

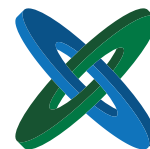
Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications

An Independent Review of Scientific and Technical Information



FULL REPORT

A Commissioned Report prepared by the
California Council on Science and Technology



CCST
CALIFORNIA COUNCIL ON
SCIENCE & TECHNOLOGY

A nonpartisan, nonprofit organization established via the California State Legislature
— making California's policies stronger with science since 1988

Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications

An Independent Review of Scientific
and Technical Information

Full Report

Gregory Von Wald, Stanford University

Adam Brandt, PhD, Stanford University (Ex Officio, Non-Voting SC Member)

Deepak Rajagopal, PhD, University of California Los Angeles

Austin Stanion, University of California Los Angeles

*James L. Sweeney, PhD, Stanford University and CCST Council Chair
Steering Committee Chair*

*Amber J. Mace, PhD, California Council on Science and Technology
Project Director*

*Sarah E. Brady, PhD, California Council on Science and Technology
Project Manager*

Steering Committee Members

Charles Benson, etaPartners LLC

Fokion Egolfopolous, PhD, University of Southern California

Charles D. Kolstad, PhD, Stanford University

Diane Saber, PhD, Reethink

Jessica Westbrook, PhD, Sandia National Laboratories

June 2018

Acknowledgments

This report has been prepared by the California Council on Science and Technology (CCST) with funding from the California Public Utilities Commission.

Copyright

Copyright 2018 by the California Council on Science and Technology

ISBN Number: 978-1-930117-59-4

Biomethane in California Common Carrier Pipelines:

Assessing Heating Value and Maximum Siloxane Specifications

About CCST

The California Council on Science and Technology is a nonpartisan, nonprofit organization established via the California State Legislature in 1988. CCST responds to the Governor, the Legislature, and other State entities who request independent assessment of public policy issues affecting the State of California relating to science and technology. CCST engages leading experts in science and technology to advise state policymakers — ensuring that California policy is strengthened and informed by scientific knowledge, research, and innovation.

Note

The California Council on Science and Technology (CCST) has made every reasonable effort to assure the accuracy of the information in this publication. However, the contents of this publication are subject to changes, omissions, and errors, and CCST does not accept responsibility for any inaccuracies that may occur.

For questions or comments on this publication contact:

California Council on Science and Technology

1130 K Street, Suite 280 Sacramento, CA 95814

916-492-0996

ccst@ccst.us www.ccst.us

Layout by A Graphic Advantage!

3901 Carter Street #2, Riverside, CA 92501

www.agraphicadvantage.com

Table of Contents

Chapter 1: Scope of work	1
Chapter 2: Natural gas and biomethane: Similarities and differences	3
2.1 Sources of natural gas and biogas.....	3
2.2 Composition of natural gas and biogas	4
2.3 Differences in energy content between natural gas and biogas.....	5
2.4 Presence of trace constituents in biogas and natural gas	8
2.5 Processing of natural gas and biogas	10
Chapter 3: Regulation of natural gas quality for safety and system integrity	13
3.1 The need for gas quality regulation	13
3.2 Regulation of gas heating value.....	14
3.3 Regulation of gas interchangeability.....	16
3.4 Regulation of gas siloxane content	18
3.5 Current California regulations of gas quality	20
3.6 California regulatory history	21
3.6.1 California minimum HV specification.....	21
3.6.2 California maximum siloxane specification.....	23
Chapter 4: Assessment of evidence for the current California heating value specification	25
4.1 Experimental literature on HV and interchangeability	25
4.2 Review of data on California appliances and equipment in place	29
4.3 Review of historical heating value delivered in California.....	30

