAN**

14 SoCalGas submits that the SB 1440 Pilot Project directly advances Environmental and
15 Social Justice (ESJ) Action Plan goals 1, 2 and 7. BAC concurs that the Project supports ESJ
16 Goals 2 and 7,⁹¹ and SBUA similarly finds that the SB 1440 Pilot Project can have direct impacts
17 on Goals 1, 2 and 7.⁹² Sierra Club asserts that the SB 1440 Pilot Project conflicts with Goals 2
18 and 9;⁹³ however those assertions are not supported by the full record in this proceeding. Cal
19 Advocates does not address the SB 1440 Pilot Project's alignment with the Commission's ESJ
20 Action Plan.

21 **A. The Project Supports ESJ Goal 1 by Promoting Economic and**
22 **Environmental Benefits in Local ESJ Communities (Witness: James Lucas)**

23 ESJ Goal 1 directs the Commission to integrate equity and access considerations into
24 regulatory decision-making, including consideration of the needs of underserved communities.⁹⁴

⁸⁹ *Id.* at JLMS-20.

⁹⁰ SoCalGas Rule 45 at Sheet 21, *available at*:
<https://tariffsprd.socalgas.com/view/tariff/?utilId=SCG&bookId=GAS&tarfKey=600>.

⁹¹ BAC Testimony at 12.

⁹² SBUA Testimony at 11.

⁹³ Sierra Club Testimony, Sahu at 39-40.

⁹⁴ Environmental & Social Justice Action Plan Version 2.0 at 8 and 23.

1 The project is located in the San Joaquin Valley, a region that has been identified by the state as
2 both economically disadvantaged and among the most pollution-burdened in California.⁹⁵ The
3 SB 1440 Pilot Project converts agricultural waste, woody biomass generated by the almond
4 industry, which presents disposal challenges in the region, into biomethane for injection into the
5 existing natural gas pipeline system.⁹⁶ By siting this project where the feedstock is generated, the
6 investment promotes localized economic and measurable environmental benefits for the same
7 communities that currently bear the environmental burdens of agricultural waste disposal.

8 **B. The Project Supports ESJ Goal 2 by Increasing Clean Energy Investment**
9 **and Improving Local Air Quality (Witness: Dr. Matthew Summers)**

10 ESJ Goal 2 prioritizes increased investment in clean energy resources that benefit ESJ
11 communities, particularly through improved local air quality and public health outcomes. BAC
12 strongly supports this objective and concludes that the SB 1440 Pilot Project would provide
13 significant investment in clean energy and reductions in local air pollution in disadvantaged
14 communities in Kern County.⁹⁷ BAC cites findings from CalEPA, CAPCOA, and the U.S.
15 Department of Energy demonstrating that bioenergy facilities and gasification-based processes,
16 produce dramatically lower emissions than alternative methods of managing the same
17 agricultural waste.⁹⁸

18 Sierra Club’s testimony focuses narrowly on emissions produced by the West Biofuels
19 gasification facility in isolation, without accounting for the emissions displaced by replacing
20 current disposal practices. Indeed, when questioned, Sierra Club’s witness, Dr. Sahu was asked if
21 the Bio-SNG production use cases generate less emissions than the baseline practices and his
22 response was, “[I] do not believe that the figures presented in Table 1 for the ‘Use Case’
23 scenarios, both with and without CCS, are correct or supported by the available evidence.

⁹⁵ Office of Environmental Health Hazard Assessment (OEHHA), CalEnviroScreen 4.0 (October 2021), available at: <https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40>. Under SB 535, CalEPA designates the highest-scoring census tracts — concentrated heavily in the San Joaquin Valley — as disadvantaged communities for purposes of directing Cap-and-Invest investment.

⁹⁶ California Air Resources Board (CARB), Staff Report: Agricultural Burning Alternatives Analysis Report (October 8, 2021) at 1-2: available at: https://ww2.arb.ca.gov/sites/default/files/2021-10/Agricultural_Burning_Alternatives_Analysis_Report.pdf.

⁹⁷ BAC Testimony at 12.

⁹⁸ *Id.* at 4-5.

1 Therefore, a comparison of the base case and use cases, will not show the emissions effects of
2 the Project.”⁹⁹ This statement reflects an unsupported assertion rather than a substantive rebuttal.
3 Sierra Club did not develop and present its own quantified analysis, that base case emissions are
4 lower than those of the proposed use cases.

5 Furthermore, Sierra Club’s testimony correctly identifies that Kerman ranks in the 88th
6 percentile burden under CalEnviroScreen 4.0 and is designated as a disadvantaged community
7 under SB 535.¹⁰⁰ However, this fact supports approval, not rejection of the SB 1440 Pilot
8 Project. Approving the SB 1440 Pilot Project directly addresses these sources by converting
9 agricultural waste into pipeline biomethane through a controlled process with enforceable
10 emission standards, directly mitigating the pollution burden that CalEnviroScreen is measuring.
11 Denying the project does nothing to reduce those existing burdens; it simply preserves the status
12 quo.

13 **C. The Project Supports ESJ Goal 7 by Creating High-Quality Jobs and**
14 **Economic Opportunity (Witness: Dr. Matthew Summers)**

15 ESJ Goal 7 seeks to promote high career paths and economic opportunities for residents
16 of ESJ communities. BAC notes that studies by the Clean Air Task Force and the RAND
17 Corporation demonstrate that bioenergy projects generates more jobs and a higher proportion of
18 permanent, well-compensated jobs than other forms of clean energy.¹⁰¹ BAC further observes
19 that the California Jobs First plans developed for the San Joaquin Valley identify agricultural
20 waste-to-energy conversion as a priority for regional economic development and job creation.¹⁰²
21 CARB has similarly recognized that bioenergy infrastructure can generate billions of dollars in
22 investment and thousands of jobs statewide.¹⁰³ The SB 1440 Pilot Project is directly aligned with
23 these state and regional objectives.

⁹⁹ Sierra Club Testimony, Sahu at 34.

¹⁰⁰ *Id.* Sahu at 19-20.

¹⁰¹ BAC Testimony at 5 (referencing, Clean Air Task Force: An Exploration of Options and Opportunities for the San Joaquin Valley Clean Energy Future, issued in November 2024).

¹⁰² BAC Testimony at 5 California Jobs First plans for the: North San Joaquin Valley at 36 and 39, Central San Joaquin Valley at 28, and Kern County at 25 *available at*: <https://www.labor.ca.gov/regional-investment-initiative>.

¹⁰³ BAC Testimony at 5-6.

1 As described in the Lucas/Summers Testimony, West Biofuels plans to support the local
2 community through inclusive community engagement, workforce development, and
3 environmental oversight. The SB 1440 Pilot Project will create opportunities for small, local, and
4 diverse businesses and encourage participation from disadvantaged communities.¹⁰⁴ West
5 Biofuels anticipates approximately 20 direct full-time permanent positions, approximately 60
6 temporary construction jobs during the 18-month build phase, and an estimated 37 supplier jobs
7 and 66 induced jobs based on Economic Policy Institute employment multipliers, totaling over
8 120 ongoing jobs in that local economy.¹⁰⁵

9 In conclusion, the SB 1440 Pilot Project advances the Commission’s ESJ Action Plan by
10 directing clean energy investment into a disadvantaged region, reducing pollution from existing
11 agricultural waste practices, creating high quality jobs, and aligning with state and regional
12 economic development priorities for the San Joaquin Valley.

13 **X. STAKEHOLDER OUTREACH AND SIERRA CLUB’S CLAIMS REGARDING**
14 **EMISSIONS MONITORING, REPORTING, AND IMPACT ON**
15 **DISADVANTAGED COMMUNITIES**

16 **A. Community Outreach and Meaningful Stakeholder Engagement will Occur**
17 **Following Commission Approval (Witnesses: James Lucas and Dr. Matthew**
18 **Summers)**

19 SBUA contends that SoCalGas and West Biofuels have not yet engaged local small
20 businesses or community stakeholders and that outreach materials have not been developed. As
21 noted in the Lucas/Summers Testimony, SoCalGas has conducted high-level discussions with the
22 City of Visalia and the CA Department of Conservation,¹⁰⁶ and more recently, with the San
23 Joaquin Valley Air Pollution Control District. West Biofuels has also held preliminary
24 discussions with Central California Almond Growers Association (CCAGA) and its grower
25 members, the Western Tree Nut Association, and Almond Board of California about the project
26 and the potential of partnering on feedstock with nut farming businesses.

27 SoCalGas/West Biofuels remain committed to robust and meaningful stakeholder
28 engagement and will initiate broader outreach following Commission approval. Conducting
29 significant engagement activities prior to approval, especially where the project’s scope or

¹⁰⁴ Lucas/Summers Testimony at JLMS-17.

¹⁰⁵ SCG Response to SBUA DR1.

¹⁰⁶ Lucas/Summers Testimony at JLMS-9.

1 design may change based on the Commission’s determination, would be premature and could
2 create confusion. Notably, neither D.22-02-025 or D.24-12-032 requires pre-approval outreach,
3 and no such requirement was scoped in this proceeding.

4 **B. Sierra Club’s Claims Regarding Emissions Monitoring and Reporting are**
5 **Erroneous (Witness: James Lucas)**

6 Sierra Club incorrectly asserts that “SoCalGas has not shown that the emissions from the
7 proposed Project will be studied and reported as the Commission required in D.22-02-025.”¹⁰⁷

8 Sierra Club attempts to support this claim by stating, “It is my opinion that without important
9 additional details relating to project design emissions estimates, and how emissions are to be
10 monitored including monitor types, locations, and durations, it is impossible to determine
11 whether the proposed Project complies with D.22-02-025[.]”¹⁰⁸ However, this contention
12 misstates the Commission’s requirements.

13 Neither D.22-02-025 nor D.24-12-032 requires an applicant to submit a finalized
14 emissions monitoring design as a condition for approval. Rather, D.22-02-025 requires only that
15 the pilots “study and report fugitive methane, pollutant, and particulate matter emissions and
16 emissions reduction or elimination methods in the gasification or pyrolysis process, the
17 methanation process, and pipeline infrastructure,”¹⁰⁹ The Lucas/Summers Testimony provides a
18 clear framework for compliance, including collaboration “with the Commission and/or other
19 state agencies to develop a reporting template for the SB 1440 Pilot Project.”¹¹⁰ This approach is
20 consistent with the SB 1383 Dairy Biomethane Pilot Projects. The Commission and its
21 constituent agencies are leading the data reporting process in such projects.¹¹¹ The Application
22 thus contemplates monitoring, studying, and reporting emissions by proposing to utilize the
23 existing processes used by these pilot projects, pending determination by the Commission and its
24 constituent agencies.

¹⁰⁷ Sierra Club Testimony, Sahu at 19.

¹⁰⁸ *Id.* Sahu at 20.

¹⁰⁹ D.22-02-025 at 68 (Ordering Paragraph (OP) 43).

¹¹⁰ Lucas/Summers Testimony at JLMS-20.

¹¹¹ D.17.12-004, Attachment B at 4.

1 **C. Response to Sierra Club’s Inaccurate Claims Regarding Criteria Pollutant**
2 **Emissions and Impacts on ESJ Communities (Witness: Dr. Matthew**
3 **Summers)**

4 Sierra Club characterizes the SB 1440 Pilot Project as a threat to residents in the City of
5 Kerman. This narrative is flawed for several reasons. Sierra Club’s analysis fails to account for
6 existing baseline emissions affecting the local community under business-as-usual conditions
7 and ignores the substantial geographic separation between the proposed West Biofuels facility
8 and the populated areas of the City of Kerman.

9 **1. Sierra Club Omitted Avoided Baseline Emissions in its Assessment**

10 Sierra Club’s conclusion that the SB 1440 Pilot Project will "worsen air quality"¹¹² omits
11 emissions from existing waste disposal practices that the project would displace, including air
12 curtain burning, biomass power generation, and diesel-intensive handling operations. By
13 focusing solely on facility emissions and ignoring displaced baseline emissions, Sierra Club fails
14 to assess net regional impacts. By diverting biomass into a controlled, thermochemical industrial
15 process with gas cleaning and flaring protocols, the SB 1440 Pilot Project can provide a superior
16 environmental alternative to current practices.

17 **2. The SB 1440 Pilot Project has Negligible Local Impacts Due to**
18 **Facility Distance**

19 Sierra Club’s analysis fails to account for the significant geographical buffer between the
20 West Biofuels facility and the populated area of the City of Kerman.¹¹³ The West Biofuels
21 facility is located approximately 7-8 miles from the populated areas of Kerman. At this distance,
22 atmospheric dispersion significantly reduces pollutant concentrations. The San Joaquin Valley
23 Air Pollution Control District (SJVAPCD) will evaluate air toxics impacts at the property line
24 and nearest sensitive receptors as part of the permitting process. The air toxics evaluation is
25 conducted consistent with the California Air Resources Board (CARB) Air Toxics “Hot Spots”
26 Information and Assessment Act (AB 2588; Health & Safety Code §§44300–44394)¹¹⁴ and
27 SJVAPCD Rule 2201 (New and Modified Stationary Source Review)¹¹⁵, which together focus

¹¹² Sierra Club Testimony, Sahu at 38.

¹¹³ *Id.* Sahu at 35-38.

¹¹⁴ Available at: <https://ww2.arb.ca.gov/our-work/programs/ab-2588-air-toxics-hot-spots>.

¹¹⁵ Available at: <https://ww2.valleyair.org/media/zzslqswt/rule-2201.pdf>.

1 on identifying and managing localized health risks from stationary sources. Projects cannot
2 proceed if they are determined to have significant impacts without mitigation. Also, Sierra Club
3 (Sahu) admits in discovery their testimony “did not assume any distances” when providing
4 findings on local health impacts.¹¹⁶ Characterizing a facility as a direct threat to a population
5 center without accounting for the 7-to-8-mile geographical buffer is a fundamental
6 methodological flaw that invalidates their claims of local harm to Kerman residents.

7 Under the CARB Air Toxics Hot Spots program and SJVAPCD health risk assessment
8 practices, meaningful air toxics impacts are localized near emission sources. EPA-approved air
9 dispersion modeling demonstrates that concentrations of toxic air contaminants decrease rapidly
10 with distance due to dilution and atmospheric mixing.¹¹⁷ At a distance of approximately 7-8
11 miles, incremental concentrations from an individual stationary source are indistinguishable from
12 regional background levels and do not materially affect lifetime cancer risk or chronic hazard
13 indices. Accordingly, air toxics impacts at the population center from this project are less than
14 significant under CARB and SJVAPCD risk evaluation frameworks.

15 **3. Sierra Club Misrepresents the Regulatory and Permitting Process**

16 Sierra Club misrepresents the air permitting process by suggesting it allows for
17 unchecked pollution increases in a nonattainment area¹¹⁸ Sierra Club (Sahu) states in discovery
18 that it “cannot speak to what ‘review[]’ will be conducted, how thoroughly this Project will be
19 evaluated by the San Joaquin Valley Air Pollution Control District, or what if any offsets or
20 improvement will be required as a result of the proposed Project.”¹¹⁹ This admission underscores
21 that Sierra Club’s claims of unchecked pollution increases are speculative and fail to account for
22 the mandatory regulatory safeguards and net regional improvements inherent in the SJVAPCD
23 permitting process. In reality, all SJVAPCD-regulated projects must comply with the region’s
24 Attainment Plan, which typically requires offsets or regional improvements as a condition of
25 approval. For example, the 2024 PM2.5 Attainment Plan requires New Source Review and
26 Emissions Reduction Credits for new facilities to ensure that regional emissions of criteria

¹¹⁶ SCG-Sierra Club-DR-03, Question 1a, at 1 (Attachment 3).

¹¹⁷ Available at: <https://www.epa.gov/AirToxScreen/airtoxscreen-overview>.

¹¹⁸ Sierra Club Testimony, Sahu at 37-38.

¹¹⁹ SCG-Sierra Club-DR-03, Question 14c, at 21 (Attachment 3).

1 pollutants are maintained or reduced in order to permit new projects.¹²⁰ By replacing high-
2 emission agricultural burning with controlled and permitted operations, the SB 1440 Pilot Project
3 supports the Commission’s ESJ and clean air objectives.

4 **4. Sierra Club Misrepresents West Biofuels’ Track Record**

5 Sierra Club’s testimony mischaracterizes the project as an experimental research facility
6 prone to frequent flaring.¹²¹ West Biofuels has a documented track record of operational history
7 and technical maturity and developing technical data through CEC, DOE, and USFS-funded
8 projects.¹²² Contrary to assertions that the SB 1440 Pilot Project is an experimental project, West
9 Biofuels has successfully executed two interconnected distributed energy projects of the same
10 scale as the proposed SB 1440 Pilot Project.¹²³ These projects have achieved high-capacity
11 factors of greater than 90%, demonstrating that West Biofuel’s systems are engineered for high-
12 availability commercial service rather than sporadic research use.

13 Sierra Club’s assertion that the West Biofuels facility will require frequent stops and
14 starts, leading to “considerable” flaring, is incorrect. West Biofuels works with a team of
15 experienced industrial suppliers who provide specific process and emissions guarantees for their
16 equipment. The facility utilizes mature technology components, such as scrubbers and enclosed
17 thermal oxidizers, which are selected post-approval based on their ability to meet rigorous
18 destruction efficiency and performance standards.

19 Lastly, although the SB 1440 Pilot Project is designed to address specific data gaps
20 identified by the Commission regarding woody biomass gasification, it is not an experimental
21 laboratory installation. By employing refinery-grade equipment and relying on experienced
22 professional process engineers, the SB 1440 Pilot Project is engineered for reliable, continuous
23 operation. This design directly advances the Commission’s objective of evaluating the

¹²⁰ Available at: <https://ww2.valleyair.org/media/htymci5y/appendix-h.pdf>.

¹²¹ Sierra Club Testimony, Sahu at 25-26.

¹²² Available at: <https://www.westbiofuels.com/history>, <https://www.westbiofuels.com/pr-042223>,
<https://www.westbiofuels.com/pr-022924>, and <https://bioenergyca.org/2026/02/us-forest-service-highlights-west-biofuels-need-for-forest-bioenergy/>.

¹²³ West Biofuels constructed, commissioned and started commercial operations of the Hat Creek Bioenergy facility located in Burney, CA in 2025 and a rice hull bioenergy facility located in Williams, CA in 2022. Both are actively producing renewable energy from biomass for the California grid. available at: <https://www.westbiofuels.com/history>.

1 commercial viability of woody biomass gasification technologies to inform future energy policy,
2 rather than merely testing theoretical or experimental concepts.

3 In conclusion, Sierra Club’s testimony selectively focuses on facility proximity and
4 hypothetical risks while ignoring avoided baseline emissions, regulatory safeguards, and West
5 Biofuels’ operational capabilities. When evaluated on a complete record, the SB 1440 Pilot
6 Project is an important tool to reduce regional pollution, advance ESJ goals, and fulfill the
7 requirements of D.22-02-025 and D.24-12-032.

8 **XI. CONCLUSION**

9 For the reasons discussed in this rebuttal testimony, SoCalGas has demonstrated that the
10 SB 1440 Pilot Project is consistent with the Commission’s directives and precedent, complies
11 with applicable decisions and regulations, appropriately uses Cap-and-Invest allowance
12 proceeds, and advances the State’s emissions reductions and ESJ objectives. The record shows
13 broad support from intervenors such as BAC and SBUA, while the objections raised by Cal
14 Advocates and Sierra Club rest on misinterpretations of Commission decisions, inappropriate
15 standards for pilot projects, and incomplete analyses that fail to consider displaced baseline
16 emissions, regulatory safeguards, and the purpose of pilot-scale demonstration projects. When
17 evaluated as a whole, the SB 1440 Pilot Project represents a carefully structured pilot that will
18 (i) generate valuable operational, emissions, and cost data, (ii) reduce uncertainty for ratepayers,
19 (iii) advance clean energy innovation, and (iv) provide meaningful benefits to disadvantaged
20 communities. Accordingly, SoCalGas respectfully requests that the Commission approve the
21 SB 1440 Pilot Project as proposed.

22 This concludes our prepared rebuttal testimony.

ATTACHMENT 1

Calculation Memorandum

Methane Fugitive Emissions and Leak Rate Estimate – Bio-SNG Facility

To: Southern California Gas Company
From: Matthew D. Summers, PhD, P.E.
Date: March 19, 2026
Subject: Defensible facility methane leakage rate estimate using EPA Protocol component factors and LDAR controls
Project/Facility: CCAGA Facility/Fresno County

1. Purpose

This memorandum documents a conservative, calculation-based estimate of the facility-level methane leakage rate as a percent of methane throughput for a Bio-SNG production facility. The estimate is intended for use in permitting, GHG inventories, CEQA/air-district documentation, or related regulatory support materials.

2. Regulatory Basis and References

Equipment leak emissions are estimated using the U.S. Environmental Protection Agency (EPA) guidance document: Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). This EPA Protocol provides regulator-accepted methods for estimating fugitive emissions from valves, flanges, connectors, pumps, compressors, pressure relief valves (PRVs), and open-ended lines using component counts and average emission factors.

Leak detection practices and reduction effectiveness are evaluated using EPA LDAR guidance, including EPA Method 21, Optical Gas Imaging (OGI) protocols (40 CFR Part 60, Appendix K), and EPA regulatory impact analyses supporting NSPS 0000a and 0000b.

3. Facility Throughput Basis

Bio-SNG production rate: 750 MMBtu/day

Methane fraction of Bio-SNG product gas: 90% by volume

Methane energy throughput (denominator): $750 \times 0.90 = 675$ MMBtu/day CH₄

Higher heating value (HHV) of methane: 1,012 Btu/scf

Methane density at standard conditions: 0.0192 kg/scf

Equivalent methane throughput: 666,996 scf/day = 12,806 kg CH₄/day

4. Process Lanes and Gas Composition

Lane 2 – Biomass Gasification: Syngas service; assumed methane fraction = 11% by volume

Lane 3 – Bulk Gas Cleaning: Syngas service; assumed methane fraction = 11% by volume

Lane 4 – Gas Conditioning and Methanation: Bio-SNG service; assumed methane fraction = 90% by volume

5. Lane-Specific Equipment Inventories

Lane 2 – Biomass Gasification (Syngas, 11% CH₄)

| Component Type | Count |
|---------------------|-------|
| Valves | 12 |
| Flanges | 15 |
| Connectors | 5 |
| Open-ended lines | 1 |
| Pumps (gas service) | 0 |
| Compressors/PRVs | 0 |

Lane 3 – Bulk Gas Cleaning (Syngas, 11% CH₄)

| Component Type | Count |
|---------------------|-------|
| Valves | 28 |
| Flanges | 22 |
| Connectors | 6 |
| Open-ended lines | 4 |
| Pumps (gas service) | 2 |
| Compressors/PRVs | 2 |

Lane 4 – Gas Conditioning and Methanation (Bio-SNG, 90% CH₄)

| Component Type | Count |
|---------------------|-------|
| Valves | 44 |
| Flanges | 30 |
| Connectors | 10 |
| Open-ended lines | 4 |
| Pumps (gas service) | 2 |
| Compressors/PRVs | 10 |

6. EPA Protocol Emission Factors Applied

Average emission factors are taken from EPA Protocol Table 2-4 (oil and gas production operations; gas service):

Valves: 4.5×10^{-3} kg/hr/source

Flanges: 3.9×10^{-4} kg/hr/source

Connectors: 2.0×10^{-4} kg/hr/source

Open-ended lines: 2.0×10^{-3} kg/hr/source

Pumps (gas service): 2.4×10^{-3} kg/hr/source

Compressors and PRVs: conservatively assigned “Others – gas service” factor = 8.8×10^{-3} kg/hr/source

7. Methane Conversion and Calculation Assumptions

Total organic compound (TOC) emissions estimated using EPA emission factors are converted to methane by applying the lane-specific methane volume fraction (11% for syngas, 90% for Bio-SNG). No credit is taken for ethane or heavier hydrocarbons, which is conservative for methane leakage estimation.