Table of Contents

4.4 Quantitative assessment of three representative HV specifications.....	32
4.4.1 Impact on required gas purity.....	33
4.4.2 Interaction with existing equipment base	34
4.4.3 Interaction with other intersecting gas quality specifications	34
4.5 Summary of upgrading methods	39
4.5.1 Removal of inert components	39
4.5.2 Addition of higher HV components	40
4.6 Synthesizing conclusions and recommendations	40
Chapter 5: Assessment of evidence for the current California siloxane specification	43
5.1 Empirical experiments of impacts of siloxanes on combustion appliances	44
5.2 Scientific literature on depositional modeling.....	45
5.3 Review of operational experiences	46
5.4 Review of combustion equipment manufacturer specifications	48
5.5 Review of siloxane presence and removal from biomethane	50
5.6 Review of potential human health impacts of siloxanes	52
5.7 Review of methods of measuring siloxanes.....	54
5.8 Synthesizing conclusions and recommendations	57
Chapter 6: Implications of gas quality specifications for cost and value of biomethane in California	61
6.1 Cost implications of HV specifications	61
6.1.1 Survey of equipment vendors for cost of upgrading biogas to 970 Btu/scf and 990 Btu/scf.....	61
6.1.2 Estimating the Levelized Cost of Upgrading Biogas (LCUG) based on vendor data	66

Table of Contents

6.1.3 Economics of blending propane for meeting HV specification.....	69
6.1.4 Sensitivity to discount rate and capacity factor.....	69
6.1.5 Comparison to prior studies that estimate upgrading costs	70
6.2 Review of cost implications of siloxane specifications	71
6.3 Regulatory incentives affecting the economics of pipeline injection of biomethane	73
6.3.1 Biomethane under the RFS.....	73
6.3.2 Biomethane under the California LCFS.....	75
6.4 Economics of alternatives to pipeline transportation	76
Chapter 7: Options for dilution of biomethane	83
Chapter 8: Simulation and analysis of regional gas pipeline networks	89
8.1 Review of gas network simulation literature	89
8.2 Regional gas pipeline network simulation case studies	90
8.2.1 San Diego.....	92
8.2.2 Hanford.....	93
8.2.3 San Francisco / South Bay Area	94
8.3 Synthesizing conclusions	95
Works Cited	96
Appendix A: Gaseous fuel interchangeability literature.....	101
Appendix B: Empirical studies of siloxane combustion.....	105
Appendix C: Technical summary of siloxane removal technologies	109
Appendix D: Technical summary of HV upgrading methods.....	111

Appendix E: Supporting information for economic analysis.....	115
E1. Companies contacted and location.....	115
E2. Data request document	116
E3. Manufacturer Concerns.....	118
Appendix F: Supporting data tables for gas grid simulation.....	119
Appendix G: Study Charge.....	123
Appendix H: Statement of Work	127
Appendix I: CCST Steering Committee Members	133
Appendix J: Science Team Report Author Biosketches	139
Appendix K: Glossary.....	145
Appendix L: Review of Information Sources	149
Appendix M: California Council on Science and Technology Study Process	151
Appendix N: Expert Oversight and Review	155
Appendix O: Full List of Findings, Conclusions, and Recommendations.....	157
Appendix P: Acknowledgements	161

List of Figures

Figure 1. Reported minimum HV specifications from tariffs surveyed in AGA 2009 survey of North American gas systems.....	15
Figure 2. Conceptual map of interchangeability impacts as a function of Wobbe Number (vertical axis) and heating value (HV, horizontal axis).	18
Figure 3. Statewide residential natural gas consumption by use.	29
Figure 4. California statewide industrial natural gas consumption by sector.	30
Figure 5. Historical monthly average HV of natural gas delivered in California.	31
Figure 6. Historical HVs in PG&E BTU districts during the period November 2007 to November 2017 (Left). Distribution of HV in SoCalGas service territory during the period June 2012 to March 2017.....	32
Figure 7. Heating value of biogas mixtures as a function of the percent of CH ₄ in a mixture of CH ₄ and CO ₂	33
Figure 8. The regulatory constraints on acceptable biomethane composition are visualized as prescribed by Rule 30 (left) and Rule 21 (right).....	37
Figure 9. Distribution of reported maximum CO ₂ specification across 224 publicly available tariffs from U.S. and Canada.....	38
Figure 10. Illustration of silica deposition density as a function of concentration.	46
Figure 11. Survey of siloxane specifications reported by manufacturers of combustion equipment.....	50
Figure 12. Presence of siloxanes in raw biogas and biomethane derived from three major sources. Concentration is per species, not total Si.	52
Figure 13. Distribution of vendor estimates of upfront capital cost which includes both equipment and installation cost.....	63
Figure 14. Distribution of vendor estimates of monthly operating capital cost of upgrading and cleanup equipment.	64

List of Figures

Figure 15. Levelized cost (in \$/MMBTU) of upgrading gas (LCUG) to pipeline standards assuming a 12% discount rate and capacity factor of 80%.	68
Figure 16. Cost of siloxane removal in \$/MMBTU as a function of scale.....	72
Figure 17. The effect of injection volume on gas dilution.....	86
Figure 18. Two methods of mixing biomethane with NG.	86
Figure 19. San Diego regional gas network flows evaluated for January, April, July, and October 2016.	93
Figure 20. Hanford regional gas network flows evaluated for June and December 2016..	94
Figure 21. Bay Area regional gas network flows evaluated for January, April, July, and October 2016.	95

List of Tables

Table 1. Theoretical biogas yield and composition by organic matter constituent.....	4
Table 2. Raw, pre-processing biogas composition for various sources of biogas.....	5
Table 3. Molecular weights and heating value per standard cubic foot of associated gaseous compounds present in natural gas and/or biogas.....	6
Table 4. Chemical characteristics and unit conversions of siloxane compounds.	8
Table 5. International siloxane specifications for grid injection of biomethane.	19
Table 6. Interchangeability studies from empirical literature (n.d. = no data).	27
Table 7. Representative baseline gas compositions for Rule 21 and Rule 30 historical median gas quality.	36
Table 8. Summary of experimental literature regarding siloxane fouling of combustion appliances.....	44
Table 9. Number of active biomethane projects from landfills and wastewater treatment plants in the U.S.....	47
Table 10. Surveys of maximum siloxane concentration in end-use equipment.	49
Table 11. Representative gas compositions given to vendors of upgrading system for cost estimation.	62
Table 12. Table of cost estimates received from vendors.	65
Table 13. Estimates of LCUG (\$/MMBTU) for a discount rate of 12% and a capacity factor of 80%.	68
Table 14. Sensitivity of LCUG (\$/MMBTU) to discount rate and capacity factor.....	70
Table 15. Cost of upgrading from various literature surveys.	71
Table 16. Carbon intensity (CI) ratings (gCO ₂ e/MJ) for currently certified pathways for renewable CNG derived from different feedstocks and delivered via pipelines.	75

List of Tables

Table 17. Illustrative calculation of economics of conversion of biogas to electricity for grid supply.	78
Table 18. From Section 6.3, upgrading biogas to biomethane for pipeline injection entails the following cost and revenue streams.	78
Table 19. From Section 6.4, conversion of biogas to electricity entails the following cost and revenue streams.	79
Table 20. 2011 Industrial gas by sector in California	104
Table 21. Data request table provided to biomethane upgrading equipment suppliers...	117
Table 22. HV delivered by zip code for the San Diego regional case study.	119
Table 23. HV delivered by zip code for the South Bay Area regional case study.	121
Table 24. HV delivered by zip code for the Hanford 50% build-out regional case study..	122
Table 25. HV delivered by zip code for the Hanford 10% build-out regional case study. .	122