8. Leak Detection and Repair (LDAR) Program and Reduction Credit

The facility is assumed to implement an enhanced LDAR program consisting of daily Optical Gas Imaging (OGI) surveys and monthly EPA Method 21 surveys using instruments capable of detecting concentrations below 500 ppm.

A conservative 75% methane reduction credit is applied relative to uncontrolled EPA Protocol emissions. This assumption is supported by EPA regulatory impact analyses for NSPS 0000a/0000 b, which show 60–80% mitigation for quarterly OGI programs, and peer-reviewed studies (e.g., Ravikumar and Lyon, 2018, Colorado State University METEC) demonstrating higher mitigation at increased survey frequency.

9. Methane Emissions Results by Lane

| Lane | Gas | CH ₄ frac | Uncontrolled (kg/day) | Controlled (kg/day) | MMBtu/day loss |
|---|---------|----------------------|-----------------------|---------------------|----------------|
| Lane 2 – Biomass Gasification | Syngas | 11% | 0.166 | 0.041 | 0.0087 |
| Lane 3 – Bulk Gas Cleaning | Syngas | 11% | 0.439 | 0.110 | 0.0231 |
| Lane 4 – Gas Conditioning and Methanation | Bio-SNG | 90% | 6.750 | 1.688 | 0.3558 |
| Total | | | 7.355 | 1.839 | 0.3877 |

10. Methane Leakage GWP (gCO₂e/MJ)

Bio-SNG Throughput = 750 MMBtu/day × 1055 MJ/MMBtu = 791,292 MJ/day

Uncontrolled leakage = (7.355 kg/day * 1000 g/kg ÷ 791,292 MJ/day) = 0.0093 g CH₄/MJ

Controlled leakage = $(1.839 \text{ kg/day} * 1000 \text{ g/kg} \div 791,292 \text{ MJ/day}) = 0.0023 \text{ g CH}_4/\text{MJ}$

If the 100-year global warming potential of 29.8 is assigned to methane, controlled leakage rate of the facility is estimated as 0.0685 gCO₂e/MJ.

11. Conclusions

- Using conservative equipment counts and EPA Protocol average emission factors, uncontrolled methane emissions are estimated at 7.36 kg/day.
- Applying a conservative 75% methane reduction credit relative to uncontrolled EPA Protocol emissions yields controlled methane emissions of 1.84 kg/day.
- The global warming potential of these emissions are estimated as 0.0685 gCO₂e/MJ which is 0.06% of the 116.55 gCO₂e/MJ that was estimated for the Bio-SNG plant direct emissions. This justifies ignoring these as a major source of emissions in the GREET analysis. They can be added to the tables but will make no numerical difference to the results taken to the fourth significant digit.

12. References

U.S. EPA (1995). Protocol for Equipment Leak Emission Estimates. EPA-453/R-95-017. November 1995.

U.S. EPA. Regulatory Impact Analysis for NSPS 0000a. EPA Office of Air and Radiation.

U.S. EPA. Appendix K to 40 CFR Part 60 — Optical Gas Imaging.

U.S. EPA / ERG. Technical Support Document: Optical Gas Imaging Protocol (2021).

Ravikumar, A.P. & Lyon, D.R. Impact of Survey Frequency on Emissions Mitigation at Oil and Gas Sites. EDF, 2018.

Colorado State University METEC. Optical Gas Imaging (OGI) Efficacy Project.

ATTACHMENT 2
Sierra Club Response to Data Request
SoCalGas-Sierra Club-02

California Public Utilities Commission Docket No. A.25-10-008

Application of Southern California Gas Company (U 904 G) Proposing Woody Biomass Pilot Project

Sierra Club Response to Data Request SoCalGas-Sierra Club-02

To: Ismael Bautista, Jr., on behalf of Southern California Gas Company (“SoCalGas”)

From: Nina Robertson, Earthjustice, on behalf of Sierra Club

Date Request Sent: March 19, 2026

Response Due: April 2, 2026

QUESTION 1:

Explain in detail Dr. Emily Grubert’s experience with the design or operation of chemical plants or petrochemical grade equipment.

RESPONSE 1:

Dr. Grubert has worked as a consultant on projects related to process safety for petroleum refineries and related facilities. She has not worked as a design or operations engineer on chemical plants or petrochemical-grade equipment.

QUESTION 2:

Explain in detail Dr. Emily Grubert's experience with Leak Detection and Repair (LDAR) protocols and industry practices for chemical plant equipment.

RESPONSE 2:

Dr. Grubert has experience with LDAR protocols and industry practices for natural gas pipelines. She does not have direct experience with LDAR protocols and industry practices for chemical plant equipment.

QUESTION 3:

Explain in detail Dr. Emily Grubert’s familiarity with U.S. Environmental Protection Agency (EPA) methodologies for calculating leakage and leakage risk from petrochemical plant equipment.

RESPONSE 3:

Dr. Grubert is familiar with U.S. EPA methodologies for calculating leakage and leakage risk from petrochemical plant equipment in an academic capacity and has published peer-reviewed research comparing U.S. EPA estimates to other estimates used in evaluating methane emissions. *See* Grubert, E., and A. R. Brandt. 2019. “Three considerations for modeling natural gas system methane emissions in life cycle assessment.” *Journal of Cleaner Production*, 222: 760–767. <https://doi.org/10.1016/j.jclepro.2019.03.096>, which is attached hereto as Attachment 1.

QUESTION 4:

Explain whether any of the projects referenced in page 2 of the Testimony of Dr. Emily Grubert when responding to the question, “Are you familiar with other projects that have intentionally produced methane from biogenic sources?” involved thermochemical conversion of biomass to Bio-SNG as is proposed in the PILOT PROJECT. If so, please provide previous analysis and all assumptions as to methane leakage and supporting documents.

RESPONSE 4:

Of the several cases for which Dr. Grubert has testified in other states that have involved the intentional production of methane from biogenic sources, none have successfully implemented thermochemical conversion of biomass to Bio-SNG, and none have had 0% lifecycle methane emissions validated.

QUESTION 5:

In reference to the question “Let’s first discuss the first basis for your concern. Please elaborate on why it is your expert opinion that SoCalGas’s CI scores are misrepresented as validated estimates” on page 6 of the Testimony of Dr. Emily Grubert,

QUESTION 5a:

Is it possible for the GREET methodology to be applied without using the actual spreadsheet provided by Argonne National Laboratory as long as the same mathematical calculations are made?

RESPONSE 5a:

Sierra Club objects on the grounds this question is vague and ambiguous as to the term “applied.”

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

No, for two reasons. First, replicating calculations externally to mimic a methodology would not appropriately be described as “using the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (“GREET”) model[,]” as claimed in the corrected testimony of James Lucas and Matthew Summers at JLMS-13, and as asserted in the November 20, 2025 memo of Eric C. D. Tan to Matthew D. Summers, included as Attachment 1 to the corrected testimony, which claims “[t]he Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model was used for the analysis” and cites “Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel) Available: <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.”

Second, while the GREET model has been validated extensively, replicative calculations have not been. This lack of validation reduces confidence in the outputs when the model itself is not being used. Thus, application of “the GREET methodology . . . without using the actual spreadsheet provided by Argonne National Laboratory” does not ensure accurate results.

QUESTION 5b:

Are there specific mathematical differences found between the calculations shown on the spreadsheet provided by SoCalGas and the calculations on the Argonne National Laboratory provided GREET spreadsheets?

RESPONSE 5b:

Sierra Club objects on the grounds this question is ambiguous and assumes facts not in evidence. It is unclear what SoCalGas means by the “Argonne National Laboratory provided GREET spreadsheets.” The “Argonne National Laboratory provided GREET spreadsheets,” were not made available in response to Sierra Club’s request seeking the GREET documents used to generate the proposed project’s carbon intensities. The corrected testimony of James Lucas and Matthew Summers references GREET on JLMS-13 and also “CA-GREET,” which is provided by the California Air Resources Board and not Argonne National Labs. The spreadsheet provided by SoCalGas to Sierra Club references “R&D GREET 2024” as the source for some, but not all, data.

Subject to and without waiving the foregoing objection, Sierra Club responds as follows:

The evidence available shows that significant mathematical differences are likely, although SoCalGas has not provided enough information to clearly demonstrate specific mathematical differences.

A main source for the calculations shown on the spreadsheet provided by SoCalGas, and a main driver of the conclusion that the calculations are not GREET outputs, is Culumber et al. 2025, which was published 1 September 2025 and first appeared online on 8 April 2025. *See* <https://www.sciencedirect.com/science/article/pii/S0167880925001963?via%3Dihub> (“Received 18 October 2024, Revised 23 March 2025, Accepted 25 March 2025, Available online 8 April 2025, Version of Record 8 April 2025.”) R&D GREET 2024 was released in 2024, and CA-GREET 4.0 has been active since 1 July 2025. *See* https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/cagreet4_documentation_07012025_2.pdf (dated July 1, 2025). There is no evidence that Culumber et al. 2025 was incorporated into CA-GREET 4.0 within those approximate two months from CA-GREET model documentation. Even if it had been, the way that data from Culumber et al. 2025 is included in the spreadsheet provided by SoCalGas is inconsistent with the treatment of biogenic CO₂ elsewhere in the GREET model family. For instance, the “Summary of Expansions and Updates in R&D GREET® 2025,” which is the current R&D model documentation, explicitly states on page 9:

The fates of biogenic carbon in forest residue are tracked across multiple pools and fluxes: sequestration in humus/microbial biomass, sequestration in inert organic matter, remaining in residues, and biogenic CO₂ emissions to atmosphere. A net biogenic carbon balance is reported. Two carbon-accounting approaches biogenic CO₂ emissions are implemented: (1) a carbon-neutral approach and (2) an explicit accounting approach coupled with a time-dependent discounted Global Warming Potential (GWP). <https://greet.anl.gov/publication-greet-2025-summary>.

Numerous other inputs to the SoCalGas-provided non-GREET spreadsheet reference sources other than GREET, as well. This further increases the likelihood that there are mathematical differences.

QUESTION 6:

In reference to the question “Let’s first discuss the first basis for your concern. Please elaborate on why it is your expert opinion that SoCalGas’s CI scores are misrepresented as validated estimates” on page 6 of the Testimony of Dr. Emily Grubert, Dr Grubert states, “Although CA-GREET is primarily used for the implementation of the California’s Low Carbon Fuel Standard, I would generally expect a GREET-based analysis for California compliance to be consistent with, or at least very clear on its lack of consistency with, the state-approved CI calculation model for fuels like biomethane,”

QUESTION 6a:

Would the result of a global warming potential analysis using CA-GREET vs. R&D GREET emissions factors be expected to lead to vastly different results or conclusions or is the methodology generally the same for these two models?

RESPONSE 6a:

Sierra Club objects on the grounds this question is vague and ambiguous and calls for speculation as to the terms “vastly different” and “generally the same.”

Subject to and without waiving the foregoing objection, Sierra Club responds as follows:

Yes, there are potentially substantial differences in results between the two models, especially given that conclusions are based on ranking carbon intensities by pathway. The weighting of particular types of emissions (essentially, what a GWP does) could change the rank. Whether this occurs in this case depends on the share of methane emissions for the overall greenhouse gas footprint, which SoCalGas did not estimate.

QUESTION 7:

In reference to page 9 of the Testimony of Dr. Emily Grubert where she states, “Culumber et al. find that 4.05 Mg C/ha of the originally applied 61.6 Mg C/ha remain in the soil after years,”

QUESTION 7a:

What amount of years does the study say the 4.05 Mg C/ha is estimated to stay in the soil?

RESPONSE 7a:

The study projects 4.05 MgC/ha remain in the soil after 20 years.

QUESTION 7b:

Does the study estimate the amount of carbon that will remain in the soil after 100 years?

RESPONSE 7b:

No, the study does not provide this estimate.

QUESTION 8:

Provide all citations and calculations supporting the following statement in the Testimony of Dr. Emily Grubert on page 10: "...I note also that accounting for the 4.05 Mg C/ha that Culumber et al. 2025 estimate are still stored in soil after 20 years post-WOR application as a sequestration would mean that WOR has a CI of -101 g CO₂/kg of applied biomass, contributing to net carbon dioxide removal rather than emissions for this practice."

RESPONSE 8:

See Response 2 to SoCalGas's first data request.

QUESTION 9:

In response to the question “Please summarize your concerns with SoCalGas’s methodology for calculating the CI score of the Project” on page 11 of the Testimony of Dr. Emily Grubert, Dr. Emily Grubert states, “CI (e.g., through CA-GREET or a modified version of that model that has been vetted and approved by the CPUC).”

QUESTION 9a:

If CPUC has not vetted and approved a modified version of the GREET model, what reasons make R&D-GREET emissions factors invalid for the preliminary analysis of the Global Warming Potential impacts of this proposed facility?

RESPONSE 9a:

Sierra Club objects on the grounds that this question mischaracterizes the testimony of Dr. Grubert.

Subject to and without waiving the foregoing objection, Sierra Club responds as follows:

The testimony of Dr. Grubert does not assert that the California Public Utilities Commission (“CPUC”) has not vetted and approved a modified version of the GREET model. The testimony of Dr. Grubert also does not state that using R&D-GREET emissions factors is invalid. The testimony of Dr. Grubert does assert that SoCalGas did not provide evidence that it used a validated GREET model at all, as is clear from the remainder of the sentence excerpted above, which reads in full:

In my opinion, SoCalGas has not provided a CI score estimate that is consistent with California’s validated approaches for calculating CI (e.g., through CA-GREET or a modified version of that model that has been vetted and approved by the CPUC), and as explained above, it appears to have misrepresented that its CI calculations—which have grave inconsistencies embedded—were done through a widely used, validated model (e.g. GREET).

QUESTION 10:

In reference to the study cited in footnote 21 of the Testimony of Dr. Emily Grubert on page 11,¹

- a. In this study, were any of the facilities studied using thermochemical conversion of biomass to Bio-SNG in a closed-loop system using refinery grade equipment?
- b. In this study, were any of the facilities staffed 24/7 with technicians tasked with preventing leaks?
- c. In this study, did any of the facilities use continuous leak detection or LDAR protocols?

RESPONSE 10:

Sierra Club objects to this request on the grounds that it calls for speculation.

Subject to and without waiving the foregoing objection, Sierra Club responds as follows:

- a. Dr. Grubert did not perform the study and does not have complete knowledge of what facility practices were in place, including whether any used thermochemical conversion of biomass to Bio-SNG in a closed-loop system using refinery grade equipment. Dr. Grubert's testimony cites the study as evidence that methane emissions can be high at biogas facilities such that an assumption of 0 emissions is likely inaccurate.
- b. Dr. Grubert did not perform the study and does not have complete knowledge of what facility practices were in place, including whether any of the facilities were staffed 24/7 with technicians tasked with preventing leaks. Relevant to the question, the study (attached hereto as Attachment 2) states on page 45 that "[w]ithin the last few years, this organisation has initiated a voluntary measurement programme with the aim of keeping CH₄ loss at a minimum via a target of 1% loss for the sector."
- c. Dr. Grubert did not perform the study and does not have complete knowledge of what facility practices were in place, including whether they use continuous leak detection or LDAR protocols. Relevant to the question, the study states on page 45 that "[w]ithin the last few years, this organisation has initiated a voluntary measurement programme with the aim of keeping CH₄ loss at a minimum via a target of 1% loss for the sector." The study also states on page 38, "[t]he on-site approach measures emissions from various single sources at the plant, and it is the method most commonly used[.]" and explains on page 39:

Recent measurement comparison studies have found that methods measuring the plant's total CH₄ emission often result in a higher emission rate in comparison to on-site measurements, where the total emission is obtained by summing up those measured from

¹ *Citing Scheutz, Charlotte, and Anders M. Fredenslund. 2019. "Total Methane Emission Rates and Losses from 23 Biogas Plants." Waste Management 97 (September): 38–46.*

single sources. The reason for the discrepancy between on-site and ground-based remote sensing approaches is most likely that single sources are overlooked and/or not identified, or they are technically not quantifiable when using a particular measurement technique (e.g. open tanks).

QUESTION 11:

In reference to footnote 22 of the Testimony of Dr. Emily Grubert on page 11,²

- a. In this study or any studies referenced, were any of the facilities studied using thermochemical conversion of biomass to Bio-SNG in a closed-loop system using refinery grade equipment?
- b. In this study or any studies referenced, were any of the facilities staffed 24/7 with technicians tasked with preventing leaks?
- c. In this study or any studies referenced, did any of the facilities use continuous leak detection or LDAR protocols?

RESPONSE 11:

Sierra Club objects to this request on the grounds that it calls for speculation.

Subject to and without waiving the foregoing objection, Sierra Club responds as follows:

- a. Dr. Grubert does not have complete knowledge of whether any of the facilities studied across every reference in the cited study used thermochemical conversion of biomass to Bio-SNG in a closed-loop system using refinery-grade equipment. Dr. Grubert's testimony cites the study as evidence that methane emissions can be high at biogas facilities such that an assumption of 0 emissions is likely inaccurate.
- b. Dr. Grubert does not have complete knowledge of whether any of the facilities studied across every reference in the cited study were staffed 24/7 with technicians tasked with preventing leaks. Relevant to the question, and as explained in Response 10(b) above, one cited study (i.e., Scheutz, Charlotte, and Anders M. Fredenslund. 2019. "Total Methane Emission Rates and Losses from 23 Biogas Plants." *Waste Management* 97 (September): 38–46) states on page 45 that "[w]ithin the last few years, this organisation has initiated a voluntary measurement programme with the aim of keeping CH₄ loss at a minimum via a target of 1% loss for the sector."
- c. Dr. Grubert does not have complete knowledge of whether any of the facilities studied across every reference in the cited study use continuous leak detection or LDAR protocols. Relevant to the question, and as explained in Response 10(c) above, one cited study (i.e., Scheutz, Charlotte, and Anders M. Fredenslund. 2019. "Total Methane Emission Rates and Losses from 23 Biogas Plants." *Waste Management* 97 (September): 38–46) states on page 45 that "[w]ithin the last few years, this organisation has initiated a voluntary measurement programme with the aim of keeping CH₄ loss at a minimum via

² Citing Grubert, Emily. 2020. "At Scale, Renewable Natural Gas Systems Could Be Climate Intensive: The Influence of Methane Feedstock and Leakage Rates." *Environmental Research Letters* 15 (8): 084041.

a target of 1% loss for the sector.” The same study also states on page 38, “[t]he on-site approach measures emissions from various single sources at the plant, and it is the method most commonly used[,]” and explains on page 39:

Recent measurement comparison studies have found that methods measuring the plant’s total CH₄ emission often result in a higher emission rate in comparison to on-site measurements, where the total emission is obtained by summing up those measured from single sources. The reason for the discrepancy between on-site and ground-based remote sensing approaches is most likely that single sources are overlooked and/or not identified, or they are technically not quantifiable when using a particular measurement technique (e.g. open tanks).

QUESTION 12:

Provide all DOCUMENTS, including calculations, relied upon to support the response of Dr. Emily Grubert on page 12 of her testimony to the question, “Please describe how you think methane emissions of this Proposed Project should be evaluated.”

RESPONSE 12:

The document is the open-access model provided in footnote 22 of Dr. Grubert’s testimony. It is attached hereto as Attachment 3.

Attachment 1



Three considerations for modeling natural gas system methane emissions in life cycle assessment

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ABSTRACT

Natural gas is a fossil fuel accounting for about 30% of US primary energy consumption. Climate change is one of the primary environmental issues associated with natural gas use: natural gas combustion releases carbon dioxide. A less emphasized issue is that natural gas is mostly methane, a potent greenhouse gas (GHG). The climate impact of natural gas use is thus sensitive to the amount of methane that escapes from the natural gas system unburned. We call attention to three considerations for modeling natural gas-related methane emissions in life cycle assessment (LCA). First, natural gas system methane leakage is inconsistently characterized and likely systematically underestimated by commonly used life cycle inventory (LCI) databases. Second, studies are often imprecise in assumptions about process boundaries. This matters because not all natural gas uses rely on the same infrastructure and induce the same methane leakage. Third, there is not yet a stable estimate for the global warming potential (GWP) of methane. Newer estimates tend to be larger, which further exacerbates the underestimation of GHG impacts from natural gas systems. Data uncertainty is common in LCA, but natural gas-related methane emissions deserve special attention due to their influence on a decision-relevant parameter (GHG intensity) in product systems across the economy.

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1. Introduction

Natural gas accounts for about 30% of US primary energy consumption (EIA, 2018) and is widely used for electricity generation, heating, and industrial purposes. Given its prevalence, natural gas is part of the life cycle of a large number of product systems. Natural gas is primarily comprised of methane (CH₄), the second most significant GHG for anthropogenic climate change, after carbon dioxide (CO₂) (Weyant et al., 2006). Methane has a relatively high global warming potential (GWP): even a small amount of emitted methane can result in substantial carbon dioxide-equivalent (CO₂e) GHG emissions, one of the most commonly studied environmental indicators (Grubert, 2017). Questions about the amount of methane that escapes to the atmosphere unburned from natural gas systems, which we will call methane leakage, are thus highly relevant to environmental impact evaluations like life cycle assessment (LCA).

Despite recent studies on methane leakage from natural gas systems, most of which suggest that leakage is underestimated

(Alvarez et al., 2018; Balcombe et al., 2018; Brandt et al., 2014; Farquharson et al., 2017; Heath et al., 2014; Littlefield et al., 2016; Sanchez and Mays, 2015; Zhang et al., 2014), little attention has been paid to the impact of methane leakage inventories on product carbon footprints. Natural gas is an indirect input to many products via electricity, heating, and chemical feedstock supply. As these inputs are typically background processes for product-specific LCAs, database defaults are often used. This ubiquity means that inaccurate methane leakage inventories are widely relevant to LCA and, especially given the small number of processes involved, should be priorities for LCA database improvement.