Acronyms and Abbreviations

AAEE	additional achievable electricity efficiency
AD	Anaerobic digestion
AED	Atomic emission detector
AGA	American Gas Association
ASTM	American Society for Testing and Materials
BTU	British thermal unit
Bcf	Billion cubic feet
C	Degrees Celsius
C2+	hydrocarbons larger than methane, “larger hydrocarbons”
CAPEX	Initial capital cost
CARB	California Air Resources Board
CARBOB	California Reformulated Gasoline Blendstock for Oxygenate Blending
CCST	California Council on Science and Technology
CEC	California Energy Commission
CH ₄	Methane
C ₂ H ₆	Ethane
C ₃ H ₈	Propane
CMAR	Carcinogenic, mutagenic, asthmogenic, or reproductive
CO	Carbon monoxide
CO ₂	Carbon dioxide
CPUC	California Public Utilities Commission
CRF	Capital recovery factor
CWC	Cellulosic waiver credits
DNV	Det Norske Veritas
EIA	Energy Information Administration
F	Degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
FID	Flame ionization detector
FVIR	Flammable Vapor Ignition-Resistant
GCV	Gross calorific value
GE	General Electric
GHG	Greenhouse gas
GJ	Gigajoule
g/mol	Grams per mole (molecular weight)
GTI	Gas Technology Institute
HHV	Higher heating value
H ₂ S	Hydrogen sulfide
HV	Heating value
IEA	International Energy Agency
Ind.	Industrial
IRD	Information Request Document

Acronyms and Abbreviations

km	Kilometer
kPa	Kilopascal
LBNL	Lawrence Berkeley National Laboratory
LCFS	Low carbon fuel standard
LCUG	Levelized cost of upgrading biogas
LDCs	Local distribution companies
LF	Landfill
LHV	Lower heating value
LNG	Liquified natural gas
LPG	Liquified petroleum gas
m ³	cubic meter
mg	Milligram
MJ	Megajoule
MMBTU	Million British thermal units (also MBTU)
mppcf	Million particles per cubic foot
MSW	Municipal solid waste
N ₂	Nitrogen
NCV	Net calorific value
n.d.	No data
NG	Fossil natural gas
NGC+	Natural Gas Council
NGLs	Natural gas liquids
nm	Nanometer
Nm ³	Normal cubic meter
NO _x	Nitrogen oxides
O ₂	Oxygen
OEHHA	California Office of Environmental Health Hazard Assessment
OH	hydroxyl
OPEX	annual operating costs
OSHA	Occupational Safety and Health Administration
PCBs	Polychlorinated biphenyls
PG&E	Pacific Gas and Electric
PIER	Public Interest Energy Research
PSA	Pressure swing adsorption
ppmv	Parts per million by volume
ppbv	Parts per billion by volume
psia	Pounds per square inch absolute
PSC	Public service commission
PUC	Public Utility Commission (of any state)
RASS	Residential Appliance Saturation Study
Re	Reynolds number
RFS	Renewable fuel standard
RINs	Renewable identification numbers
RNG	Renewable natural gas

Acronyms and Abbreviations

scf	Standard cubic feet
scfm	Standard cubic feet per minute
SG	Specific gravity
Si	Silicon
Sm ³	Standard cubic meters
SNG	Synthetic natural gas
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas
SDG&E	San Diego Gas and Electric
TLCC	Total life cycle cost
TS	Total solids
VOC	Volatile organic compound
WN	Wobbe number
WWTP	Wastewater treatment plant

Chapter 1

Scope of work

In pursuit of integrating a greater number of renewable energy resources into the energy supply and exploring avenues of reducing greenhouse gas emission sources in California, Assembly Bill 1900 (Chapter 602, Statutes of 2012) was chaptered into law by the California State Legislature in 2012. This bill required, among other things, that the California Public Utilities Commission (CPUC) develop standards for composition of biomethane intended for integration with the State's existing natural gas pipeline system. The purpose of standardizing these constituents was to ensure that the addition of biomethane to the natural gas pipeline will not threaten human health, pipeline integrity, or safety.

In support of the CPUC efforts to develop standards, the California Office of Environmental Health Hazard Assessment (OEHHA) compiled a list of constituents of concern found in biogas (the unprocessed precursor to biomethane) at significantly higher concentrations than in natural gas, and which could potentially pose a health risk. These constituents of concern would ultimately need to be addressed prior to integration with the State's existing natural gas infrastructure.

In 2014, the CPUC, through Decision 14-01-034, adopted gas quality specifications for the 12 biogas constituents of concern identified by OEHHA at the determined health-protective levels. In addition to these, the CPUC also adopted regulations for five additional "pipeline integrity protective constituents" proposed by utility companies serving the state. The CPUC's gas quality specifications included siloxanes in the list of considered pipeline integrity protective constituents.

In the wake of D-14-01-034, biomethane advocates believed that two gas quality specifications in particular posed significant and unjustified barriers to the economical utilization of biomethane in the state of California, including: (1) the biomethane minimum heating value (HV) adopted in 2006 in Decision 06-09-039; and, (2) the maximum biomethane siloxane concentration adopted in 2014 in Decision 14-01-034.

In September of 2016, the Governor of California approved Senate Bill 840 (SB 840). In SB 840, the legislature requested the California Council on Science and Technology (CCST) conduct a study analyzing regional and gas-corporation-specific issues relating to the minimum heating value and maximum siloxane specifications for biomethane addition to the common-carrier gas pipeline (Senate Bill 840, 2016). The study resulting from SB 840 would discover and analyze available information that could objectively resolve the barriers to the economic development of biomethane while also considering the health, safety, and pipeline integrity concerns existing among stakeholders.

In response to SB 840 (Budget Committee, 2016), the following report fulfills the legislative mandate. This study considers and evaluates:

1. The characteristics of various sources of biomethane and the distinctions between biogas, natural gas, and biomethane.
2. The rationale for existing and previous regulations of gas heating value, interchangeability, and siloxane content, as well as the gas quality specifications set forth by other states and gas companies, as compared to current California regulations.
3. The technical rationale for the minimum heating value specifications, including the impacts of those specifications on the cost, volume of biomethane sold, equipment operation, and safety of end users.
4. The scientific evidence justifying a maximum siloxane specification as well as topics concerning siloxane removal, potential human health impacts, and standard method development for measurement of siloxane compounds.
5. The impacts of minimum HV and maximum siloxane specifications on the cost to produce biomethane for pipeline addition in California.
6. The potential dilution of biomethane before and after it is injected into the pipeline.
7. The regional- and gas-corporation-specific concerns that may arise in widespread biomethane deployment scenarios.

Chapter 2

Natural gas and biomethane: Similarities and differences

Key points

- Natural gas (NG) is produced from naturally-occurring geologic formations and consists of a variety of components. Specific NG compositions are determined by the source material.
- Biogas is produced by anaerobic digestion (AD) of waste products such as agricultural waste, wastewater organic matter, and digestible materials in landfills. Like NG, biogas composition can vary and is determined by the composition of its source material.
- NG and biogas contain many of the same molecules, but in different quantities. Some molecules present in biogas are not present in NG, and vice versa.
- Presence or absence of certain molecules in a gas can affect combustion, safety, and equipment durability.
- Both NG and biogas are processed before they are introduced into long-distance gas transmission lines or into local distribution lines.

2.1 Sources of natural gas and biogas

Natural gas (NG) is a mixture of various gases produced from subsurface geologic reservoir rocks. The original source material for natural gas is ancient, buried organic matter. In most cases, NG contains mostly methane (a molecule containing one carbon atom and four hydrogen atoms, written as CH_4), ethane (C_2H_6), and propane (C_3H_8). Some NG streams contain appreciable quantities of larger hydrocarbon molecules (sometimes called C_{2+}). NG also typically contains some inert gases, chiefly carbon dioxide (CO_2) and nitrogen (N_2) as well as sulfur-containing molecules such as hydrogen sulfide (H_2S).