1.1. Methane leakage from natural gas systems

We will use the terms methane “leakage” or methane “emissions” interchangeably to refer to all methane emitted unburned from natural gas systems. Not all leakage is unintentional: for example, some safety systems are designed to release gas when a system becomes overpressured due to unusual operating conditions or equipment problems. Leakage is generally a combination of non-purposeful emissions (sometimes called fugitives) and

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designed or purposeful emissions (sometimes called vents).

Researchers have been concerned for decades about methane leakage from natural gas systems and its influence on climate change (Lelieveld et al., 2005, 1993; Meier et al., 2005), with substantial disagreement about the value and dynamics of leakage rates (Kirchgessner et al., 1997). Data from outside North America are sparse (though see Yacovitch et al., 2018, a recent study from the Netherlands), neglecting possibly significant regional variability (Bouman et al., 2015; Gibon et al., 2017). For example, a study comparing GHG emissions from coal versus shale gas-fired power generation in China versus United States (US) emissions factors due to a lack of Chinese data (Chang et al., 2015). Recent literature has suggested that methane emissions might be systematically underestimated by official inventories, in part because a substantial portion of emissions is due to large, infrequent, and unintentional releases that can be difficult to detect (Brandt et al., 2016, 2014). The exact volume of leakage is not precisely understood (Alvarez et al., 2012; Brandt et al., 2014; Burnham et al., 2012; Hausfather, 2015, 2014; Heath et al., 2014; Jeong et al., 2014; Lelieveld et al., 2005, 1993) due to regional variability (Allen et al., 2013; Jiang et al., 2011; Karion et al., 2015, 2013; Pétron et al., 2014), operational practices, regulatory context, and other factors.

The energy analysis community has primarily focused on leakage while examining whether substituting natural gas for coal in the electricity sector will reduce overall climate change impacts (Farquharson et al., 2017; Gilbert and Sovacool, 2017; Hausfather, 2015; Howarth et al., 2011; Roy et al., 2015). Less attention has been paid to the relative GHG impacts of natural gas-versus electricity-based residential and commercial applications like heating and cooking. Although leakage from the natural gas distribution system has been studied (Costello, 2014; Hendrick et al., 2016; Jackson et al., 2014; McKain et al., 2015; Phillips et al., 2013), end use leakage from equipment, homes and businesses is rarely assessed (for an exception see Lavoie et al., 2017). This lack of study is particularly apparent for residential applications where methane leakage from appliances might be environmentally relevant in a comparison across heating options (Oliphant, 1994).

1.2. Three claims about methane leakage in LCA databases

In this paper we make three claims with respect to the treatment of methane in LCA databases.

First, commonly used inventory databases are inconsistent and likely systematically underestimate methane leakage from the natural gas system. Major ambiguities within and across inventory databases are common. We examine how existing databases model methane leakage from the natural gas system and quantify the relevance of natural gas system leakage rates to the GHG footprint of basic materials to demonstrate the scope of this problem. Our results show that methane leakage from natural gas systems should be a priority target for inventory improvements.

Second, databases (and individual studies) have unclear or incorrect assumptions about which natural gas system processes are applicable for a given supply chain. This is important, as it affects both how users might respond to leakage and what methane emissions are assigned to a given use of natural gas.

Third, there is not yet a stable estimate for the GWP of methane, affecting comparability of LCA studies over time. Newer estimates of methane's GWP tend to be larger. Analysts studying comparative energy systems should perform sensitivity analysis on the GWP and should report actual methane masses rather than CO_{2e} only, to allow forward compatibility and comparability of results.

The analysis below examines and supports these claims in order. We will focus on US methane leakage in LCA databases, though many of the same issues apply to carbon footprinting or

environmental impact assessment studies.

2. Methods

2.1. Methane leakage in life cycle inventory databases

Given the vast amount of data needed for LCA and a desire for consistency across studies, LCA practitioners often use one of a few common life cycle inventory (LCI) databases. For major databases, we ask: 1) What do the databases assume about US natural gas system leakage rates? And 2), how significant is embodied natural gas-related methane leakage for GHG footprints of non-natural gas product systems?

2.1.1. Database assumptions

We examine leakage assumptions in several common LCI databases. Our primary goal is to illustrate current status and discrepancies rather than to provide a set of recommended values. We do, however, incorporate synthetic insights from the many recent studies that have estimated leakage outside the context of life cycle inventories (Abrahams et al., 2015; Allen et al., 2014, 2013; Alvarez et al., 2018; Balcombe et al., 2018; Brandt et al., 2014; Ge et al., 2016; Heath et al., 2014; Hendrick et al., 2016; Jeong et al., 2014; Jiang et al., 2011; Karion et al., 2015, 2013; Lavoie et al., 2017; Littlefield et al., 2016; Mitchell et al., 2015; Pétron et al., 2014; Phillips et al., 2013; Zimmerle et al., 2015).

We examine three databases, each of which is the most current version available:

- 1) Economic Input-Output Life Cycle Assessment (EIO-LCA) Model (Carnegie Mellon University Green Design Institute, 2008), 2002 Producer Price model;
- 2) The National Renewable Energy Laboratory (NREL) United States Life Cycle Inventory database (USLCI) (NREL, 2012); and
- 3) The ecoinvent database, version 3.5 (ecoinvent, 2018).

USLCI and EIO-LCA data are older and less frequently updated than ecoinvent data, but relevantly, these databases are free while ecoinvent is not. Thus, it is reasonable to expect that they remain in use. Some other common LCA tools base their US natural gas-related methane emissions on databases we assess, so these are implicitly assessed as well. For example, GREET uses EPA inventories and GaBi/Thinkstep uses the USLCI as source data.

In each case, we: 1) identify unit process data for US-based natural gas systems; 2) match available inventory processes with processes in the US natural gas system to evaluate coverage; 3) convert data from each database's inventory format to a mass of methane basis, using process-specific data on energy densities, pressure, and standard gas conditions; and 4) calculate methane emissions as a mass percentage of gross methane withdrawals for each included process.

To investigate the accuracy of LCI data, we compare them with three non-LCI leakage estimates: 1) a recent inventory for 2015 natural gas supply chain methane emissions based on facility-scale ground measurements and aircraft observations (Alvarez et al., 2018); 2) Environmental Protection Agency (EPA) greenhouse gas inventory (GHGI) estimates for 2013 (EPA, 2015); and 3) EPA GHGI estimates for 2015 (EPA, 2017). EPA GHGI mass emissions are converted to leakage rates using the method of Brandt et al. (2014). Year 2015 EPA GHGI results are the basis for many leakage parameters in Argonne National Laboratory's GREET model (Burnham, 2017), and these data reflect a recent change in calculation methodology for natural gas systems. EPA 2013 GHG data are also included because they are of a similar vintage to the USLCI (released in 2012) dataset.

2.1.2. Significance beyond natural gas systems

We are interested in LCI data on methane leakage from the natural gas system largely because of the hypothesis that these background data have a large influence on GHG footprint results beyond the natural gas system itself. To test this hypothesis, we investigate the contribution of natural gas system methane leakage

emissions to that point are 1.4% of the mass of the gross withdrawals of methane that reached the distribution system, not that 1.4% of methane is lost at the distribution stage or that 1.4% of gross methane withdrawals have been lost due to distribution and upstream processes. Percent emissions are computed as follows (Equation (1)):

$$\text{percent emissions through stage } n = \sum_{i=1}^n \frac{\text{mass methane emitted at stage } i}{\text{mass methane reaching stage } i} \times \frac{\text{mass methane withdrawn (incl. losses)}}{\text{unit mass methane reaching stage } i} \quad (1)$$

to the GHG footprints of six illustrative materials: plastic, fertilizer, aluminum, steel, electricity, and cement. These materials were chosen because they are themselves common inputs for products throughout the economy. Demonstrating that natural gas system methane leakage matters for the GHG footprints of these materials thus indicates its relevance for GHG footprinting more generally.

2.2. The location of methane leakage

Not all processes that are part of the natural gas supply chain apply to all uses of natural gas. For example, leakage from the natural gas distribution system (a low-pressure network delivering natural gas to typically nonindustrial end users, like homes) does not in most cases affect the carbon intensity of natural gas-fired electricity from power plants. Most natural gas-fired power plants are supplied from the high-pressure transmission system either directly or via high pressure laterals (personal communication, Dynegy Investor Relations, March 2018). We illustrate the relevance of this system structure using natural gas consumption data from the Energy Information Administration (EIA) to provide guidelines on how natural gas end uses map to natural gas system subprocesses (EIA, 2017).

2.3. The influence of global warming potential on methane leakage impact

Use of different GWPs in the literature means that methane emissions reported on a CO₂e basis, even evaluated over the same time horizon, are not necessarily comparable. To illustrate the impact of this instability, we examine methane's GWP in the five Intergovernmental Panel on Climate Change (IPCC) Assessment Reports (the First, Second, Third, Fourth, and Fifth are referred to as FAR, SAR, TAR, AR4, and AR5) (Intergovernmental Panel on Climate Change, 2018). We do not address the separate question of which time horizon to use when comparing climate impacts of methane to carbon dioxide (Farquharson et al., 2017; Gilbert and Sovacool, 2017; Hausfather, 2015; Howarth et al., 2011; Roy et al., 2015).

3. Results and discussion

3.1. Methane leakage in life cycle inventories

3.1.1. Database assumptions

Table 1 summarizes the leakage assumptions in studied LCI databases. The supplementary material (SM) contains calculation details.

For each life cycle stage, leakage is reported as a cumulative mass percentage of gross withdrawals of the methane that reaches each stage. That is, a value of 1.4% under “distribution” means that for natural gas in the distribution system, life cycle methane

Leakage rate estimates for a stage can be computed by subtracting the cumulative losses listed for upstream processes. Note also that gross withdrawals of methane are not equal to gross withdrawals of natural gas because natural gas is not pure methane. Relatedly, the embodied noncombustion GHG intensity of natural gas is also affected by the presence of other GHGs in withdrawn natural gas, including CO₂ and ethane. These nonmethane contributions are outside the scope of this study but could be relevant for some systems, particularly those using natural gas sources containing large mole fractions of CO₂.

Table 1 indicates several issues with the LCI databases. First, all investigated databases likely underestimate methane emissions from natural gas systems: total leakage reported by each database is similar to EPA estimates, which evidence suggests are too low (e.g., Alvarez et al., 2018). Also, they disagree. For example, data from ecoinvent (dated 2018) are much different from USLCI data, even though documentation for ecoinvent suggests its values are based on the USLCI. USLCI and EIO-LCA data are both based on US federal data from the late 1990s and early 2000s, but leakage rates by process are meaningfully different.

Second, databases have variable coverage of the natural gas system. This matters in part because LCA is sometimes used for hotspot identification, allowing analysts to focus on life cycle stages with the most potential for improvement. For example, even though the EIO-LCA production leakage of 0.57% is not that different from the USLCI production + processing leakage of 0.54%, users would draw very different conclusions about where to focus leakage reduction efforts. Note that none of the investigated databases account for methane leakage associated with nonindustrial end users (for example, residential cooking and heating), though its existence has long been understood (Oliphant, 1994) and can affect the climate implications of appliance choices.

Third, databases include numerous documentation discrepancies and nonintuitive definitions. Minor changes in interpretation or approach result in very different values for Table 1. For example, although ecoinvent 3.5 shows a leakage rate slightly higher than EPA estimates, this value is highly sensitive to a nonobvious parameter related to natural gas production from gas versus oil wells: through ecoinvent 3.3, use of a different value for that parameter, but essentially identical data otherwise, led to implied leakage of 1.2% rather than 1.6%. Even in version 3.5, the parameter does not reflect actual US conditions (see SM, S1.4). In another example, in EIO-LCA, calculating emissions based on the “Pipeline transportation” process suggests transmission-stage leakage of 0.42% (when emissions are allocated to coproducts based on monetary value) to 1.6% (when emissions are allocated to coproducts based on the 2002 EPA Greenhouse Gas Inventory), not the 0.34% implied by decomposing the “Natural gas distribution” sector (see SM, S1.2).

Table 1

Methane leakage as cumulative mass percentage of gross withdrawals of methane reaching a given stage, assuming natural gas progresses through each stage in sequence.

| Data source | Production | Processing | Transmission & Storage | Distribution | End Use |
|----------------------------|--------------------|------------|------------------------|-------------------|------------------|
| Reference estimates | | | | | |
| Alvarez et al. (2018) | 2.0% | 2.1% | 2.4% | 2.5% ^a | n/a ^b |
| EPA (2015) | 0.82% | 0.93% | 1.1% | 1.3% | n/a |
| EPA 2013 | 0.38% | 0.63% | 1.0% | 1.4% | n/a |
| LCA databases | | | | | |
| EIO-LCA ^c | 0.57% | n/a | 0.91% | 1.4% | n/a |
| USLCI | 0.34% ^d | 0.54% | 0.92% | n/a | n/a |
| ecoinvent v3.5 | 1.3% ^e | n/a | 1.6% | n/a | n/a |

^a Note Alvarez et al., 2018 estimates for distribution leakage are based on the 2017 EPA GHGI, which they consider a lower bound for the true value (see Alvarez et al., 2018, S1.5).

^b “n/a” denotes a process that is not explicitly included and where no data are available.

^c Methane leakage from the natural gas system is based on the furthest downstream sector “Natural gas distribution:” see SM, S1.2 for details.

^d The 0.34% value cited is based on the process “natural gas, extracted,” which documentation suggests includes all natural gas production. The process “natural gas, at extraction site” is associated with 1.4% leakage. The distinction between the two is unclear: documentation indicates that the database distinguishes between associated and nonassociated natural gas, but both “natural gas, at extraction site” and “natural gas, extracted” indicate in their “technology description” that the process includes both natural gas from natural gas-only wells (nonassociated) and from oil wells (associated). See SM, S1.3 for details.

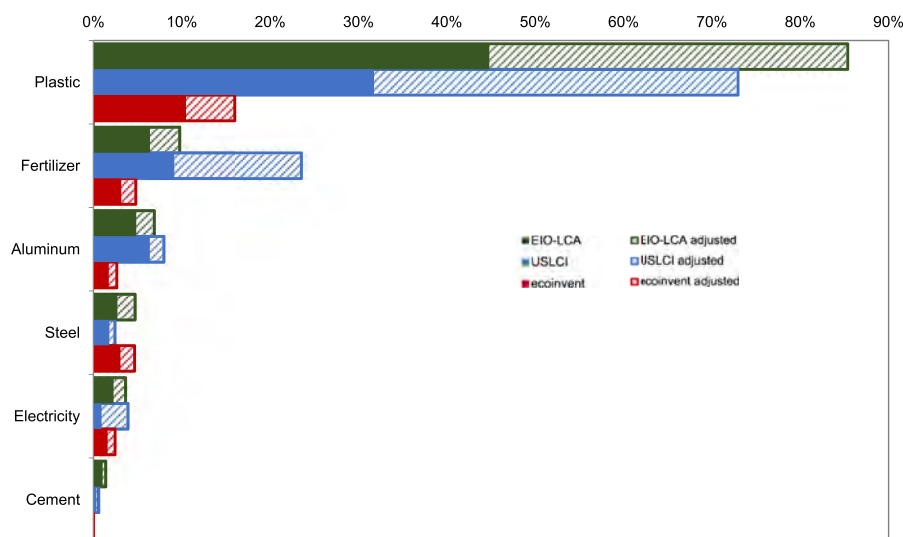
^e Based on life cycle inventory data. Note that the production value is based on the mass-weighted percentage of contributions from “natural gas production” (methane leakage: 1.8%; ecoinvent contribution: 70%) and the natural gas allocation of “petroleum and gas production, on-shore” (methane leakage: 0.1%; ecoinvent contribution, 30%). See SM, S1.4 for details.

In USLCI and ecoinvent, ambiguous process names and definitions can easily lead to unintended choices with large implications for results. In both cases, there are multiple processes for natural gas extraction with unclear or no guidance on which to use. In USLCI, natural gas produced from gas-only wells versus from any well appear to be differentiated by the terms “extracted” (0.34% leakage) and “at extraction site” (1.4% leakage), respectively. Process descriptions are nearly identical, and both imply that all natural gas (both associated and nonassociated) is included. Further, “natural gas, extracted” uses a mass-denominated output while “natural gas, at extraction site” uses a volume-denominated output, so users might choose one or the other based on the units they are using without realizing the data are different. This introduces unnecessary possible confusion.

A similar issue exists for ecoinvent users, who might notice that the cumulative value for leakage post-transmission is smaller than leakage associated with “natural gas, production,” even though the reference flow for the two is the same: 1 m³ of “natural gas, high

pressure.” This discrepancy exists because the post-transmission process is also drawing on a second production process, “petroleum and gas production, on-shore” (see SM, S1.4). The use of the term “natural gas, high pressure” to refer to different systems at different places in the inventory is confusing. As with USLCI, users likely will not anticipate that data associated with “natural gas, production” are very different from those associated with the natural gas output of “petroleum and gas production, on-shore:” life cycle methane leakage for these processes is 1.8% or 0.10%, respectively. Less ambiguous names would help (e.g., calling one flow “natural gas, high pressure, at oil and gas co-production facility” and the other “natural gas, high pressure, at gas production facility”).

Another serious source of confusion is use of the term “natural gas” itself. Without data on the composition of natural gas, converting among mass, energy, and volume units can introduce serious errors. Further, users might reasonably assume that the type of “natural gas” being referenced is relevant to the process at

**Fig. 1.** Contribution of natural gas system methane leakage to greenhouse gas intensity for six basic materials in three life cycle inventory databases.

Notes: Specific processes used to proxy the six materials are found in the SM Data File. “Plastic” is “Plastics material and resin manufacturing” for EIO-LCA and polyethylene terephthalate (PET) for USLCI and ecoinvent. “Fertilizer” is “Fertilizer manufacturing” for EIO-LCA, “nitrogen fertilizer” for USLCI, and “urea ammonium nitrate” for ecoinvent. “Electricity” is the broadest category identified for US electricity in each case. “Adjusted” values show recalculated values assuming that leakage rates in each database matched values from Alvarez et al., 2018.

hand, which is not always the case. For example, in ecoinvent 3.5, the stated mass density of “natural gas, high pressure” of 0.84 kg/m³ implies that the reference flow is raw gas at standard temperature and pressure, not pipeline-quality gas at high pressure (see SM, S1.4). USLCI uses energy rather than mass densities to describe flows but has similar problems (see SM, S1.3). Additionally, databases rarely document whether energy densities are reported on a higher heating value (HHV, sometimes called “gross”) or lower heating value (LHV, sometimes called “net”) basis. The difference between these two measures is about 10%, and the impact might not be noticed outside the energy community (e.g., one should not expect that a polymer chemist performing an LCA of a novel plastics process would know to check for this definitional detail).

3.1.2. Significance beyond natural gas systems

Problems with the characterization of methane leakage from natural gas systems are important for GHG footprinting beyond studies focused on natural gas itself. To illustrate this point, we use the EIO-LCA, USLCI, and ecoinvent databases to estimate natural gas system methane leakage GHG emissions as a percentage of direct process GHG emissions for six major industrial materials: plastic, fertilizer, aluminum, steel, electricity, and cement (Fig. 1).

Calculation details, including the exact processes referenced, can be found in the SM Data File. Fig. 1 uses a GWP of 34 for methane (AR5, 100 year, with climate carbon feedback) and also presents “adjusted” values that show what results would be using leakage rates from a recent empirical study of US natural gas system leakage (Alvarez et al., 2018).

For some materials, embodied methane emissions from natural gas systems are not large compared to direct emissions. For example, cement manufacturing releases substantial process CO₂ emissions and uses little natural gas, so the influence of leaking methane is negligible. For others, however, most notably plastic, embodied methane leakage is substantial.

Fig. 1 suggests that correctly representing natural gas-system methane leakage should be a priority for LCI databases. Only a small number of processes need be updated, a minor task relative to the potential benefits to accuracy. Ensuring these emissions are visible in LCA studies can also help make results actionable. Reducing methane leakage from natural gas systems is likely an easier mitigation opportunity (Gallagher et al., 2015; Gladd, 2016; Hopkins et al., 2016; Lamb et al., 2015; Ravikumar and Brandt, 2017; von Fischer et al., 2017) than reducing byproduct emissions inherent to the production of a product (e.g., from calcining or

| End Use | Description ¹ | 2016 Consump-tion, Bcf | Life Cycle Stages Relevant to End Use | | | | | |
|---|--|------------------------|---------------------------------------|-------------|---------------|---------|---------------|---------------------------|
| | | | Produc-tion | Process-ing | Trans-mission | Storage | Distri-bution | User leakage ² |
| Lease fuel | natural gas used for production | 1,169 | yes | | | | | |
| Plant fuel | natural gas used for processing | 421 | yes | yes | | | | |
| Pipeline and distribution use ³ | natural gas used for transmission and distribution pipelines | 697 | yes | yes | some | some | some | |
| Transmission | not reported separately | n/a | yes | yes | some | some | | |
| Distribution | not reported separately | n/a | yes | yes | yes | yes | some | |
| Residential | natural gas used in residences | 4,345 | yes | yes | yes | yes | yes | yes |
| Commercial | natural gas used in commercial settings | 3,105 | yes | yes | yes | yes | yes | yes |
| Industrial | natural gas used in non-power generation industrial settings | 7,722 | yes | yes | yes | yes | rare | yes |
| Vehicle Fuel | natural gas used in vehicles | 41 | yes | yes | yes | yes | yes | yes |
| Electric Power | natural gas used for electricity generation | 9,983 | yes | yes | yes | yes | rare | yes |
| Approximate end use volume affected, % ⁴ | | 27,486 | ~100% | ~96% | <90% | <90% | <23% | ~87% |

Fig. 2. Relationship between end uses of natural gas in the United States and upstream processes for which leakage and other impacts are embedded. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Notes: Bcf = billion cubic feet. Green/yes = “upstream process for this end use,” yellow/some = “upstream process for some of this end use,” where “some” means that neither condition is unusual, red = “not an upstream process for this end use,” where “rare” means that analysts should assume the upstream process does not apply unless they specifically know about an unusual situation. Source: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.

¹Formal definitions at https://www.eia.gov/dnav/ng/TblDefs/ng_cons_sum_tbldef2.asp.

²All users have the potential to emit fugitive (leaked) methane. These emissions vary widely by customer type and by specific customer: averages should be used very carefully, with effort to match the leakage rate to the end use type. Natural gas system fuel use (i.e., lease, plant, and pipeline and distribution consumption) is assumed not to have additional end-use leakage not accounted for as a system leakage.