Biogas contains a mixture of CH_4 , CO_2 , and many other constituents. Raw biogas is a product of anaerobic digestion (AD) by microbes. After processing to remove non-combustibles and other contaminants, biogas is typically called biomethane or renewable natural gas (RNG).

Biogas is most typically generated from the decomposition of organic matter such as food waste, wastewater sludge, agricultural residues, or forestry waste by microbes in anaerobic

(non-oxygen-containing) environments. In some cases, biogas is produced in purpose-designed anaerobic digesters (e.g., in a dairy waste digester). In other cases, biogas is generated in less-managed conditions, such as deep in landfill materials where oxygen cannot quickly penetrate.¹ The microbes that produce biogas are not generally expected to produce C_2H_6 or other multi-carbon hydrocarbons present in NG.

2.2 Composition of natural gas and biogas

Natural gas composition varies depending on the geologic source of gas. CH_4 is the chief constituent, comprising 50–95% of the gas by volume. The larger hydrocarbon molecules (C_{2+}) are typically present in decreasing concentration with molecule size, with typical C_2H_6 concentrations of 10–15%. Gas with more C_{2+} hydrocarbons releases more heat per unit of volume combusted (see discussion below). Some natural gas deposits have high fractions of CO_2 , which must be reduced prior to sale.

Raw biogas composition depends on the feedstock material and the decomposition process used. Table 1. Theoretical biogas yield and composition by organic matter constituent. (TS = total solids, Nm³ = normal cubic meter, vol.% = mol%) (Weiland, 2010). provides theoretical values for biogas yield and composition based on broad classes of organic matter (Weiland, 2010). Note that greater fractions of CH_4 are possible when feedstocks are particularly high in fats and proteins. Table 2 shows the range of reported gas compositions by feedstock source material. Advanced digesters and blended feedstocks can improve CH_4 yield significantly; however, data for typical cases from the literature are used for the purposes of this report. Landfill (LF) gas typically has larger fractions of N_2 and O_2 , while a well-designed digester at a wastewater treatment plant (WWTP) or dairy farm can limit the intrusion of air, creating a mixture of mostly CO_2 and CH_4 .

Table 1. Theoretical biogas yield and composition by organic matter constituent. (TS = total solids, Nm³ = normal cubic meter, vol.% = mol%) (Weiland, 2010).

Feedstock material	Biogas yield (Nm ³ /tonne TS)	Biogas Composition (vol. %)	
		CH_4	CO_2
Carbohydrates	790-800	50	50
Raw protein	700	70-71	29-30
Raw fat	1200-1250	67-68	32-33
Lignin	0	0	0

1. We will not discuss alternative methods of producing gas from biomaterials, such as partial-oxidation or pyrolysis, as these are not expected to be economic in the near term and all commercial projects in North America for which there is information available utilize anaerobic digestion feedstock (see Section 5.3 and Table 9).

Table 2. Raw, pre-processing biogas composition for various sources of biogas.

Gas Composition	Source of Gas			
	WWTP	Landfill	Animal/ Agricultural Waste	Municipal Waste
Methane (CH ₄ , vol. %)	55-70% [1] 60-67% [3] 59.6% [6] 60% [7]	45-60% [1] 47-62% [3] 35-65% [4] 44% [5] 45% [7]	50-70% [1] 55-58% [3] 60-70% [4] 68% [7]	50-60% [2]
Carbon dioxide (CO ₂ , vol. %)	30-45% [1] 33-38% [3] 39.1% [6] 33% [7]	35-40% [1] 32-43% [3] 15-50% [4] 40.1% [5] 32% [7]	30-50% [1] 37-38% [3] 30-40% [4] 26% [7]	34-38% [2]
Nitrogen (N ₂ , vol. %)	<2% [3] 0.9% [6] 1% [7]	0-3% [1] 1-17% [3] 5-40% [4] 13.2% [5] 17% [7]	0-3% [1] 1-2% [3] 1% [7]	0-5% [2]
Oxygen (O ₂ , vol. %)	None [1] <1% [3] 0.2% [6] 0% [7]	0-2% [1] <1% [3] 0-5% [4] 2.6% [5] 2% [7]	<1% [3] 0% [7]	<1% [2]
Heating Value (BTU/scf)	500-640 [1]	410-550 [1]	450-650 [1]	450-550 [2]