³Pipeline use is not differentiated between the transmission and distribution system. Given common uses of natural gas for compressor stations along the pipeline route, natural gas used for these purposes will be subject to some leakage from the systems they support (i.e., transmission or distribution) as well as upstream emissions.

⁴Approximate; exact relationships between users and the natural gas system are not clearly known. For example, some industrial users might be located on distribution lines.

combustion) or unintentional emissions in more dispersed settings (e.g., methane emissions from abandoned coal mines or nitrous oxide emissions from fertilized soils).

3.2. The location of methane leakage

Natural gas has unusually diverse consuming sectors: in the US, 40% is used for electricity generation and 30% each for industrial and residential/commercial uses (EIA, 2017). For LCA, this matters not only because it means that natural gas system methane leakage has pervasive GHG footprint implications (see Section 3.1.2), but also because not all parts of the natural gas supply system are used to serve all end users. Correct representations of a product system include methane leakage only from those upstream processes that are invoked by the product system. Studies of methane leakage often do not explicitly clarify which processes are appropriate for which types of end use, so this section provides rules of thumb for modeling the natural gas system.

Some processes are common to essentially all uses of natural gas. These include extraction, processing, and transmission through high pressure pipelines. Emissions from these processes can vary (e.g., by basin of origin, processing plant, or pipeline), but all natural gas users connected to the same infrastructure will induce the same upstream impacts.

Other processes are not common to all uses. The most significant divergence is that some end uses are served by low-pressure distribution systems downstream of high-pressure transmission systems, while others draw on the high-pressure system directly. Although both the transmission and distribution systems are sometimes called “pipelines” or “transportation,” they are separate systems. Thus, distribution leakage should not be allocated to users supplied directly by the transmission system. A rule of thumb is that natural gas used for power plants, industrial heat, and chemical plant feedstocks generally does not pass through the distribution system, while natural gas used for commercial and residential purposes generally does (Fig. 2, and see SM, S2). The most decision-relevant application of this observation is for natural gas-fired power plants, which are rarely fed by distribution lines, and which have frequently been compared to coal-fired power on the basis of relative carbon emissions. Given methane’s high GWP, incorrectly including distribution leakage for natural gas-fired power can lead to nonnegligible overestimates of GHG intensity (Alvarez et al., 2012).

We recommend that authors explicitly state which natural gas system processes are included in analysis, rather than citing an overall leakage rate. For high resolution studies, note that actual (rather than system-average) leakage can be highly site specific given different use of technologies, levels of training, safety and operational practices, year and/or season, legal context, company practice, or geology and land characteristics. Customer-side leakage is not well characterized by the empirical literature.

3.3. The influence of global warming potential on methane leakage impact

The scientific community’s estimate of methane’s GWP has not yet stabilized. Notably, published estimates have tended to increase over time, both for 20- and 100-year estimates (Fig. 3). For methane, IPCC-estimated GWP values that include climate-carbon feedback are slightly higher than GWP values that do not include this feedback, which is intended to account for inconsistent estimates of GWP for the reference gas (CO₂) versus other species (Gasser et al., 2017). The current IPCC estimate for methane’s 100-year GWP (with climate-carbon feedback) is about 60% higher than the 1996 estimate and about 35% higher than the 2007 estimate; for

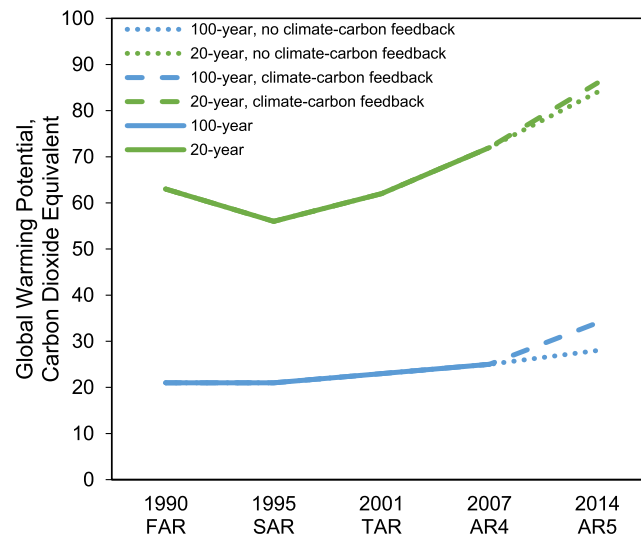


Fig. 3. Estimated global warming potential of methane by IPCC assessment report. Data source: Intergovernmental Panel on Climate Change (2018).

the 20-year GWP, the current estimate is about 50% higher than the 1996 estimate and 20% higher than the 2007 estimate. The anticipated release of the Sixth Assessment Report in 2022—nearly ten years after the release of the current Fifth Assessment Report (AR5)—might update GWP estimates again.

How much does GWP matter? Using a GWP of 25 (100-year, AR4), the 2015 GHGI estimates that natural gas systems accounted for 2.8% of total US GHG emissions (EPA, 2017). Simply updating the GWP to 34 (100-year, AR5 with climate-carbon feedback) raises this estimate to 3.6% of total US GHG emissions. Updating both GWP and natural gas system leakage rates to reflect state of the science estimates (Alvarez et al., 2018) suggests that methane leakage from natural gas systems alone accounts for 7.1% of total US GHG emissions—2.5 times the recorded estimate (EPA, 2017). Researchers using CO₂e-based literature estimates for methane impacts should take care to identify and harmonize GWP assumptions from previously published work. Especially for studies that directly address natural gas systems, conducting GWP sensitivity analysis is advisable.

4. Conclusion

The impact of methane leakage from natural gas systems is systematically underestimated and imprecisely characterized, which affects GHG footprints across product systems. Underestimated natural gas system methane leakage and low GWPs are both significant. LCA databases often underestimate leakage through key life cycle stages even relative to recorded estimates, and the connection between database estimates and relevant data is frequently unclear. The small number of processes involved, and the large impact to product LCA uncertainty, makes natural gas system methane leakage a priority target for data quality assurance in inventory databases. Meaningful improvements can be made with attention to the issues of leakage rates, system boundaries, and GWP described in this work.

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Appendix A. Supplementary data

Supplementary data related to this article can be found at <https://doi.org/10.1016/j.jclepro.2019.03.096>.

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Attachment 2



Total methane emission rates and losses from 23 biogas plants

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ABSTRACT

Methane losses from biogas plants are problematic, since they contribute to global warming and thus reduce the environmental benefits of biogas production. Total losses of methane from 23 biogas plants were measured by applying a tracer gas dispersion method to assess the magnitude of these emissions. The investigated biogas plants varied in terms of size, substrates used and biogas utilisation. Methane emission rates varied between 2.3 and 33.5 kg CH₄ h⁻¹, and losses expressed in percentages of production varied between 0.4 and 14.9%. The average emission rate was 10.4 kg CH₄ h⁻¹, and the average loss was 4.6%. Methane losses from the larger biogas plants were generally lower compared to those from the smaller facilities. In general, methane losses were higher from wastewater treatment biogas plants (7.5% in average) in comparison to agricultural biogas plants (2.4% in average). In essence, methane loss may constitute the largest negative environmental impact on the carbon footprint of biogas production.

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1. Introduction

Biogas from anaerobic digestion, using various substrates such as manure, food waste, organic industrial waste and sludge from wastewater treatment, may result in several greenhouse gas (GHG) mitigation effects, including fossil fuel substitution, the possible balancing of energy sources in a supply system with a high proportion of wind and solar power and a reduction in methane (CH₄) emissions from manure management (Clemens et al., 2006; IPCC, 2011; Sommer et al., 2004). Fugitive CH₄ emissions from biogas plants, however, will reduce the environmental benefits of biogas production, mainly because of the relatively high global warming potential of CH₄, in that releasing just 1 kg of CH₄ into the atmosphere has the same effect with regards to global warming as the release of 28 kg of carbon dioxide (CO₂) integrated over a 100-year period (not including climate feedback) (Myhre et al., 2013). Data on the magnitude of these emissions are sparse, which in turn causes uncertainty with regards to the environmental assessment of biogas production concerning global warming (Meyer-Aurich et al., 2012; Møller et al., 2009). Recent studies suggest that the extent of CH₄ emissions expressed as a fraction of production lost to the atmosphere (also referred to as “CH₄ loss”) may vary between facilities. Liebetrau et al. (2013), for instance, monitored CH₄ emissions from ten German biogas plants, using an on-site approach where individual leaks were identified and emission rates were subsequently measured. It was found that CH₄ emis-

sions relative to the energy output of the biogas plants varied by approximately one order of magnitude between plants, and that open digestate storage tanks in many cases were the most significant emission source. Other sources of CH₄ emission from biogas plants may include unburnt CH₄ from gas engine exhausts, pressure relief valves, biogas upgrading units, ventilation from buildings, leaks in pipes, tanks, etc. (Kvist and Aryal, 2019; Angelidaki et al., 2018; Fredenslund et al., 2018; Liebetrau et al., 2013; Reinelt et al., 2017, 2016; Samuelsson et al., 2018).

An important step in understanding and subsequently reducing CH₄ emissions in the biogas sector is the reliable identification and quantification of single emission sources and the quantification of overall plant emissions. In general, two main approaches can be used for gas emission quantification: on-site and ground-based remote sensing approaches. The on-site approach measures emissions from various single sources at the plant, and it is the method most commonly used (Reinelt et al., 2016; Daniel-Gromke et al., 2015; Westerkamp et al., 2014; Liebetrau et al., 2013). Often a two-step procedure is followed where the first step includes a leakage search performed by using infrared cameras or handheld methane analysers. The second step includes quantification of each identified leakage or emission source often using the stationary or dynamic flux chamber technique. The ground-based remote sensing approach includes different methodologies and measures emissions from a good distance (for example one kilometre) away from the plant, thus providing plant-integrated emission numbers (Fredenslund et al., 2018; Delre et al., 2017; Groth et al., 2015; Yoshida et al., 2014; Hrad et al., 2014; Westerkamp et al., 2014; Flesch et al., 2011). Ground-based remote sensing techniques

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encounter inverse dispersion techniques using for instance open-path lasers and tracer gas dispersion methods. Recent measurement comparison studies have found that methods measuring the plant's total CH₄ emission often result in a higher emission rate in comparison to on-site measurements, where the total emission is obtained by summing up those measured from single sources (Fredenslund et al., 2018; Reinelt et al., 2017). The reason for the discrepancy between on-site and ground-based remote sensing approaches is most likely that single sources are overlooked and/or not identified, or they are technically not quantifiable when using a particular measurement technique (e.g. open tanks). For GHG emission reporting or environmental assessment, the plant's total emissions are important; however, if the purpose of measuring CH₄ emissions at a biogas plant is to identify mitigation options, and thereby provide options to improve the environmental benefits of biogas production, on-site methods are needed.

The objective of this study was to quantify CH₄ emission rates and losses from full-scale biogas plants. The study focused primarily on large, centralised, manure-based biogas plants, which produce the bulk of biogas in Denmark. Production capacity at this type of facility was in the expansion phase nationally at the time of this study. In addition, CH₄ emission rates and losses were measured at biogas plants located at wastewater treatment plants (WWTPs). Landfill gas extraction and utilisation sites were not included. The paper compiles the results taken from several biogas plants, in order to provide an estimate of CH₄ losses from biogas production and to assess the importance of minimising this issue. CH₄ emissions were measured using the tracer gas dispersion method, which measures plant-integrated emission rates. The environmental importance of fugitive CH₄ emissions from biogas plants was evaluated by performing CO₂ footprint calculations for a generic, manure-based agricultural biogas plant.

2. Methodology

2.1. Site descriptions

The biogas plants included in this study all utilise continuously stirred anaerobic digesters to produce biogas, and they all are commercially operated facilities. They varied in terms of feedstocks, size, rate of gas production, type of gas utilisation and other factors. Table 1 provides an overview of the main characteristics of the plants.

Thirteen of the biogas plants (plants 1–13) are categorised herein as “agricultural”, which means that the feedstocks consist mainly of manure, energy crops and agricultural waste, though they can also receive other feedstocks such as slaughterhouse waste or food waste. Out of the 13 agricultural plants, nine receive manure as the main feedstock (>75% of dry matter input is manure), whereby organic waste (organic industrial waste and/or food waste) is used as a supplement to increase gas production. Two biogas plants (plants 8 and 12) rely on energy crops (grass, maize silage and forage rye), one (plant 5) receives mainly organic waste (~80% of dry matter input) but also receives manure and one plant (plant 13) mainly uses food waste. Plant 13 (and possibly also plant 5) could depending on definition be termed a waste treatment biogas plant as it mainly treated slaughterhouse waste, food industry waste and household food waste. However, as this plant was the only one of this type and also as the generated digestate is spread on farmland, the plant was included in the agricultural biogas plant category.

Five of the agricultural biogas plants (plants 1, 2, 5, 6 and 8) were recently constructed (constructed in 2013 or later), whereas the remaining agricultural plants generally were constructed in the 1980s or 1990s. For a number of reasons, the 2000s saw very

low levels of investment in Danish biogas production (Raven and Gregersen, 2007), whereas increases and diversification in subsidies in recent years have led to a “second wave,” with most new production capacity emanating from large facilities that upgrade and inject the biogas into the Danish natural gas distribution grid. At the smaller and older plants, it is more common that the biogas is utilised on-site in a combined heat and power (CHP) unit.

Biogas plants 14–23 are categorised herein as “wastewater treatment biogas plants”. These plants utilise sludge from wastewater treatment to produce biogas, and they are all located on the grounds of the WWTP from where the sludge originates. They can thus be considered part of a larger plant, the primary function of which is to remove pollutants from wastewater before discharge to a recipient, with energy production as secondary function. The biogas plants categorised as “agricultural biogas plants” all rely on gas production for revenue. Although the wastewater treatment biogas plants receive revenue from their gas production, their primary function is to stabilise and reduce the volume of sludge, and thereby the costs of further sludge treatment. The WWTPs may thus arguably have less incentive to minimize loss of methane compared to the agricultural biogas plants.

The size of the plants varied in size in terms of treated feedstocks, from 30,000 to 600,000 tonnes (wet weight) per year for agricultural biogas plants, while the WWTPs treated between 60,000 and 805,000 PE, which corresponded to a load to the on-site biogas plants of between 3,000 and 112,000 tonnes (wet weight) per year.

The biogas plants differ with regards to gas utilisation (Table 1). At 12 plants, all or some of the produced biogas is utilised on site in a CHP unit. At plants 3, 4 and 7 some of the gas (~20–30%) is used on site in a CHP unit providing process heat for the biogas reactors. The generated electricity is sold to the grid. The remaining part of the gas is routed off site to a nearby power plant (where it is used in a CHP unit). At eight plants, all or some of the biogas is upgraded to biomethane, using technologies such as water scrubbers or chemical scrubbers. At these facilities, the gas is either compressed and transported off site or is injected into a natural gas distribution network. At four plants (5, 11, 14 and 21), all gas utilisation occurs off site. An example of this type is plant 5, where the biogas is led to a nearby power plant (and used in a CHP unit) to generate electricity to the grid and heat to a district heating network.

Open digestate storage units may be significant emitters of CH₄ from biogas plants (Samuelsson et al., 2018; Reinelt et al., 2017; Baldé et al., 2016; Liebetrau et al., 2013). Table 1 lists those facilities, which store digestate in open tanks on site. All biogas plants were equipped with gas storage units with capacities typically corresponding to ~1 to 2 days gas production.

In all, the 23 biogas plants included in this study represent a variety of continuously stirred reactor biogas plant types with regards to amounts of feedstock utilised, feedstock types, gas production rates and gas utilisation.

2.2. Tracer gas dispersion method

CH₄ emission rates from each biogas plant were quantified using a tracer gas dispersion method, whereby a gaseous tracer (here acetylene gas – C₂H₂) is continuously released at the biogas plant, and concentrations of CH₄ and C₂H₂ are then measured while traversing the CH₄/C₂H₂ plume at distances up to ~2 km away, using a vehicle-mounted, high-precision gas analyser. The method has been applied to quantify fugitive emissions from various facilities such as landfills, composting facilities, WWTPs and biogas plants (Andersen et al., 2010; Fredenslund et al., 2018; Münster et al., 2014; Scheutz et al., 2011; Yoshida et al., 2014). An advantage of this method compared to on-site methods, where emission sources are quantified individually, is the measurement

Table 1
Overview of the main characteristics of the investigated biogas plants.

| Agricultural biogas plants | Type of feedstock and annual total amount treated at the plant (in tonnes wet weight per year) | On site gas utilisation (CHP ¹ /biogas upgrade) | Digestate storage (open/closed) |
|------------------------------------|---|--|---------------------------------|
| 1* | Manure, maize silage, organic waste (600,000) | Biogas upgrade: chemical scrubber, gas grid injection | Closed |
| 2* | Manure, slaughterhouse waste (240,000) | Biogas upgrade: water scrubber, gas grid injection | Closed |
| 3 | Manure, organic waste (300,000) | CHP (partly off site) | Closed |
| 4 | Manure, slaughterhouse waste, other organic waste (235,000) | CHP (partly off site) | Closed |
| 5* | Industrial waste, manure (200,000) | None – routed for off-site use in a CHP | Closed |
| 6* | Manure, maize silage (118,000) | Biogas upgrade: chemical scrubber, gas grid injection | Closed |
| 7 | Manure, slaughterhouse waste, other organic wastes (225,000) | CHP (partly off site) | Closed |
| 8* | Maize silage, forage rye | CHP and biogas upgrade: chemical scrubber, gas grid injection | Closed |
| 9 | Manure, organic waste, maize silage (170,000) | CHP | Closed |
| 10 | Manure, organic waste (37,000) | CHP | Closed |
| 11 | Manure, maize and grass silage, glycerol (30,000) | None – routed for off-site use in a CHP | Closed |
| 12 | Grass and maize silage, manure | CHP | Open |
| 13 | Organic waste (slaughterhouse waste, industrial food waste and household food waste) (104,000) | Biogas upgrade: chemical and water scrubber, gas to vehicle fuel | Open |
| Wastewater treatment biogas plants | Feedstock (amount given in person equivalent) | On site gas utilisation (CHP ¹ /biogas upgrade) | Digestate storage (open/closed) |
| 14 | Sludge from wastewater treatment (750,000 PE ²) | None – routed for off-site biogas upgrading | Closed |
| 15 | Sludge from wastewater treatment (265,000 PE) | CHP | Open |
| 16 | Sludge from wastewater treatment (150,000 PE) | CHP | Closed |
| 17 | Sludge from wastewater treatment (420,000 PE) | Biogas upgrade: chemical scrubber, gas grid injection | Closed |
| 18 | Sludge from wastewater treatment (95,000 PE) | CHP | Closed |
| 19 | Sludge from wastewater treatment (60,000 PE) | CHP | Open |
| 20 | Sludge from wastewater treatment (125,000 PE) | CHP | Closed |
| 21 | Sludge from wastewater treatment (805,000 PE), industrial food waste and sewage sludge from small WWTPs | None – routed for off-site biogas upgrading, gas to vehicle fuel | Open |
| 22 | Sludge from wastewater treatment (95,000 PE), food waste | Biogas upgrade: chemical scrubber, gas to vehicle fuel | Open |
| 23 | Sludge from wastewater treatment (120,000 PE) | Biogas upgrade: chemical scrubber, gas to vehicle fuel | Open |

¹ CHP: Combined heat and power.

² PE: Person equivalent.

* Constructed in 2013 or later.

of the biogas plant's total CH₄ emission, with little risk of underestimating them due to undetected emission sources (Fredenslund et al., 2018).

The method and instrumentation are described in detail in Mønster et al. (2014) and Yoshida et al. (2014). The overall error of the method has been the subject of a recent validation study, and it was found very likely to be less than 20% (Fredenslund et al., 2019). The potential error of the tracer gas dispersion measurement technique was determined to 15% by establishment of an error budget including the analytical error, error in the tracer gas release rate, data processing, and error in tracer gas placement and source simulation. The error of a measurement is the combined error of the method and the variability of the quantification, which was found to be about 20% in a controlled release test and comparable to the error obtained by comparison of the measured emission rate and the known controlled release rate (Fredenslund et al., 2019).

Emission rates are calculated using Eq. (1):

$$E_{\text{target}} = Q_{\text{tracer}} \times \frac{\int_{\text{plume start}}^{\text{plume end}} C_{\text{target}} - C_{\text{target, background}} dx}{\int_{\text{plume start}}^{\text{plume end}} C_{\text{tracer}} - C_{\text{tracer, background}} dx} \times \frac{MW_{\text{target}}}{MW_{\text{tracer}}} \quad (1)$$

where E_{target} is the emission rate of CH₄ in kg h⁻¹; Q_{tracer} is the release rate of the acetylene tracer gas in kg h⁻¹; C_{target} and C_{tracer} are the measured downwind concentrations in parts per billion (ppb); $C_{\text{target, background}}$ and $C_{\text{tracer, background}}$ are the measured

background concentrations in parts per billion (ppb) and MW_{target} and MW_{tracer} are the molar weights of the two gases.

The measurements were taken by driving through the downwind plumes several times (typically 10 to 20 traverses per measurement campaign). Each plume traverse resulted in one CH₄ emission measurement, calculated using Eq. (1). The CH₄ emission rate (in kg h⁻¹) was calculated as the average value of the individual plume traverses, and any uncertainty was estimated as the standard error of the mean of the measurements (Fredenslund et al., 2019).

CH₄ loss (%) was determined as the ratio of the measured CH₄ emission to the CH₄ production of the biogas plants, logged the day the measurement was performed.

2.3. Measurement campaigns

The measurements were performed July 2013 through June 2018. At six biogas plants, this happened on a single day, whereas for the remaining 17 plants, measurements were repeated up to a maximum of six days (Table 2).

All measurements were performed using the same analytical equipment and the method described in Section 2.2. The measurements were performed during normal operation of the biogas plants. No malfunctions were reported by the plants for the periods of measurement. As implementation of the method required certain adjustments in each case, some variability with regards to tracer gas release rates and number of release points exists.

Table 2
Overview of measurements performed.

| Plant number | Days of measurement campaigns | Number of plume traverses | Tracer gas release rate (kg C ₂ H ₂ h ⁻¹) |
|---|-------------------------------|---------------------------|---|
| <i>Agricultural biogas plants</i> | | | |
| 1 | 1 | 20 | 2.24 |
| 2 | 2 | 66 | 1.07 |
| 3 | 1 | 14 | 2.29 |
| 4 | 3 | 54 | 1.90 |
| 5 | 2 | 32 | 1.44 |
| 6 | 2 | 42 | 0.97 |
| 7 | 3 | 54 | 0.83 |
| 8 | 5 | 166 | 1.32 |
| 9 | 2 | 39 | 1.24 |
| 10 | 1 | 17 | 0.91 |
| 11 | 2 | 29 | 1.50 |
| 12 | 4 | 138 | 1.51 |
| 13 | 2 | 21 | 0.44 |
| <i>Wastewater treatment biogas plants</i> | | | |
| 14 | 6 | 82 | 0.57 |
| 15 | 1 | 21 | 0.92 |
| 16 | 4 | 63 | 0.51 |
| 17 | 2 | 37 | 1.68 |
| 18 | 2 | 40 | 0.93 |
| 19 | 4 | 89 | 0.48 |
| 20 | 1 | 16 | 0.90 |
| 21 | 1 | 16 | – |
| 22 | 3 | 81 | 0.91 |
| 23 | 3 | 82 | 0.78 |

The average tracer gas release rate varied between 0.11 and 2.29 kg C₂H₂ h⁻¹, and the number of tracer gas release points varied between one and three. The measurement distance varied from a few hundred metres up to more than 1 km, according to the availability of drivable roads downwind and the detectability of elevated concentrations of CH₄ and C₂H₂ in the plume – low emission rates and high wind speeds increase dilution, and so it may be necessary to traverse the plume closer to the source of emission.

2.4. Impact of methane emissions on the overall CO₂ footprint of biogas plants

The impact of CH₄ loss on the overall CO₂ footprint of biogas plants was evaluated by using a calculation model provided by

Table 3
Overview of parameters used in carbon footprint calculations.

| Parameter | Value | Reference |
|---|---|---|
| <i>Emission factors</i> | | |
| Provision of electricity (average) ^a | 0.053 kg CO ₂ -eq. MJ ⁻¹ | Energinet.dk (2018) |
| Provision of electricity (marginal) ^b | 0.24 kg CO ₂ -eq. MJ ⁻¹ | Ea Energianalyse (2016) |
| Provision and consumption of natural gas | 0.057 kg CO ₂ -eq. MJ ⁻¹ | Danish Energy Agency (2018) |
| Provision of heat (district heating, Danish average value) ^c | 0.056 kg CO ₂ -eq. MJ ⁻¹ | Danish Nature Agency (2014) |
| Production of N fertiliser | 7.0 kg CO ₂ -eq. kg N ⁻¹ | Danish Nature Agency (2014) and Wood and Cowie (2004) |
| Production of P fertiliser | 0.5 kg CO ₂ -eq. kg P ⁻¹ | Danish Nature Agency (2014) and Wood and Cowie (2004) |
| Transportation of digestate, manure, etc. | 0.09 kg CO ₂ -eq. tonne ⁻¹ km ⁻¹ | (Danish Nature Agency, 2014) |
| Emission of CH ₄ | 28 kg CO ₂ -eq. kg CH ₄ ¹ | Myhre et al. (2013) |
| Manure management, cattle | –15 kg CO ₂ -eq. tonne manure ⁻¹ | Danish Nature Agency (2014) |
| Manure management, pigs | –23 kg CO ₂ -eq. tonne manure ⁻¹ | Danish Nature Agency (2014) |
| <i>Other factors</i> | | |
| Process heat | 8.4% of energy output | Danish Energy Agency (2017a) |
| Electricity use, biogas plant | 3.7% of energy output | Danish Energy Agency (2017a) |
| Electricity use, biogas upgrade and compression | 5.3% of energy output | Danish Energy Agency (2017a) |
| Electrical efficiency, CHP unit | 44% | Danish Energy Agency and Energinet.dk (2014) |
| Total efficiency, CHP unit | 92% | Danish Energy Agency and Energinet.dk (2014) |

^a Provision of electricity, average: 17% coal, 6% natural gas, 55% wind, hydro and solar, 18% waste incineration, biomass and biogas, 1% oil and 3% nuclear.

^b Provision of electricity, marginal: 80% coal, 15% natural gas and 5% renewables.

^c Average value of Danish district heating networks utilising various energy sources (waste incineration, solar, surplus heat from coal and biomass electricity production and more).

the Danish Ministry of Environment for environmental impact assessments of biogas projects (Danish Nature Agency, 2014). The model considers the following factors in determining the overall CO₂ footprint of biogas plants:

- Substitution of fossil fuels
- Substitution of chemical fertiliser
- Transportation of feedstock and digestate
- Change in manure management compared to conventional storage and use of manure in agriculture (fewer GHG emissions from manure storage at farms when manure is digested before storage)
- Energy use of the biogas plant
- Direct GHG emissions from biogas production and utilisation

Emissions and savings were determined by considering five levels of direct CH₄ loss from an agricultural biogas plant: 1%, 2%, 5%, 10% and 20%. Losses of produced biogas contribute directly (CH₄ emitted into the atmosphere) and indirectly (less substitution of fossil fuel as a result of lost biogas production), so both losses were included in the model.

In this assessment, we considered a generic agricultural biogas plant receiving 50,000 tonnes yr⁻¹ of cattle manure, 60,000 tonnes yr⁻¹ pig manure and 5000 tonnes yr⁻¹ organic waste, which in combination produced 2.2 million m³ CH₄ yr⁻¹. This calculation example is similar to one described by The Danish Nature Agency (2014). Two biogas utilisation options were considered: CHP and biogas upgrade and injection into the natural gas grid.

Table 3 provides an overview of emission factors as well as energy use and CHP energy conversion efficiencies. Two emission factors regarding the use and production of electricity were considered in terms of CHP gas utilisation, namely average and marginal. The average emission factor corresponds to the average emissions associated with the provision of electricity in Denmark, whereas the marginal factor is derived from an estimate of which electricity sources are reduced when production from (for example) biogas plants is increased – also in Denmark. The provision of electricity, on average, consisted of 17% coal, 6% natural gas, 55% wind, hydro and solar, 18% waste incineration, biomass and biogas, 1% oil and 3% nuclear – as reported by the Danish national authority on electricity production (Energinet.dk, 2018), whereas the provision of marginal electricity consisted of 80% coal, 15% natural gas and 5% renewables from a recent study on CO₂ emissions caused by

increasing electricity demand in Denmark (Ea *Energianalyse*, 2016). The differences in energy mix in the provision of average electricity, and provision of marginal electricity cause a relatively large difference in emission factors at $0.053 \text{ kg CO}_2\text{-eq MJ}^{-1}$ (average) and $0.24 \text{ kg CO}_2\text{-eq MJ}^{-1}$ (marginal). In the scenario considering the biogas upgrade, for simplicity we only considered the average emission factor for electricity use. In all scenarios, the consumption of heat by the biogas plant was presumed to be in the form of natural gas. In both CHP scenarios, the same emission factor for heat substitution was used, namely an average value of district heating networks in Denmark.

Both feedstock and digestate were assumed to be transported 5 km to and from the biogas plant. The anaerobic digestion of organic waste and the land application of digestates, and thereby recycling of the contained nutrients, was assumed to result in the reduced use of chemical fertiliser at 10 tonnes N yr⁻¹ and 5 tonnes P yr⁻¹. The nutrient content of the manure was not considered to contribute to the reduced use of chemical fertiliser, since these nutrients would be applied to agricultural land anyway as raw manure without digestion.

3. Results and discussion

3.1. Measured CH₄ emission rates

Table 4 lists the measured CH₄ emission rates and losses for the 23 biogas plants in this study. The table also lists the biogas pro-

duction rate of each plant, which was reported by individual plant operator in each case in the form of average daily production at the time of measurement. In those cases where CH₄ emission rates were measured over several campaigns, the listed CH₄ emission rates, gas production rates and CH₄ losses are average values.

Overall, the average CH₄ emission rates varied between 2.3 and 33.5 kg CH₄ h⁻¹. CH₄ losses (CH₄ emission relative to CH₄ production) varied between 0.4 and 14.9%, with the average being 4.6%. These results are comparable to Liebetrau et al. (2013), who found CH₄ losses from single, dominant sources (CHP units and open digestate storage) equating to between 0.22 and 11.2% of the utilised gas at 10 biogas plants. They are also comparable to the results of a study of a Canadian biodigester, where losses under normal operating conditions corresponded to 3.1% of CH₄ production (Flesch et al., 2011).

In general, CH₄ losses were higher from wastewater treatment biogas plants (average 7.5%) than from agricultural plants (2.4%) (Table 4). At seven of the 23 biogas plants, the average measured CH₄ loss was higher than the overall average (4.6%) (Table 4). Of these seven plants, six were WWTPs. The agricultural biogas plant that emitted more than 4.6% (plant 11, Table 4) actually had the lowest level of biogas production (Table 4). Of the agricultural plants, the highest CH₄ loss was 8.4% (biogas plant 11). The reported loss was based on two measurement campaigns, which both showed high CH₄ emissions. There was no on-site gas utilisation and no open mixing tanks, digestate storage tanks or similar. A specific reason as to why the biogas plant had a higher loss than

Table 4
Overview of measured average CH₄ emission rates and losses.

| Plant number | On-site sources included in the measured emission (CHP or biogas upgrade unit) | Average biogas production kg CH ₄ h ⁻¹ | Average CH ₄ emission rate kg CH ₄ h ⁻¹ | Average CH ₄ loss % | Estimated revenue loss ^e k€ y ⁻¹ | Off-site sources not included in the measured emission (CHP or biogas upgrade unit) |
|--|--|--|--|--------------------------------|--|---|
| 1 | Biogas upgrade unit | 1469 | 6.5 ± 0.6 | 0.4 ± 0.04 | 27.4 ± 2.3 | – |
| 2 ^a | Biogas upgrade unit | 1083 | 19.1 ± 2.5 | 1.8 ± 0.23 | 80.9 ± 10.6 | – |
| 3 | CHP ^f | 888 | 23.2 ± 1.7 | 2.6 ± 0.19 | 98.5 ± 7.2 | CHP |
| 4 | CHP ^f | 858 | 6.4 ± 0.5 | 0.7 ± 0.06 | 27.0 ± 2.0 | CHP |
| 5 | – | 498 | 3.0 ± 0.3 | 0.6 ± 0.06 | 12.9 ± 1.4 | CHP |
| 6 ^a | Biogas upgrade unit | 411 | 10.7 ± 0.5 | 2.6 ± 0.12 | 45.2 ± 2.1 | – |
| 7 ^a | CHP ^f | 404 | 6.4 ± 0.2 | 1.6 ± 0.06 | 27.1 ± 1.0 | CHP |
| 8 | CHP and biogas upgrade unit | 400 | 2.3 ± 0.4 | 0.6 ± 0.10 | 9.9 ± 1.6 | – |
| 9 | CHP | 333 | 14.9 ± 0.9 | 4.5 ± 0.26 | 63.1 ± 3.6 | – |
| 10 | CHP | 234 | 6.1 ± 0.8 | 2.6 ± 0.35 | 26.1 ± 3.5 | – |
| 11 | – | 74 | 6.4 ± 0.4 | 8.6 ± 0.50 | 27.2 ± 1.6 | CHP |
| 12 | CHP | 127 | 2.6 ± 0.4 | 2.1 ± 0.35 | 11.0 ± 1.9 | – |
| 13 ^b | Biogas upgrade unit | 815 | 21.2 ± 3.3 | 2.6 ± 0.40 | 90.0 ± 13.8 | – |
| Plant average CH ₄ loss, agricultural : 2.4% | | | | | | |
| Production weighted average CH ₄ loss, agricultural : 1.7% | | | | | | |
| 14 ^c | – | 440 | 9.8 ± 0.7 | 2.2 ± 0.15 | 41.7 ± 2.8 | Biogas upgrade unit |
| 15 ^a | CHP | 162 | 13.5 ± 0.5 | 8.3 ± 0.33 | 57.3 ± 2.3 | – |
| 16 ^c | CHP | 100 | 2.6 ± 0.4 | 2.6 ± 0.39 | 11.1 ± 1.6 | – |
| 17 | Biogas upgrade unit | 96 | 12.3 ± 1.2 | 12.8 ± 1.29 | 52.0 ± 5.2 | – |
| 18 | CHP | 88 | 8.1 ± 0.5 | 9.1 ± 0.60 | 34.2 ± 2.3 | – |
| 19 ^c | CHP | 85 | 2.6 ± 0.1 | 3.0 ± 0.16 | 11.0 ± 0.6 | – |
| 20 | CHP | 262 | 10.0 ± 1.0 | 3.8 ± 0.38 | 42.5 ± 4.2 | – |
| 21 ^d | – | 525 | 33.5 ± 0.6 | 6.4 ± 0.12 | 142.3 ± 2.6 | Biogas upgrade unit |
| 22 ^c | Biogas upgrade unit | 83 | 10.0 ± 0.6 | 12.0 ± 0.78 | 42.3 ± 2.7 | – |
| 23 ^c | Biogas upgrade unit | 58 | 8.6 ± 0.4 | 14.9 ± 0.72 | 36.5 ± 1.7 | – |
| Plant average CH ₄ loss, WWTP : 7.5% | | | | | | |
| Production weighted average CH ₄ loss, WWTP : 5.8% | | | | | | |
| All biogas plants | | | | | | |
| Plant average CH ₄ loss, all: 4.6% | | | | | | |
| Production weighted average CH ₄ loss, all: 2.5% | | | | | | |

^a Results were partly (first measurement) reported in Fredenslund et al. (2018).

^b Results were reported in Reinelt et al. (2017).

^c Results were reported in Delre et al. (2017).

^d Results were reported in Samuelsson et al. (2018).

^e Considering an estimated revenue of 0.7 €/Nm³ CH₄.

^f About 20–30% of the gas is used in a CHP unit, while the remaining is transported off site.

the average agricultural biogas plant was thus not identified. In general, the CH₄ emission rate relative to production seemed to correlate with the size of the biogas plant (Fig. 1), in that units with the highest gas production emitted proportionally less CH₄ compared to plants with relatively low output. One reason for this finding may be that the larger facilities have more economical resources for maintenance, re-investment and employment of highly proficient plant operators. Another reason may be that the number of potential emission sources (number of process units, pipes, joints, valves, etc.) is not necessarily proportional to the rate of biogas production. There was also the tendency that the larger agricultural plants were built more recently and thus may better represent the most up-to-date technology. CH₄ emission from biogas plants is not regulated directly in Denmark, so no regulatory explanation for the difference in methane loss for small biogas plants compared to larger plants was found. CH₄ losses from plants built within approximately the last 5 years (plants 1, 2, 5, 6 and 8) were relatively low (0.4, 1.8, 0.6, 2.6 and 0.6%, respectively). Two of the 13 agricultural plants were solely energy plants, where the input was mainly crops grown specifically for energy production, and both had CH₄ losses lower than the average for all plants.

As mentioned previously, agricultural biogas plants rely mostly on revenue from energy production for their existence, whereas energy production is a secondary activity in the case of wastewater treatment biogas plants. The economic incentive to maximise energy production, and therefore minimise leaks, may therefore be stronger for agricultural biogas plants. Finally, it should be noted that in this study total CH₄ emissions from the plants were measured. Wastewater treatment plants are more complex in structure than agricultural biogas plants, as they also have a water treatment operation in addition to sludge management and biogas production. Therefore, CH₄ emission rates measured at wastewater treatment biogas plants could also encounter CH₄ emissions from the water treatment line and from the open storage of sludge, which is more common at WWTPs in comparison to agricultural plants. However, at WWTPs, the main CH₄-emitting source will be biogas activities, even though CH₄ emissions can also occur from the plant inlet and from aeration tanks. Samuelsson et al. (2018) quantified CH₄ emissions from various unit processes at a WWTP and found that overall, about 81% of the CH₄ emissions quantified on site were released from the sludge treatment line. Delre et al. (2017) came to a similar conclusion based on on-site screenings of atmospheric CH₄ concentrations, where the highest elevated intensities were seen in the vicinity of sludge treatment activities. Sludge (un-digested or digested) storage in open tanks or basins can be a potential source of CH₄, which is challenging to quantify due to the large open surface area. At some of the WWTPs, open digestate storage of sludge could explain (but only partly) the higher emission rates. As an example, the average CH₄

loss at WWTPs with open storage was 9.2% in comparison to plants without on-site open storage (6.1%).

Finally, it should be noted that at four of the plants (5, 11, 14 and 21) all gas utilisation occurs off site and at three of the plants part of the gas utilisation (~70–80%) occurs off site (plants 3, 4 and 7). For these plants, any CH₄ emission from the off site utilisation was therefore not included in the measured total CH₄ emission and thus the total CH₄ emission from the combined production and utilisation could be higher than the values reported in Table 4. At two of the plants (WWTPs 14 and 21) the generated biogas is routed off site for biogas upgrading. CH₄ emission factors from biogas upgrading units vary depending on technology applied. An average CH₄ slip of 0.81% was recently reported based on measurements of nine biogas upgrading units located in Denmark (Kvist and Aryal, 2019). The highest (1.97%) CH₄ slip was detected in the water scrubber methane upgrading technology, while the lowest (0.04%) CH₄ loss was detected in an amine based chemical scrubber (Kvist and Aryal, 2019). At five of the plants (agricultural plants 3, 4, 5, 7 and 11) the generated biogas is used (or partly used) in a CHP located off site. Liebetrau et al. (2013) found biogas co-generation units to emit on average 1.74% of the utilized methane with losses ranging from 0.40 to 3.28% (based on measurements at 10 biogas plants).

3.2. Contribution of methane emissions to the overall CO₂ footprint

Applying the methodology described in Section 2.4, the importance of various levels of CH₄ loss on the environmental performance of an agricultural biogas plant was assessed (Fig. 2). The impact in terms of GHG emissions (reported in CO₂-equivalents) of the different levels of CH₄ loss was assessed for three scenarios. In scenario A, biogas is upgraded to biomethane and substitutes for natural gas. In scenario B, biogas is utilised in a CHP unit, whereby electricity is supplied to the grid, and heat is used for district heating. In scenario C, the average emission factor regarding the production and consumption of electricity was used, as described in Section 2.4. In scenario C, biogas is also used in a CHP unit, but here the marginal emission factor for the production and consumption of electricity (Section 2.4) was used, meaning in this case that electricity production replaces more fossil fuel.

In all scenarios, CH₄ losses from biogas plants had a significant effect on the overall CO₂ footprint (Fig. 2). At 5% loss, CH₄ emissions make a greater contribution to the CO₂ footprint burden (positive CO₂ emission) compared to the other individual positively contributing emissions, namely energy consumption and the transportation of feedstock and digestate in all scenarios.

In scenarios A and B, a CH₄ loss of 20% caused the net GHG emissions to be positive, meaning that the biogas plant can be considered a net emitter of GHG, despite the substitution of fossil fuels, the reduction of GHG from manure storage and the substitution of chemical fertiliser. This is seen similarly in Table 5, where emission factors are listed for the three scenarios and five levels of CH₄ loss. These emission factors are the calculated net GHG emissions of the biogas production per one tonne of feedstock (wet weight) derived from the calculation example described in Section 2.4. The emission factors vary significantly in cases where CH₄ loss is relatively low (1–2%), to cases where the loss is relatively high (10–20%). The results also show that the emission factors in scenario B (CHP, average) vary highly in comparison to scenario C (CHP, marginal). The cause of this difference is the much lower electricity emission factor in the average mix of electricity sources (0.053 kg CO₂-eq. MJ⁻¹) compared to the marginal emission factor (0.24 kg CO₂-eq. MJ⁻¹) (Table 3).

The average CH₄ emission from the 13 agricultural biogas plants equated to 2.4% of the daily plant production (Table 4). Comparing this average CH₄ emission to implications on the total CO₂ foot-

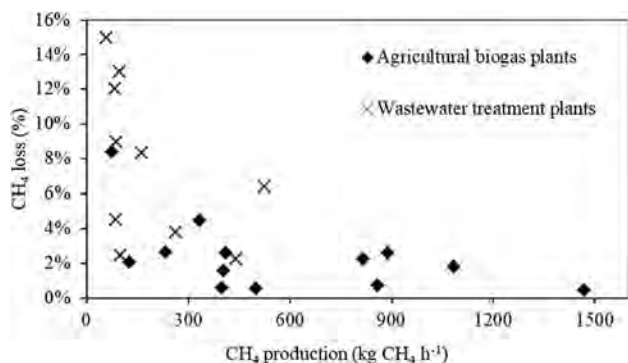


Fig. 1. Average CH₄ loss as a function of the average gas production at biogas plants.

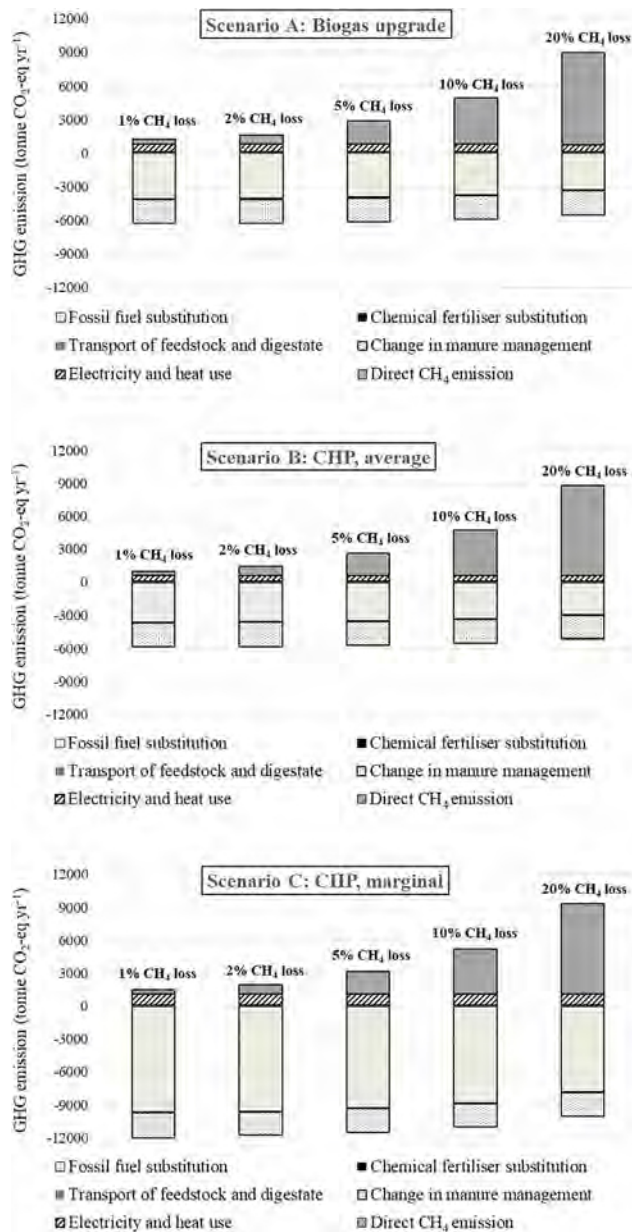


Fig. 2. Greenhouse gas (GHG) emissions calculated for an agricultural biogas plant, considering different biogas utilisation scenarios and five levels of methane (CH₄) loss. CHP: Combined heat and power.

print shown in Fig. 2, this relatively low loss indicates that the production of biogas is a net benefit with regards to GHG emissions. Since CH₄ emission rates compared to production varied greatly between biogas plants (Table 4), it is also likely that the CO₂ footprint of each individual plant will do so, too. Biogas plants, where the loss is particularly high (more than ~15%), may be net emitters of GHG, which underlines the importance of minimising CH₄ emissions from these facilities.

Table 5

Greenhouse gas emission factors (kg CO₂-eq tonne feedstock⁻¹) calculated for different biogas utilisation scenarios and five levels of CH₄ loss. A negative value implies an overall benefit to the environment, while a positive value implies an overall burden to the environment.

| Scenario | 1% loss | 2% loss | 5% loss | 10% loss | 20% loss |
|----------------------------|---|---------|---------|----------|----------|
| | (kg CO ₂ -eq tonne feedstock ⁻¹) | | | | |
| Scenario A: Biogas upgrade | -44.6 | -40.7 | -29.0 | -9.4 | 29.7 |
| Scenario B: CHP, average | -42.1 | -38.2 | -26.5 | -7.0 | 32.0 |
| Scenario C: CHP, marginal | -89.7 | -85.3 | -72.0 | -49.9 | -5.7 |

In this study, the carbon footprint of WWTPs was not determined, mainly because the primary purpose of a WWTP is not biogas generation but wastewater treatment, which implies that the services provided by the two types of plants are not comparable. Furthermore, not only CH₄ but also N₂O (another potent GHG) is emitted from WWTPs primarily from the water treatment line, which needs to be included in footprint calculations. For an evaluation of the carbon footprint for biogas plants located at WWTPs, we instead refer to a recent study by Delre et al. (2019), which assessed carbon footprints for seven Scandinavian WWTPs, including some of the plants in this study. The study showed net carbon footprint values between 0.15 and 0.66 kg CO₂ eq. (Mg of input material)⁻¹, depending on the treatment facility. Direct CH₄ and N₂O emissions were the main contributors to the carbon footprint, accounting for between 44 and 71% of the total emission burden (Delre et al., 2019).

3.3. Fugitive methane emissions from Danish biogas production

Danish biogas producing facilities can be divided into four categories: agricultural (centralised and farm-scale) biogas plants (mainly treating manure), industrial biogas plants, wastewater treatment biogas plants (treating sewage sludge) and landfill gas. In total, 165 biogas-producing plants exist in the form of 82 agricultural (28 centralised and 54 farm-based), 51 wastewater treatment biogas, five industrial biogas and 27 landfill gas facilities (Danish Energy Agency, 2017b). The production of biogas has increased from 266 TJ (~5328 tonnes of CH₄) in 1990, to 7899 TJ (~157,985 tonnes of CH₄) in 2016 (Nielsen et al., 2018). In 2016, 86% of the generated biogas was based on manure/organic waste, 12% on sludge from wastewater treatment and only 2% came from landfills (Nielsen et al., 2018). Biogas production at the plants from which emissions were measured in this study represented about between 41% (agricultural) and 45% (WWTPs) of the annual Danish total (in 2016). National CH₄ emissions from Danish biogas production were estimated by applying the measured CH₄ emission factors to nationally generated CH₄ production, distinguishing between emission factors from agricultural and WWTP biogas plants, respectively. Two sets of CH₄ emission factors were used: a plant average and a weighted production average. The plant average was an average of CH₄ losses measured at the plants (sum of CH₄ losses divided by the number of plants), whereas the weighted production average was the sum of all CH₄ emission rates divided by the sum of all plants' CH₄ production rates (cf. Table 4). The plant average represents the biogas technology, whereas the weighted production average represents the combined biogas production in Denmark. Table 6 shows the estimated national CH₄ emissions (tonnes CH₄) for agricultural and WWTP biogas plants, and the total. The total estimated CH₄ emissions are between 3409 and 4683 tonnes, with emissions from agricultural biogas plants making up 6870%, while 30–32% originate from WWTPs (Table 6).

The 2006 IPCC Guidelines consider emissions from biogas plants (anaerobic digestion) as part of the waste sector. According to the IPCC Guidelines, emissions of CH₄ from biogas facilities, due to unintentional leakages during process disturbances or other unexpected events, will generally be between 0 and 10% of the

Table 6

Estimated national CH₄ emissions from the anaerobic digestion of organic waste in agricultural biogas plants and biogas plants at wastewater treatment plants (WWTPs) in 2016 (excluding landfill gas). Numbers in brackets give the percentage out of total CH₄ emissions (excluding landfill gas).

| Biogas plant type | Agricultural biogas plants | WWTP biogas plants | Total |
|---|----------------------------|--------------------|---------|
| CH ₄ production, tonnes | 135,867 | 18,958 | 154,825 |
| CH ₄ emission, tonnes (Plant average; EF _{Agricultural} = 2.4% and EF _{WWTP} = 7.5%) | 3261 (70%) | 1422 (30%) | 4683 |
| CH ₄ emission, tonnes (Production average; EF _{Agricultural} = 1.7% and EF _{WWTP} = 5.8%) | 2310 (68%) | 1100 (32%) | 3409 |

amount of CH₄ generated. In the absence of further information, a default value of 5% for the CH₄ emissions should be used (Eggleston et al., 2006).

CH₄ emissions from biogas production are reported in the Danish national greenhouse gas inventory as being a part of the waste sector's GHG emissions (Nielsen et al., 2018). CH₄ emissions were reported at 6635 tonnes in 2016, using an average adopted emission factor (EF) set equal to 4.2% for all types of biogas plants. This emission factor was based on a Danish project where CH₄ leakages were measured at nine biogas plants in Denmark, using on-site point measurement methods (Danish Energy Agency, 2015). Five of the plants were small, single-farm plants, while the other four were larger, centralised agricultural plants. The results were that the CH₄ losses varied from nil to 10% of production, resulting in a weighted average of 4.2%, which was adopted in the national inventory reporting for biogas production independently of the type of biogas plant. Our study shows a lower emission factor from agricultural plants, whereas the emission factor from biogas plants at WWTPs is higher than 4.2%. However, as the share of biogas generated at WWTPs is lower (12%) in comparison to agricultural plants (86%), the combined CH₄ emissions from these two types of facilities are almost comparable, resulting in a national emission of 3409 to 4683 tonnes of CH₄, which is close to the nationally reported figure.

The Danish Biogas Association is a trade organisation representing the Danish biogas sector, with members including plant owners, suppliers, agriculture and energy companies. Within the last few years, this organisation has initiated a voluntary measurement programme with the aim of keeping CH₄ loss at a minimum via a target of 1% loss for the sector. Our results indicate that some improvements are needed to reach this goal. However, the production weighed average loss was just 1.7% for the agricultural biogas plants, where most gas is produced and where production capacity is expanding, and thus the 1% target for the sector as a whole seems to be within reach. However, at plant level, emission rates are higher.

4. Conclusions

Methane losses were measured at 23 biogas plants and found to vary between 0.4 and 15.0% of the production total. Comparing those measured losses to an evaluation of the impact of methane loss on the overall carbon footprint of biogas production, it may be the case that methane loss is the largest positive contributor to greenhouse gas emissions for many biogas plants compared to other factors, such as energy use and the transportation of biomass.

Acknowledgements

This paper presents results from several research projects as well as measurements performed to develop a voluntary measure-

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Attachment 3

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At scale, renewable natural gas systems could be climate intensive: the influence of methane feedstock and leakage rates

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Abstract

Renewable natural gas (RNG) is a fuel comprised of essentially pure methane, usually derived from climate-neutral (e.g. biogenic or captured) carbon dioxide (CO₂). RNG is proposed as a climate friendly direct substitute for fossil natural gas (FNG), with the goal of enabling diverse natural gas users to continue operating without substantial infrastructure overhauls. The assumption that such substitution is climate friendly relies on a major condition that is unlikely to be met: namely, that RNG is manufactured from waste methane that would otherwise have been emitted to the atmosphere. In practice, capturable waste methane is extremely limited and is more likely to be diverted from a flare than from direct atmospheric release in a climate-conscious policy context, which means that RNG systems need to be more destructively efficient than a flare to provide climate benefits versus the likely alternative management strategy. Assuming demand levels consistent with the goal of using existing FNG infrastructure, RNG is likely to be derived from methane that is either intentionally produced or diverted from a flare, so essentially any methane leakage is climate additional. Further, in a decarbonizing system, RNG will likely compete with lower-emissions resources than FNG and thus provides fewer net emissions benefits over time. Anticipated leakage is climatically significant: literature estimates for methane leakage from biogas production and upgrading facilities suggest that leakage is in the 2%–4% range (mass basis), up to as much as 15%. Policy makers should consider that under reasonable leakage and demand assumptions, RNG could be climate intensive.

1. Introduction

Climate change motivates an urgent global transition away from the use of fossil fuels for energy (Intergovernmental Panel on Climate Change 2014, Geels *et al* 2017, Mccauley and Heffron 2018, Davis *et al* 2018). Fossil fuels account for 85% of global commercial energy consumption (2018) (BP 2019) and dominate global energy infrastructure. Given the scale, costs, and economic implications of abandoning infrastructure before the end of its useful life, and given the challenge of transitioning energy systems quickly, there is substantial interest in the idea of renewable drop-in fuels (Rye *et al* 2010, Horvath 2016, Lynd 2017) that can use existing infrastructure without creating the

problems of fossil fuel use. This interest is particularly salient in the context of end uses that use specific fossil fuels directly. For example, transportation services currently rely primarily on refined oil, and many industrial and other heating applications directly burn natural gas. These direct users of fossil fuels are often unable to accommodate alternative fuels without abandoning functional infrastructure (e.g. internal combustion engine cars and natural gas-fired water heaters) in favor of infrastructure compatible with the new fuels (e.g. electric cars and electric water heaters).

This work assesses renewable natural gas (RNG) (Götz *et al* 2016, Gasper and Searchinger 2018), here referring both to biomethane (Parker *et al* 2017,

Paolini *et al* 2018) and power-to-gas (Götz *et al* 2016, Collet *et al* 2017), as a direct substitute for fossil natural gas (FNG). Drop-in substitutes for FNG specifically are valued due to the diversity of uses, and thus infrastructure, for FNG. In the United States (US), FNG accounts for about 30% of primary energy consumption (EIA 2018), split relatively evenly among power generation (~40%), industrial uses (~30%), and commercial and residential uses (~30%) (Energy Information Administration 2020). RNG has been proposed as a way to decarbonize this system while leveraging existing fossil infrastructure, including pipelines and end use equipment like home and industrial heating devices (Washington State University Energy Program 2018, Bataille 2019). This substitution is particularly relevant for non-electricity uses because they are often more difficult to decarbonize (Davis *et al* 2018, Bataille 2019), though RNG is also valued as an electricity fuel because RNG plants could provide fully dispatchable electricity generation that could reduce the need for costly electricity storage or demand management (Tarroja *et al* 2020). Similarly, like hydrogen, RNG manufacturing has been proposed as a sink for excess variable electricity that can be stored for later use, in the form of power-to-gas schemas (Götz *et al* 2016).

Like FNG, RNG is primarily methane (Gasper and Searchinger 2018), a potent greenhouse gas (GHG) (Intergovernmental Panel on Climate Change 2014) second only to carbon dioxide (CO₂) in its overall contribution to climate change (Weyant *et al* 2006). When RNG is produced from waste methane, converting it to CO₂ by burning it has climate benefits because of methane's much higher climate forcing potential (Intergovernmental Panel on Climate Change 2014) relative to CO₂. If the waste methane were going to be emitted to the atmosphere anyway, any system leakage (i.e. methane emissions) is a lost opportunity but not a climate stressor; otherwise, it contributes to climate change. This analysis shows that 1) RNG from intentionally produced methane, even from climate-neutral CO₂ sources, has substantial climate impacts at methane leakage levels observed in the existing, mature biogas industry (Pertl *et al* 2010, Flesch *et al* 2011, Whiting and Azapagic 2014, Ravina and Genon 2015, Hijazi *et al* 2016, Liebetau *et al* 2017, Paolini *et al* 2018, Vo *et al* 2018, Ramírez-Islas *et al* 2020); (2) for any meaningful system scale, RNG is likely to be derived from intentionally produced methane; and (3) even RNG from waste methane can have negative climate impacts relative to the most likely alternative of flaring, not venting, the methane when leakage from RNG production and use exceeds flaring loss rates.

2. Methods

This analysis evaluates the GHG intensity of RNG, focused on three methane feedstock pathways for

RNG production: (1) from waste methane that would have otherwise been emitted to the atmosphere; (2) from waste methane that would have otherwise been flared; and (3) from intentionally created methane that would otherwise not have existed. The carbon for RNG is assumed to be climate neutral, for example, biogenic or sourced from a carbon capture activity. Reported GHG intensities use IPCC's Fifth Assessment Report (AR5) 20- and 100-year GWPs with climate-carbon feedback, distinguishing between fossil and nonfossil methane GWPs (see Working Group 1, chapter 8, Tables 8.7 and 8.A.1). For comparison, the GHG intensity of FNG, generic resources with life cycle 2050 GHG intensity consistent with 2 °C warming (Pehl *et al* 2017), and zero carbon resources are also included. Full details and calculations are available in the Supplementary Data File.

The absolute GHG intensity of RNG is assumed to derive from methane leakage only (because combustion GHG emissions for RNG are climate neutral by assumption), drawing the system boundary at the point when the methane is diverted from the alternative management strategy (venting, flaring, or not existing) and excluding embodied GHGs in infrastructure or any of the production feedstocks. For example, power-to-gas pathways are implicitly assumed to use GHG-neutral power in facilities with zero embodied GHGs. GHG intensity is given as kilograms (kg) of carbon dioxide equivalent (CO₂e) per gigajoule (GJ) of methane consumed—that is, the denominator is the amount of methane that is ultimately delivered to the entity that combusts it, which is less than the amount of methane that is produced or withdrawn if system leakage exceeds 0%. Emissions associated with leakage are thus calculated as follows:

$$\begin{aligned} \text{absolute leakage – related GHG intensity} &= \\ &= \frac{\text{mass CH}_4 \text{ produced} \times \text{system leakage} \times \text{GWP}_{\text{CH}_4}}{(1 - \text{system leakage})} \times \text{system leakage} \times \text{GWP}_{\text{CH}_4} \end{aligned} \quad (1)$$

where system leakage is mass methane emitted/mass methane produced. Net emissions relative to the alternative fate for methane are calculated by subtracting the counterfactual methane emissions. For Path 1 (waste methane would have otherwise been emitted to the atmosphere), counterfactual emissions are that system leakage = 100%. For Path 2 (waste methane would have otherwise been flared), counterfactual emissions are that system leakage = (1-flare efficiency). For Path 3 (methane would not otherwise have existed), counterfactual emissions are 0. Thus, net emissions are given as:

$$\begin{aligned} \text{net leakage emissions} &= (\text{mass CH}_4 \text{ produced} \\ &\times \text{GWP}_{\text{CH}_4}) \times (\text{system leakage} - \text{counterfactual leakage}) \end{aligned} \quad (2)$$

For the three paths, Equation 2 becomes:

$$\text{Path 1, net leakage emissions} = (\text{mass CH}_4 \text{ produced} \times \text{GWP}_{\text{CH}_4}) \times (\text{system leakage} - 1) \quad (3)$$

$$\text{Path 2, net leakage emissions} = (\text{mass CH}_4 \text{ produced} \times \text{GWP}_{\text{CH}_4}) \times (\text{system leakage} - \text{flare leakage}) \quad (4)$$

$$\text{Path 3, net leakage emissions} = (\text{mass CH}_4 \text{ produced} \times \text{GWP}_{\text{CH}_4}) \times (\text{system leakage} - 0) \quad (5)$$

Note that because of the presentation of results per unit of methane combusted by a user and the fact that methane production = methane delivered/(1—system leakage) (equation (1)), equation (3) reduces to (mass CH₄ delivered × −GWP_{CH₄}) and is independent of leakage rate. For Path 2, emissions upstream of the flare are not considered because waste methane that is vented prior to diversion to the flare is not diverted to the flare, thus falling under Path 1.

Leakage from the RNG system is evaluated as a range because of substantial uncertainty about what leakage levels would be under future conditions, particularly if newer RNG pathways (e.g. power-to-gas) became widespread. This work considers the implications of RNG system leakage between 0%–15% mass leakage/mass produced in order to inform consideration of potential RNG futures. The range is most proximately based on Scheutz and Fredenslund's (2019) evaluation of 23 biogas plants, including seven facilities encompassing production through biogas upgrading to biomethane, where facility leakages from 0.4 to 14.9% of production were observed (see Supplementary Data File for details). Specific leakage sources are not always evident but might be correlated with plant complexity (e.g. number of units), maintenance regimes, and the status of biogas production as a core or non-core function (Scheutz and Fredenslund 2019). Published values in other studies and GHG protocols reflect ranges generally narrower than but consistent with Scheutz and Fredenslund's findings (Flesch *et al* 2011, Liebetrau *et al* 2013, 2017, Hrad *et al* 2015, Vo *et al* 2018, Bartoli *et al* 2019).

Leakage downstream of production and processing (i.e. during transportation, storage, and end use) is assumed to be identical for FNG and RNG. Although it is challenging to assign a value for these processes due to the diversity of end uses, lack of information about leakage during end uses, differential use of transmission, storage, and distribution by end users, and the dependence of transportation leakage on distance, a value of 0.8% (mass leaked per mass withdrawn or produced) was chosen in service of estimating absolute GHG intensities for comparison with zero-GHG systems. This value is based on assumptions and data from the literature (Liebetrau *et al* 2013, Lavoie *et al* 2017, Alvarez *et al*

2018) (see Supplementary Data File for details). For FNG, this value is added to an estimate of production and processing leakage of 2.1% mass leakage/mass withdrawn (Alvarez *et al* 2018), and for RNG, it is assumed to be included in the assessed 0%–15% range for full system potential leakage rates.

3. Results

3.1. GHG intensity of renewable natural gas

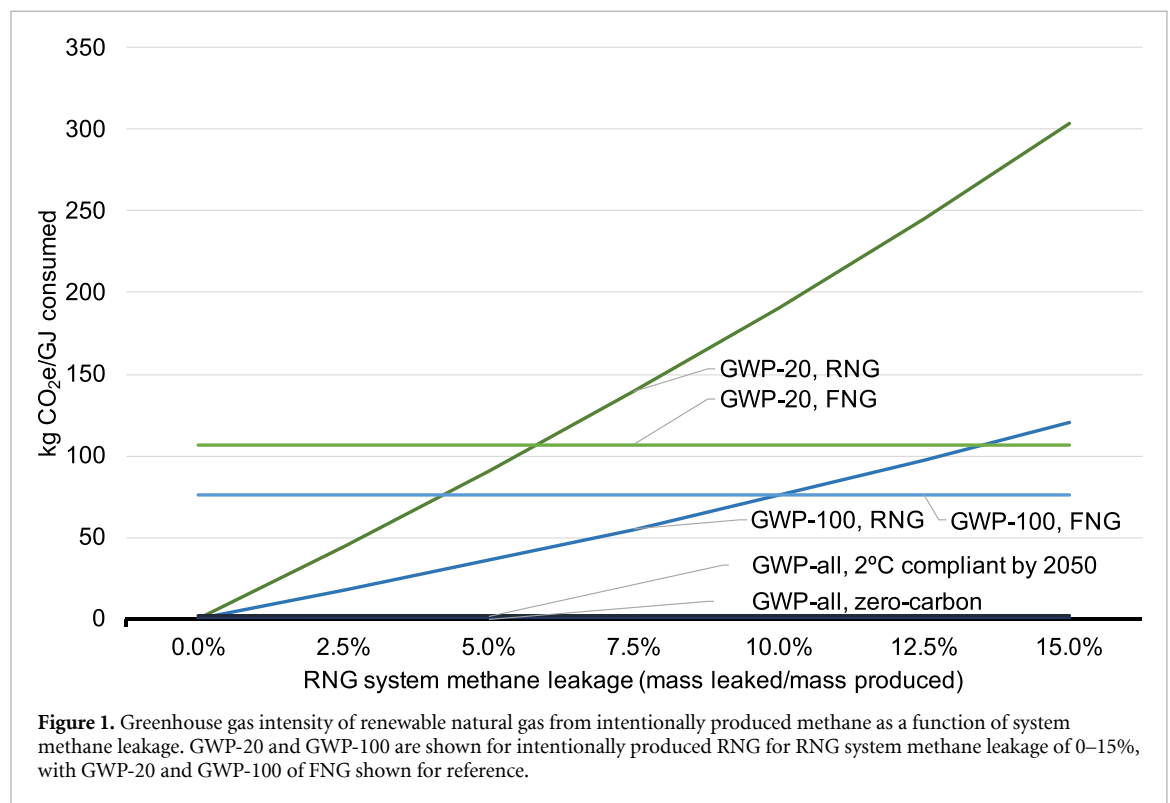
Table 1 shows the estimated GHG intensity of RNG for three production pathways as a function of system methane leakage: (1) RNG produced from waste methane that would have otherwise been emitted to the atmosphere (Path 1); (2) RNG produced from waste methane that would have otherwise been flared with 99% destructive efficiency (Path 2); and (3) RNG produced from intentionally created methane (Path 3).

In all cases, this analysis assumes that the CO₂ emitted from burning RNG is climate neutral for the RNG user, e.g. because it is sourced from biogenic or captured carbon that was taken up from and returned to the atmosphere over a period of time that is short from a climate perspective. Further, to emphasize the particular challenge posed by methane leakage, this analysis assumes RNG has no GHG intensity other than that associated with net impacts from methane leakage or destruction—that is, inputs to RNG production like electricity, hydrogen, and support infrastructure are assumed to be climate neutral. This assumption is consistent with the notion that zero-GHG electricity or hydrogen are potential alternatives to RNG. Note that because conversion processes are never 100% efficient, any GHG intensity for RNG associated with electricity or hydrogen inputs would exceed that of the electricity or hydrogen available for use.

As table 1 shows, the GHG intensity of RNG is driven by the counterfactual—that is, what would have otherwise happened to the source methane. Path 1, waste methane diversion from the atmosphere, is highly GHG negative because the counterfactual is that all utilized methane would have been emitted as methane. Leakage is irrelevant to GHG impact per unit of utilized methane because any leaks are methane that would have escaped anyway. Although Path 2 also uses waste methane, the counterfactual is that the waste methane would have been nonproductively burned in a flare, so RNG is GHG negative in this case only if the RNG system's total leakage is lower than leakage from the flare (1%), which is unlikely given that a best-guess estimate of downstream emissions alone is 0.8%. Path 3 uses intentionally produced methane. Here, the counterfactual is that no methane would have been released to the atmosphere, so any system leakage is GHG positive.

Table 1. Renewable natural gas carbon dioxide equivalent intensity by pathway, assuming climate-neutral combustion emissions of carbon dioxide.

| (a) GWP-100, kg CO ₂ e/GJ methane productively consumed | | | | | | | |
|---|-------|-------|-------|-------|-------|-------|-------|
| system leakage (mass CH ₄ emitted/mass CH ₄ produced) | 0 | 0.025 | 0.05 | 0.075 | 0.1 | 0.125 | 0.15 |
| Path 1: Waste methane diverted from emission to atmosphere | −680 | −680 | −680 | −680 | −680 | −680 | −680 |
| Path 2: Waste methane diverted from a 99% efficient flare | −7 | 10 | 29 | 48 | 68 | 89 | 112 |
| Path 3: Intentionally produced methane used | 0 | 17 | 36 | 55 | 76 | 97 | 120 |
| (b) GWP-20, kg CO ₂ e/GJ methane productively consumed | | | | | | | |
| system leakage (mass CH ₄ emitted/mass CH ₄ produced) | 0 | 0.025 | 0.05 | 0.075 | 0.1 | 0.125 | 0.15 |
| Path 1: Waste methane diverted from emission to atmosphere | −1720 | −1720 | −1720 | −1720 | −1720 | −1720 | −1720 |
| Path 2: Waste methane diverted from a 99% efficient flare | −17 | 26 | 72 | 121 | 172 | 226 | 283 |
| Path 3: Intentionally produced methane used | 0 | 44 | 91 | 139 | 191 | 246 | 304 |



3.2. Intentionally produced methane for RNG

A major finding of this analysis is that, as with FNG (Brandt *et al* 2014, Alvarez *et al* 2018, Grubert and Brandt 2019, Zhou *et al* 2019), RNG can have significant climate impacts associated with system methane leakage if the methane is intentionally produced (Path 3; table 1). Figure 1 shows the GHG intensity (kg CO₂e/GJ CH₄ productively consumed, e.g. for heat or electricity generation) of RNG from intentionally produced methane as a function of RNG system methane leakage.

As figure 1 shows, RNG from intentionally produced methane is always GHG positive unless total system leakage is 0. Given demonstrated transportation and end use leakage values on the order of 0.4–0.8% (Liebetau *et al* 2013, Lavoie *et al* 2017, Alvarez *et al* 2018), RNG from intentionally produced methane cannot outperform zero-GHG hydrogen or electricity systems on GHG intensity. Although

this analysis does not consider non-operational, non-methane GHGs, note that both hydrogen and electricity are likely inputs to intentionally produced methane for RNG, which therefore inherits and amplifies embodied emissions. The estimated methane-only GHG footprint of such RNG exceeds the combustion plus methane leakage GHG footprint of FNG when RNG system leakage is higher than about 10% (GWP-100) or 6% (GWP-20) on a mass leaked per mass produced basis. Accounting for IPCC stated uncertainty in the GWP of methane (Intergovernmental Panel on Climate Change 2014), the estimated leakage range within which RNG becomes more GHG intensive than FNG is about 9.1–11.1% (GWP-100) or 5.0–6.6% (GWP-20). Although power-to-gas systems and evaluations remain rare enough that data on leakage are not widely available (though leakage has been discussed (Vo *et al* 2018)), such leakage rates—particularly for a full system—are not uncommon

for biogas to RNG systems (Liebetrau *et al* 2013, 2017, Scheutz and Fredenslund 2019). For electricity, assuming the heat rate of a US natural gas combined cycle power plant and GWP-100, RNG's operational methane GHG intensity surpasses the 15 kg CO₂e/MWh total life cycle 2050 GHG intensity consistent with a 2 °C warming limit (Pehl *et al* 2017) for system leakage of 0.3%, which is less than some observed leakage from power plants alone (Lavoie *et al* 2017). Calculations can be found in the Supplementary Data File.

3.3. At scale, most methane feedstocks for RNG would likely be intentionally produced

How much RNG is likely to come from intentionally produced methane, which includes all power-to-gas RNG and RNG produced from feedstocks that would not degrade anaerobically (i.e. to methane rather than CO₂) absent intentional intervention (Meyer-Aurich *et al* 2012, Börjesson *et al* 2015, Agostini *et al* 2015)? The answer depends on assumptions about total demand and the availability of waste methane for diversion to RNG production. If the goal is to maintain the usefulness of FNG infrastructure, one potential assumption for RNG demand is that it would match current FNG demand. In 2017, US consumer consumption was 27.2 exajoules (EJ) of FNG, including 10.1 EJ for electric power and 8.7 EJ for often difficult-to-decarbonize industrial uses (see Supplementary Data File). The energy content of 2017 US uncontrolled methane emissions was about 1.6 EJ/year, about 0.3 EJ of which were emitted from biogenic sources (as opposed to, say, the FNG system) that could reasonably be captured (wastewater treatment plants and landfills, not enteric fermentation) (US EPA 2019, Grubert 2020), not all of which would become consumable RNG (i.e. due to parasitic energy requirements, conversion losses, etc). Thus, although some capturable waste methane (Paths 1 and 2) clearly exists, the degree to which RNG systems can depend on such resources at scale is low (<1%) relative to current natural gas demand.

One important observation for contextualizing these values is that not all methane from waste is waste methane. For example, the National Renewable Energy Laboratory (NREL) estimates that the energy content potential from methanogenic US wastes is about 5% the size of the US natural gas system (National Renewable Energy Laboratory 2013), including a methane potential estimate from wastewater (2.3 million tonnes/year) (National Renewable Energy Laboratory 2013) that is four times the US Greenhouse Gas Inventory (GHGI) estimate for methane emissions from wastewater treatment plants as of 2017 (0.57 million tonnes/year, Table 2–2) (US EPA 2019). Why? Unintentionally produced waste methane typically results from natural anaerobic digestion of wet organic wastes, like animal manure, sewage, and landfilled wastes, but this

digestion process does not completely convert carbon wastes to methane. Rather, digestion produces biogas, a blend of methane and CO₂ that can then be upgraded into near-pure biomethane, a form of RNG. Crucially, in part because biogas and biomethane can generate revenue, it is not only possible but expected to intervene in biological systems to increase methane production beyond what would have happened anyway when there is an incentive to do so (Hijazi *et al* 2016, Ferreira *et al* 2019, Garcia *et al* 2019). Thus, a single facility might produce both Path 1 (GHG-negative) and Path 3 (GHG-positive) methane from the same wastes.

Despite its limited availability, Path 1 methane is so GHG negative (table 1) that it is reasonable to investigate whether climate benefits can be retained if small amounts of very climate-negative RNG are blended with RNG from intentionally produced methane. Figure 2 shows GHG intensity of RNG for blends of 0%–100% Path 3 methane (intentionally produced) with Path 1 methane (waste methane diverted from release).

Figure 2 suggests that blending very GHG-negative RNG with GHG-positive RNG can enable a fairly large RNG system that is overall at least somewhat GHG-negative, assuming leakage levels within a typically observed range (see Supplementary Data File for detailed calculations and values). Assuming all 0.3 EJ of uncontrolled methane emissions from landfills and wastewater treatment plants could be captured and converted to consumer-ready RNG, either current industrial demand or electric power demand for FNG could be fulfilled by an RNG system with up to about 3% system leakage and theoretically remain GHG-negative (GWP-100; see Supplementary Data File). As the next section shows, however, such an outcome is unlikely because of the actual nature of waste methane management.

3.4. Capturable waste methane would be flared, not vented

The possible conclusion that sufficient highly GHG negative methane exists to support a large (e.g. FNG electricity system-sized) GHG negative RNG system is based on the assumption that waste methane is diverted from emission to the atmosphere (Path 1). This assumption is flawed if one also assumes that GHG emissions reductions are a policy priority, as existing practice is not the appropriate baseline for determining the counterfactual management practice for waste methane that could be available for RNG production (Haya *et al* 2019). Specifically, if the methane can be captured for RNG production, it can be captured for diversion to a flare, and it is unrealistic to assume that capturable methane would be vented under a GHG conscious policy regime. Even without federal climate regulation, the US regulates methane emissions from new landfills (US EPA 2016),

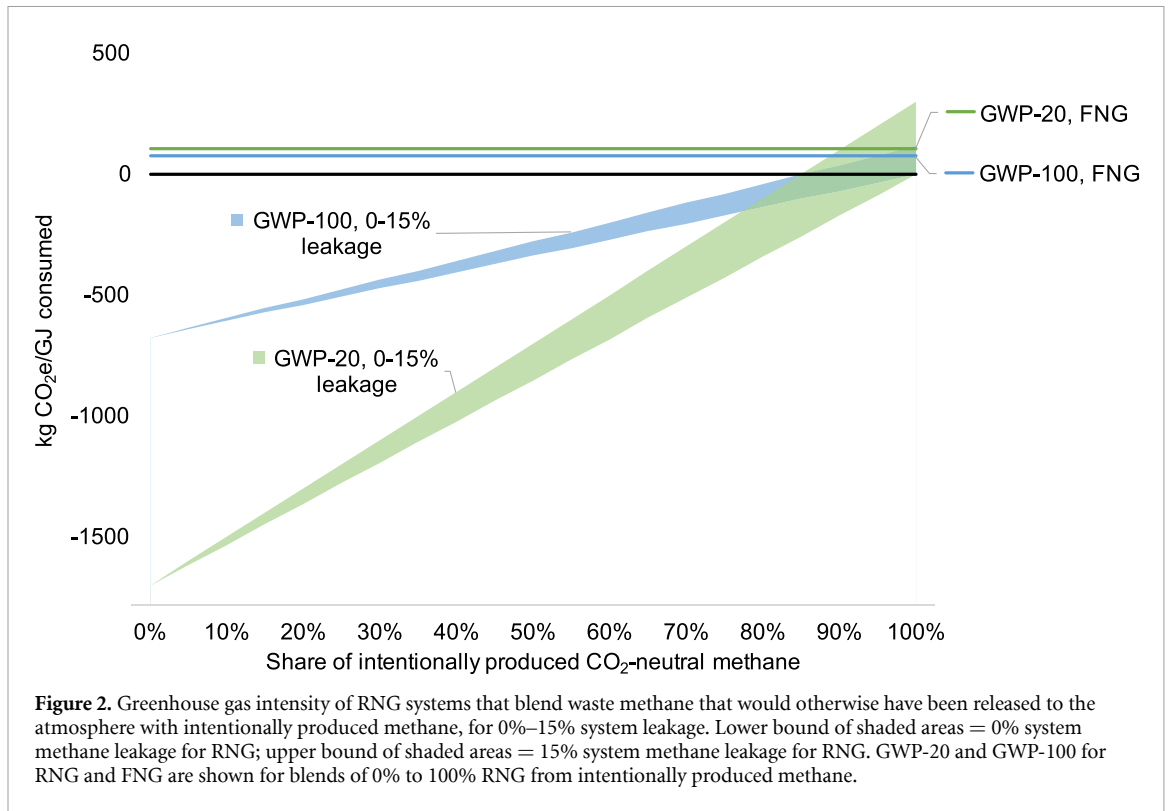


Figure 2. Greenhouse gas intensity of RNG systems that blend waste methane that would otherwise have been released to the atmosphere with intentionally produced methane, for 0%–15% system leakage. Lower bound of shaded areas = 0% system methane leakage for RNG; upper bound of shaded areas = 15% system methane leakage for RNG. GWP-20 and GWP-100 for RNG and FNG are shown for blends of 0% to 100% RNG from intentionally produced methane.

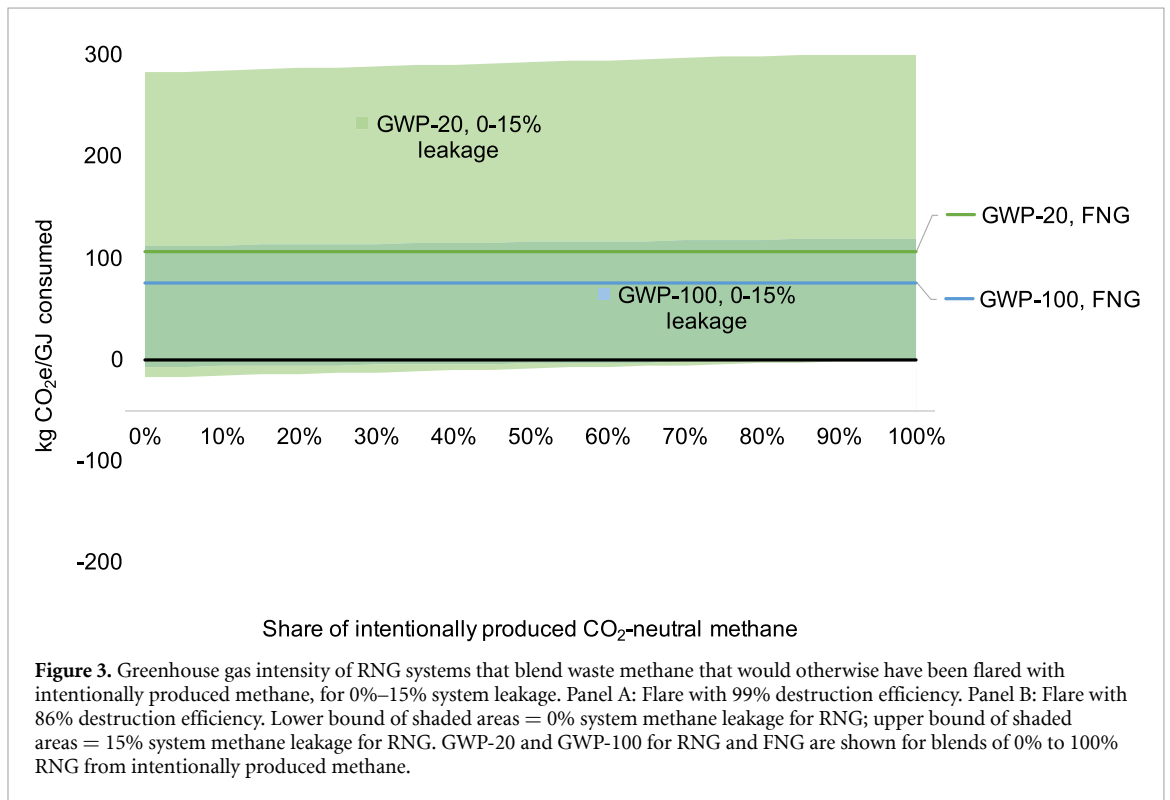


Figure 3. Greenhouse gas intensity of RNG systems that blend waste methane that would otherwise have been flared with intentionally produced methane, for 0%–15% system leakage. Panel A: Flare with 99% destruction efficiency. Panel B: Flare with 86% destruction efficiency. Lower bound of shaded areas = 0% system methane leakage for RNG; upper bound of shaded areas = 15% system methane leakage for RNG. GWP-20 and GWP-100 for RNG and FNG are shown for blends of 0% to 100% RNG from intentionally produced methane.

and many methanogenic facilities use methane capture with flares for safety reasons. Flaring destroys the methane with the same destructive benefit as combusting the methane productively. Figure 3 updates the assumptions used in figure 2 to show the same results, but assuming that RNG using Path 3 (intentionally produced) methane is blended with RNG using

Path 2 (waste diverted from flare) rather than Path 1 (waste diverted from release) methane. Figure 3 assumes 99% flare efficiency, described in the GHGI as a median value (US EPA 2019). Figure S1 (available at stacks.iop.org/ERL/15/084041/mmedia) shows results assuming the GHGI’s lower flare efficiency bound of 86 (US EPA 2019).

As figure 3 shows, conclusions about the viability of a large, GHG-negative RNG system change radically when the more realistic counterfactual of methane destruction rather than methane venting is applied. RNG system leakage would need to be essentially 0 (that is, lower than the flare's leakage) to be GHG-negative versus typical flare performance. Based on literature values for leakage, including the estimate of 0.8% leakage for processes downstream of production and processing, productive use of waste methane is unlikely to be more destructively efficient than a flare. Although waste methane being diverted for productive use arguably would not have been captured without the financial incentive of energy sales, given that capture infrastructure is not free, flaring is most likely the less GHG intensive alternative for waste methane once it has been captured. In a decarbonized energy system where RNG would be less likely to be replacing GHG-intensive fuels (and thus offsetting their emissions), and when a policy regime requiring or incentivizing destruction of GHG-intensive wastes might reasonably be expected to be in place, expected levels of methane leakage suggest that RNG is unlikely to be a low GHG energy resource relative to alternatives.

4. Discussion

RNG is not inherently climate friendly. Based on consideration of both the source of methane used to produce RNG and the likely alternative fate of that methane, and using reasonable assumptions about likely system methane leakage, it is unlikely that an RNG system could deliver GHG-negative, or even zero GHG, energy at scale. Substantial GHG benefits can be attained when waste methane is genuinely diverted from emission to the atmosphere, but the availability of such methane is low (Liu and Rajagopal 2019, US EPA 2019) relative to potential demand for climate friendly RNG, especially when considering that the alternative fate of capturable methane is more likely flaring than venting in a GHG-conscious setting. Under some system leakage rates that have been observed for biogas systems (Liebetau *et al* 2017, Scheutz and Fredenslund 2019), RNG might not even meet the less stringent threshold of outperforming FNG from a GHG perspective.

Designing a system that depends on RNG, or delaying transition to a system that does not depend on natural gas because of the promise of RNG, could delay climate mitigation because of induced demand for intentionally produced methane. Particularly given that past experience demonstrates that policy can rapidly drive resource allocation to RNG (Bartoli *et al* 2019), RNG's environmental performance should be carefully compared with that of its likely long-term competitors—not just FNG—before resources are allocated. Current literature on RNG often assumes the context of a fossil-based system

(see e.g. the reference systems for papers included in a review of LCA of biogas production (Hijazi *et al* 2016)), which leads to the crediting of lower environmental burden relative to this context (e.g. when RNG is given credit for avoided GHG impacts from FNG consumption (Scheutz and Fredenslund 2019, Ramirez-Islas *et al* 2020)). Such fossil-linked benefits disappear in a context where RNG could be substituting for zero-GHG alternatives like zero-GHG electricity or hydrogen rather than FNG, petroleum fuels, and GHG-intensive electricity.

Even beyond GHG emissions, environmental burdens associated with RNG that are acceptable relative to FNG merit deeper investigation when the alternative is, e.g. zero-GHG electricity. RNG is designed to be effectively indistinguishable from FNG at the point of use, so local combustion impacts are likely to be similar for clean RNG, and potentially worse for less pure RNG (Paolini *et al* 2018). Upstream of use, RNG would likely have different socioenvironmental impacts than FNG. Although RNG can use existing pipeline and user infrastructure, for example, it would obviate the need for FNG's production infrastructures, which have substantial socioenvironmental impacts (Jacquet *et al* 2018). RNG production facilities using primarily waste products (e.g. agricultural wastes, landfill gas, wastewater treatment gas, excess electricity generation) would likely not qualitatively change socioenvironmental impacts from those activities, though making certain practices financially viable could extend their life and extent (Haya *et al* 2019). Relatedly, having access to RNG could extend the life of existing fossil infrastructure, with mixed socioenvironmental outcomes.

To the extent that RNG facilitates lower impact energy systems, e.g. by avoiding the need for mineral (Sovacool *et al* 2020)- and cost-intensive electricity storage to help match supply and demand (Tarroja *et al* 2020), some of the marginal impacts of RNG could be offset by system benefits. These benefits are not guaranteed, however. As demonstrated by experience with renewable drop-in transportation fuels, the potential for drop-in renewable fuel use might not actually lead to renewable fuel use (Pouliot and Babcock 2017), and the renewable fuels themselves might have undesirable environmental characteristics (Liu and Rajagopal 2019). This work shows that RNG needs to be carefully evaluated in the context of expected long-run system conditions before it is adopted as a component of a zero GHG energy system, particularly given its potential for methane leakage-related climate pollution.

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Data Availability Statement

Any data that support the findings of this study are included within the article.

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ATTACHMENT 3
Sierra Club Response to Data Request
SoCalGas-Sierra Club-03

California Public Utilities Commission Docket No. A.25-10-008

Application of Southern California Gas Company (U 904 G) Proposing Woody Biomass Pilot Project

Sierra Club Response to Data Request SoCalGas-Sierra Club-03

To: Ismael Bautista, Jr., on behalf of SoCalGas
From: Nina Robertson, Earthjustice, on behalf of Sierra Club
Date Request Sent: March 25, 2026
Response Due: April 7, 2026

QUESTION 1:

In reference to the response to the question on page 19 of the Testimony of Dr. Ranajit Sahu, “What are your key findings and recommendations regarding the proposed Pilot Project?”:

QUESTION 1a:

As provided in Lucas/Summers Testimony, the proposed project site is at the Central California Almond Growers Association (CCAGA) facility located at 8325 S Madera Ave, Kerman, CA 93630, which is approximately 7 to 8 miles from the border of the populated areas of the City of Kerman. What is the distance assumed from the project site to the populated area of the City of Kerman?

RESPONSE 1a:

Sierra Club objects on the grounds this question is ambiguous and assumes facts not in evidence. “[P]opulated areas of the City of Kerman” and “populated area of the City of Kerman” are not defined in the question, SoCalGas Application, or Corrected Testimony. The record does not include information regarding miles between the facility and a “polluted area” or “populated areas.” The references to both “areas” and “area” are confusing and ambiguous.

Subject to and without waiving the foregoing objections, Sierra Club answers as follows:

Sierra Club’s Testimony did not assume any distances, as air pollutants disperse and have impacts over wide areas. As noted in Sierra Club’s Testimony at page 19 and pages 35 to 39, these air pollutants will disperse into areas that already have high levels of pollution per CalEnviroScreen. Even if one or more “population areas” is 7 to 8 miles from the facility, there

are potential still impacts to air quality from the Project. SoCalGas has not conducted any analysis of the impact of the Project's emissions on sensitive receptors or provided necessary information on where such sensitive receptors may be located. Further, sensitive receptors not located in the undefined "populated areas" may also exist.

QUESTION 1b:

Explain the correlation between the distance of the two locations when providing the key findings and recommendations.

RESPONSE 1b:

Sierra Club objects on the grounds this question is vague, ambiguous, calls for speculation, and assumes facts not in evidence. The question does not explain nor define "the two locations." The prior question references both populated "areas" and "area." The record does not contain information regarding any specific "location" except for the address of the CCAGA facility as noted in Question 1a. The question does not explain what is meant by the word "correlation." Further, Dr. Sahu's "key findings and recommendations" include numerous findings and recommendations.

Subject to and without waiving the foregoing objections, Sierra Club answers as follows:

As indicated in Sierra Club's Opening Testimony on pages 19 to 20, Dr. Sahu's findings and recommendations address air pollutants and impacts on environmental and social justice communities, air emissions study and reporting, and greenhouse gases. To the extent the "correlation between the distance of the two locations" refers to the distance between the "CCAGA facility" and some other defined location where a populated area is located, Dr. Sahu did not assume any distances, as noted in response to Question 1a, because air pollutants disperse over a wide area and will increase pollution in an already polluted region, as indicated in Dr. Sahu's Testimony.

QUESTION 1c:

Explain in general how the distance to the city population makes a difference in air quality impact evaluations particularly concerns raised about air toxics.

RESPONSE 1c:

Sierra Club objects on the grounds this question is ambiguous, calls for speculation, and assumes facts not in evidence. The question does not explain nor define "the city population." The

question does not explain what “air quality impact evaluations particularly concerns raised about air toxics” means.

Subject to and without waiving the foregoing objections, Sierra Club answers as follows:

Air pollutants, once emitted and then dispersed in the ambient air will reach receptors (i.e., exposed individuals) wherever they breathe in the ambient air. Ambient air is defined as any air outside the facility. *See, e.g.*, <https://www.baaqmd.gov/en/about-air-quality/glossary/glossary> (defining ambient air as “[o]utside air; any portion of the atmosphere not confined by walls and a roof.”) (last accessed Apr. 7, 2026). Air impact evaluations, including evaluations of the impact of air toxics emissions, assess emissions into ambient air. Proximity to sensitive receptors is also a factor in such evaluations.

QUESTION 2:

In reference to the question on page 24 of the Testimony of Dr. Ranajit Sahu, “In its March 3, 2026 Response 3-2d to Sierra Club’s February 18, 2026 data request, SoCalGas lists exhaust emissions to be monitored by the local air district as O₂ and NO_x, as well as ‘periodic third-party testing of all criteria pollutant emissions[.]’ In your assessment, is this statement an accurate listing of the likely emitted pollutants?”:

QUESTION 2a:

Explain in detail if air districts regulate and typically require measurement of CO₂ and N₂O.

RESPONSE 2a:

Sierra Club objects on the grounds this question is ambiguous, irrelevant and unlikely to lead to admissible evidence. The question asked of Dr. Sahu concerned likely emitted pollutants, not the pollutants monitored and regulated by air districts in California. “[R]egulate” is not defined in the question and can have many meanings.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

Typically, air districts require CO₂ but not N₂O to be measured. If greenhouse gases are “regulate[d]” by an air district, then these two greenhouse gases would be “regulate[d,]” but the scope, design, level, and effect of the regulation and any measurements can vary.

QUESTION 2b:

Please provide all relevant references that substantiate the claim that the proposed pilot will emit “a range of combustion air toxics such as benzene, toluene, xylenes, hexane, formaldehyde, and acetaldehyde, among others.” Would these species be expected to be captured within measurement of VOC's using the EPA methods typically required by air districts?

RESPONSE 2b:

Sierra Club objects on the grounds this question is ambiguous. “Captured within measurement of VOCs...” is confusing, vague and not defined.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

U.S. EPA's AP-42 Section 1.4 addresses emissions from the combustion of natural gas. Section 1.4.3 lists emissions from such combustion including volatile organic compounds ("VOCs"). Per federal regulation, VOCs include "any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions." *See* 40 CFR 51.100(s). Each of the compounds listed in Question 2b are VOCs. *See* U.S. EPA, "Volatile organic compounds," <https://cdxapps.epa.gov/oms-substance-registry-services/substance-details/761346> (listed under "Substance Relationships" tab) (last accessed Apr. 7, 2026).

These species are not separately quantified within the measurement of VOCs using the U.S. EPA methods typically required by air districts because the listed compounds are separate, individual, air toxics compounds, with a range of distinct, adverse health impacts. As a result, they are regulated separately from the regulation of VOCs as a whole. VOCs are regulated as a whole for their contribution to smog, and when VOCs are regulated as a whole, one indicator for VOCs is used, without speciation as to individual air toxics. Entirely separate regulations and thus test methods exist for individual air toxics that are VOCs. Those air toxics are regulated separately for their specific toxicity to humans.

QUESTION 2c:

Explain in detail if baseline/current disposal methods for biomass like air curtain burners, biomass plants, and diesel driven chipping and handling equipment are also expected to generate some amount of air toxics.

RESPONSE 2c:

Sierra Club objects on the grounds the question is vague and calls for speculation. The question does not explain the "disposal methods" in sufficient detail to determine "expected" air toxics.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows

The disposal methods presented in the Correct Testimony can emit air toxics, but the expected amount cannot be quantified because SoCalGas has not quantified these "baseline" air toxics or the air toxics from the Project. As noted in response to Question 2b, quantification of VOCs does not quantify emissions of individual air toxics.

QUESTION 3:

In reference to the question on page 25 of the Testimony of Dr. Ranajit Sahu, “Based on your knowledge, please explain the potential emissions from Lane 3, the bulk gas cleaning process.?”:

QUESTION 3a:

Please provide all citations to substantiate this claim that is relevant to the proposed pilot.

RESPONSE 3a:

Sierra Club objects on the grounds this question is ambiguous and vague, as it does not explain what is meant by “this claim[.]” No “claim” is referenced in the question.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

The summary of potential emissions from Lane 3 indicated in Dr. Sahu’s Testimony is based on Dr. Sahu’s evaluation of the project information regarding Lane 3 that was provided in SoCalGas’s Application, Corrected Testimony, and Data Request Responses. Based on that information, the Project will make use of a “flare.” Sierra Club indicated in testimony on pages 25 to 26 and 40 to 43 that flaring of syngas will emit a wide range of pollutants. As explained in response to Question 2b, combustion, which is used in a flare, emits a wide range of pollutants.

QUESTION 4:

In reference to the question on page 25 of the Testimony of Dr. Ranajit Sahu, “In its March 3, 2026 Response 3-2c to Sierra Club’s February 18, 2026 data request, SoCalGas states that this flare will be used ‘infrequently.’⁴⁰ Does this statement impact your conclusion that emissions from the flare are likely?”:

QUESTION 4a:

Please provide details of the projects that the expert was involved in where flaring was considerable. Explain in detail the expert, Dr. Ranajit Sahu, level of involvement in these projects.

RESPONSE 4a:

Sierra Club objects on the grounds this question is ambiguous, as the term “considerable” is not defined.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

Dr. Sahu has reviewed a wide range of projects involving flaring including numerous plants that use thermal (or catalytic) oxidizers for pollution destruction such as ethylene oxide sterilizers owned by Sterigenics, B. Braun, and Becton Dickinson. Dr. Sahu has also evaluated storage terminals that store petroleum products and derivatives and thermal oxidizers that are used to control tank emissions like degassing.

QUESTION 4b:

Explain in detail the correlation between these projects and the one involved in this proceeding.

RESPONSE 4b:

Sierra Club objects on the grounds this question is ambiguous, as the term “correlation” has many meanings and is not defined.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

To the extent the question seeks information on similarities between the projects previously studied by Dr. Sahu and the proposed Project, all propose the use of thermal oxidizers for the flaring of gas. Dr. Sahu indicated in testimony at page 40 that emissions from the thermal oxidizer (or flare) can be directly measured at the stack using continuous monitoring systems for NO_x, PM_{2.5} (filterable), CO, and other emissions and also by conducting periodic, representative, stack testing for other pollutants including air toxics.

QUESTION 5:

In reference to the question on page 26 of the Testimony of Dr. Ranajit Sahu, “SoCalGas states in its February 23, 2026 Response 2-14a to Sierra Club’s February 9, 2026 data request that the flare will only be used 0.5% of the hours.⁴² It also states in its March 11, 2026 Response 5-9f to Sierra Club’s February 25, 2026 data request that ‘WBF estimates the flare will be used for a maximum of 10 minutes for an initial startup or emergency shutdown of the methanation system. In the first year, which includes commissioning, WBF anticipates up to 120 startups and shutdowns which is the basis for less than 0.5% of hours. After the facility is commissioned, WBF only anticipates approximately 8 to 10 startups/shutdowns annually.’⁴³ Do these responses address your concerns with flare emissions? If not, why not?⁴⁰ Does this statement impact your conclusion that emissions from the flare are likely?”:

RESPONSE 5:

QUESTION 5a:

Please provide citations and quantitative calculations supporting the claim that the flare will release “a substantial amount of health-harming emissions”.

RESPONSE 5a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 25. Further, the question “Does this statement impact your conclusion that emissions from the flare are likely?” is asked in a separate question in Sierra Club’s Testimony on page 25.

Anytime there is flaring, emissions are inevitable, and those emissions are harmful to human health, as noted above in Response 2b. Emissions depend not only on the duration of the flaring but also the amount of gas flared. Since the information provided by SoCalGas only provides, at best, the possible durations of the flaring events, nothing is disclosed or known to the public about the amount of gases that will be flared. As Dr. Sahu explained in testimony at pages 25 and 26, it is his expert opinion that emissions will be substantial because:

 this is a pilot project where experimentation with the process, especially the methanation step, will occur regularly. Indeed, based on the information I have reviewed and based on my experience reviewing West Biofuels’s project at Woodland proposed by Pacific Gas & Electric Company (“PG&E”) in A.23-06-023, West Biofuels does not have much experience with syngas generation or methanation. The associated experimentation

necessarily entails many stops and starts and generation of syngas that is off-spec and must therefore be flared. Similarly, there will be substantial experimentation in the methanation lane of the proposed Project. Second, the scale of the proposed Project is substantial and much larger than any gasification and methanation project that West Biofuels has operated before. This large size means that a lot of syngas will be produced that may be off-spec and that needs to be flared. So, based on how much as well as how often the flare will be used in this experimental proposed Project, the emissions from flaring will be considerable.

QUESTION 6:

In reference to the question on page 25 of the Testimony of Dr. Ranajit Sahu, “In its March 3, 2026 Response 3-2e to Sierra Club’s February 18, 2026 data request, SoCalGas lists the composition of the gas that would be flared. Does this information indicate what the flare emissions will be?”:

QUESTION 6a:

Explain in detail if thermal oxidizers/enclosed flares are mature technology used by industry for safety and environmental protection.

RESPONSE 6a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 26.

They are mature technology, but this fact does not mean that they do not have substantial emissions of criteria pollutants, air toxics, or greenhouse gases.

QUESTION 6b:

Explain in detail if the manufacturer of a thermal oxidizer/enclosed flare would be expected to be able to model and estimate the destruction efficiency of the various gases in the syngas and guarantee the emissions performance from their product.

RESPONSE 6b:

This modeling is typically not done by manufacturers for each individual VOC and air toxic compound in the inlet to the flare. The waste gas composition generally does not show each individual VOC or air toxic. In addition, the flare will produce air toxics as a result of the combustion process that are not present in the inlet waste gas. For these compounds, the destruction efficiency (i.e., (outlet mass – inlet mass)/outlet mass) will be negative since the flare will be a net producer (not destructor) of these combustion-generated air toxics that are not present in the inlet waste gas.

QUESTION 7:

In reference to the question on page 27 of the Testimony of Dr. Ranajit Sahu, “Why, in your opinion, will there be fugitive emissions in Lane 4?”:

QUESTION 7a:

Explain in detail the role monitoring and implementation of an EPA leak detection and repair (LDAR) program would play in minimizing fugitive emissions.

RESPONSE 7a:

Sierra Club objects on the grounds this question is ambiguous, calls for speculation, and assumes facts not in evidence.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

Sierra Club does not know what role LDAR will play in the proposed Project’s monitoring and implementation of LDAR beyond what is stated by SoCalGas in the Application, Corrected Testimony, and Data Request Responses. As explained Dr. Sahu’s Testimony at pages 26 and 27, because the information provided by SoCalGas shows that there will be piping in Lane 4, there will be fugitive emissions from piping components, and there is no evidence that LDAR or any other methods or protocols proposed by SoCalGas will detect all levels of fugitive emissions.

QUESTION 7b:

Explain in detail if a well-developed LDAR program using EPA Method 21 detection equipment would be expected to minimize fugitive emissions as well as leaks.

RESPONSE 7b:

Sierra Club objects on the grounds this question is ambiguous and calls for speculation, as the term “well-developed” is not defined, is subjective, and can therefore have many meanings.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

As indicated in Sierra Club’s Testimony at pages 28 and 29, the record does not show that the proposed Project’s fugitive emissions will be minimized because the equipment and methods that the proposed Project intends to use (per SoCalGas Application, Testimony and responses to Data Requests) are intended to detect leaks that pose safety risks at higher concentrations, and not all fugitive emissions, which will be emitted at much lower concentrations.

QUESTION 7c:

Explain if a well-developed LDAR program generating Method 21 screening values for facility equipment can be used to generate a correlative fugitive emissions estimate for the facility.

RESPONSE 7c:

Sierra Club objects on the grounds this question is ambiguous and calls for speculation, as the term “well-developed” is not defined, is subjective, and can have many meanings.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

No, it cannot be used to generate a correlative fugitive emissions estimate for the facility because generating correlations of Method 21 screening measurements to fugitive mass emissions requires that the total amounts of fugitive emissions first has to be captured. That capture is not part of Method 21. Therefore no correlations can be developed just from Method 21 concentration measurements. Further Method 21 applies to VOCs, not methane.

QUESTION 8:

In reference to the question on page 28 of the Testimony of Dr. Ranajit Sahu, “What is the GHG impact of CO2 venting?”:

QUESTION 8a:

Explain in detail if a large fraction (or all) of the CO2 from the biomass is also released back to the atmosphere in the baseline cases.

RESPONSE 8a:

Sierra Club objects on the grounds this question is ambiguous and calls for speculation. The term “large fraction” is not defined and can have many meanings.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

The baseline cases presented in Application and Corrected Testimony do not indicate the “fraction . . . of the CO2” from the biomass that is released back into the atmosphere. Further, as the Testimony of Dr. Emily Grubert indicates at pages 7-10, the CO2 impact from the baseline cases is not correctly evaluated in the Application and Corrected Testimony.

QUESTION 9:

In reference to the question on page 31 of the Testimony of Dr. Ranajit Sahu, “Without such measurement and reporting, do you think SoCalGas can credibly claim that it has demonstrated GHG reductions in this Application?”:

QUESTION 9a:

Please all provide a reference and quantitative calculations supporting the claim of “they will not be zero and could be substantial.”

RESPONSE 9a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 30.

The question’s reference to “such measurement” refers to fugitive methane leakage measurement and reporting as indicated on page 30 of Sierra Club’s Testimony. As stated in the Testimony of Dr. Sahu, the assumption by SoCalGas that such emissions will be “negligible” is not supported by the evidence in the record given the risk of fugitive leaks and the inability to detect and prevent them. Therefore, as Sierra Club’s Testimony indicates, it is the expert opinion of Dr. Sahu that such emissions will not be zero and could be substantial (i.e., not negligible). The Testimony of Dr. Grubert further supports this conclusion at pages 11 and 12, and even if methane leakage were assumed to be zero (which is an unrealistic and unsupported assumption), the corrected Whole Orchard Recycling biogenicity assumption alone indicates that the base case has lower greenhouse gas emissions than the use cases both with and without CCS, such that Project emissions will not be zero and could be substantial.

QUESTION 10:

In reference to the question on page 31 of Dr. Ranajit Sahu, “In its February 26, 2026 Response 4 to Cal Advocates’ February 11, 2026 data request, SoCalGas indicates that ‘WBF employs regular scheduled inspections using advanced methane detection technologies, such as handheld detectors, optical gas imaging cameras, and continuous monitoring systems within confined areas and buildings. Inspections are conducted at key points, including production equipment, pipeline connections, and transfer points.’⁵⁶ In your opinion, is this methane leak detection sufficient to ensure no fugitive methane leakage occurs.?”:

QUESTION 10a:

Explain if EPA allows handheld detectors that are compliant with Method 21 to be used in LDAR programs. Explain if these detectors are expected to be able to detect fugitive leaks, particularly if they can detect down to tens of ppm levels.

RESPONSE 10a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 30.

Sierra Club objects on the grounds this question assumes facts not in evidence. SoCalGas did not present anything regarding use of Method 21 in the Application, Corrected Testimony, or Data Request Responses.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

U.S. EPA allows handheld detectors that are compliant with Method 21 to be used in LDAR programs that address VOCs. Whether these detectors will detect fugitive leaks of VOCs depends on how they are used and how trained the operators are, and this information is not in the record. Notably, EPA’s use of Method 21 to assess VOC leaks does not address methane leaks (since methane is not a VOC), which are a primary concern raised by Sierra Club’s testimony.

QUESTION 10b:

40 CFR Part 60, Appendix K requires optical gas imaging (OGI) cameras to detect methane leaks of down to 19 g/hr under specific conditions. Would it be prudent for a facility that is trying to screen for and prevent leaks and also minimize fugitive emissions to employ a hybrid program that utilizes both OGI and Method 21 detectors?

RESPONSE 10b:

Sierra Club objects on the grounds this question assumes facts not in evidence, requires speculation, and is ambiguous and vague. SoCalGas did not propose any part of the Project comply with 40 CFR Part 60, Appendix K requirements in the Application, Corrected Testimony, or Data Request Responses. “[H]ybrid program” is ambiguous and not defined. SoCalGas has not presented any program in the record. Also, “prudent” is ambiguous and subjective.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

A monitoring program that includes these methods could detect certain levels of leaks and fugitive emissions, but additional factors are relevant as indicated above in response to Question 10a, and SoCalGas has not proposed such a protocol for review in its Project materials. Furthermore, even if leaks and fugitives are detectable, there will still be some emissions of methane such that the assumption of zero methane leakage is unrealistic and unsupported.

QUESTION 11:

In reference to the question on page 33 of the Testimony of Dr. Ranajit Sahu, ‘To summarize, in your opinion, what pollutants will be emitted from the proposed pilot project?’:

QUESTION 11a:

Did SoCalGas provide estimates of volatile organic compounds (VOC)?

RESPONSE 11a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 32.

SoCalGas provided estimates of the emissions factor for VOCs in its Corrected Testimony but did not provide estimates of daily and annual VOC emissions from the proposed Project. Further, SoCalGas did not provide estimates of Project emissions of individual air toxics (which, as noted above in response to Question 2b, are VOCs) such as benzene, toluene, xylenes, hexane, formaldehyde, various polycyclic aromatic compounds, and numerous metals.

QUESTION 11b:

If air toxics do exist, would they be expected to be quantified within the measurement of VOC?

RESPONSE 11b:

No, air toxics cannot be “expected to be quantified within” the measurement of VOCs. See response to Question 2b above.

QUESTION 12:

In reference to the response to the question, “[W]here the gasification facility would be located,” Dr. Ranajit Sahu responded on page 35 that “the proposed facility would be located in Kerman, California.”

QUESTION 12a:

As provided in Lucas/Summers Testimony, the proposed project site is at the Central California Almond Growers Association (CCAGA) facility located at 8325 S Madera Ave, Kerman, CA 93630, which is approximately 7 to 8 miles from the border of the populated areas of the City of Kerman. What relevance does distance make in terms of the claimed air pollution impacts on the population of Kerman, CA?

RESPONSE 12a:

See responses to Question 1.

QUESTION 13:

In reference to the response to the question, “In your opinion, will the proposed project improve the air quality in and around Kerman, CA?,” Dr. Ranajit Sahu stated on page 38, “No. As explained above, I believe and the Application admits that the proposed facility will cause additional pollution. That pollution will worsen air quality in the region.”

QUESTION 13a:

Does this opinion factor in the regional emissions from the baseline practices that would be displaced? If not, explain in detail why not.

RESPONSE 13a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 37.

There is no evidence that a one-to-one “displace[ment]” of these emissions will occur. Air impacts of both baseline and Project emissions must be separately assessed since each will affect the ambient air differently, both spatially and temporally. Based on the record in this proceeding, SoCalGas has not conducted such an assessment. Further, SoCalGas has not provided sufficient information regarding the basis for baseline emissions factor assumptions, such that their accuracy can be evaluated. As noted in response to Question 2b and 11b, SoCalGas has not quantified the emissions of individual air toxics. Finally, even based on a comparison on SoCalGas’s base case assumption and Project use case assumptions as presented in Corrected Testimony at JLMS 15 and 16, the emissions factor for VOCs increases from 1.53 mg/MJ in the base case to 2.04 and 2.88 mg/MJ in the use cases without and with carbon capture and storage, respectively. Also, the emissions factor for NO_x increases in the use case with carbon capture and storage from 19.69 mg/MJ to 24.86 mg/MJ.

QUESTION 14:

In reference to the question on page 38 of the Testimony of Dr Ranajit Sahu, “Will the project bring the region closer to attainment for PM2.5 and Ozone under the Clean Air Act?”:

QUESTION 14a:

In terms of “Attainment,” are emissions ever evaluated on a project-by-project basis or is it a characterization of the total emissions for the region as a whole?

RESPONSE 14a:

Sierra Club notes that the page number cited in the question is incorrect. The correct page number is 37.

Sierra Club objects on the grounds this question is ambiguous and calls for speculation. “[E]ver evaluated” can have many meanings, and the question does not specify the evaluator.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

To the extent the question asks whether air regulators evaluate air quality regionally and air quality impacts on a project-by-project basis, the answer is that both are conducted. Further, the regional analysis includes emissions inventories of permitted projects.

QUESTION 14b:

Is the “Attainment Plan” implemented by the San Joaquin Valley Air Pollution Control District the tool that ensures that criteria pollutant emissions are reduced for the region?

RESPONSE 14b:

Sierra Club objects on the grounds this question is ambiguous and calls for speculation. “[T]he tool” is not defined and can have many meanings. The “Attainment Plan” is not defined. Multiple “attainment plans” are applicable.

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

No. Each air district has multiple attainment plans, and these plans are not enforcement documents that can “ensure” reductions by themselves.

QUESTION 14c:

Do all projects reviewed for air permits by the San Joaquin Valley Air Pollution Control District have to follow their Attainment Plan, which typically requires offsets or improvements that reduce regional pollution while enabling development?

RESPONSE 14c:

Sierra Club objects on the grounds this question is ambiguous, calls for speculation, and assumes facts not in evidence. “[R]eview[.]” is not defined and can have many meanings. The “Attainment Plan” is not defined. Multiple attainment plans are applicable. The record does not contain evidence that the applicable attainment plans “typically require[.] offsets or improvements that reduce regional pollution while enabling development[.]”

Subject to and without waiving the foregoing objection, Sierra Club answers as follows:

Sierra Club cannot speak to what “review[.]” will be conducted, how thoroughly this Project will be evaluated by the San Joaquin Valley Air Pollution Control District, or what if any offsets or improvement will be required as a result of the proposed Project.