[1] (Lampe, 2006), [2] (Bailón Allegue & Hinge, 2012), [3] (Rasi, 2009), [4] (Persson, Jonsson, & Wellinger, 2006), [5] (Jaffrin, Bentounes, Joan, & Makhlouf, 2003), [6] (Osorio & Torres, 2009), [7] (Favre, Bounaceur, & Roizard, 2009)

2.3 Differences in energy content between natural gas and biogas

Biomethane typically has a lower heating value (HV) than natural gas (see Box 1 for a technical discussion of heating value definitions). The HV is essentially the amount of heat released when a fuel is burned, and is most commonly presented in units of thermal energy per standard unit of volume. NG typically has a HV between 1000 and 1150 BTU/scf, depending on the composition. Raw biogas typically has a lower HV than NG due to: (1) smaller volume fraction of CH₄; (2) larger volume fraction of non-combustibles; and (3) the absence of multi-carbon hydrocarbons such as C₂H₆ and C₃H₈. For example, raw biogas with between 40–65 vol.% CH₄ and the remaining percentage being non-combustible components will yield a HV of 400–650 BTU/scf. After being upgraded to biomethane, the gas can contain greater than 95 vol.% CH₄ and have a HV in the range of 950–1010 BTU/scf. Given the major components of biogas, the highest biomethane HV attainable without the addition of multi-carbon hydrocarbons is approximately 1014 BTU/scf (evaluated as a real gas at 14.73 psia, 60 °F; see Box 1). contains the HV of gases present in natural gas and/or biogas. Throughout this work HV will be presented in units of British thermal units

per standard cubic foot (BTU/scf) to remain consistent with the regulatory language. U.S. regulatory practice uses “higher heating value” (HHV) to measure the energy content of gases, so all HVs will be measured on this basis for the purposes of this document (see Box 1).

NG typically has a HV between 1000 and 1150 BTU/scf, depending on the composition. Raw biogas typically has a lower HV than NG due to: (1) smaller volume fraction of CH₄; (2) larger volume fraction of non-combustibles; and (3) the absence of multi-carbon hydrocarbons such as C₂H₆ and C₃H₈. For example, raw biogas with between 40–65 vol.% CH₄ and the remaining percentage being non-combustible components will yield a HV of 400–650 BTU/scf. After being upgraded to biomethane, the gas can contain greater than 95 vol.% CH₄ and have a HV in the range of 950–1010 BTU/scf. Given the major components of biogas, the highest biomethane HV attainable without the addition of multi-carbon hydrocarbons is approximately 1014 BTU/scf (evaluated as a real gas at 14.73 psia, 60 °F; see Box 1).

Table 3. Molecular weights and heating value per standard cubic foot of associated gaseous compounds present in natural gas and/or biogas (real gas at natural gas industry standard conditions of 14.73 psia, 60 °F, and 1 scf; real gas behavior modeled using the Gas Processing Association (GPA) double summation method per GPA 2172-14).

Gas	Mol weight	Higher heating value
	g/mol	BTU/scf
CH ₄	16.04	1014.4
C ₂ H ₆	30.07	1788.8
C ₃ H ₈	44.09	2566.6
C ₄ H ₁₀	58.12	3373.2
N ₂	28.01	0
O ₂	32.00	0
CO ₂	44.01	0
H ₂ O	18.01	0

Box 1: Technical heating value definitions

Higher heating value (HHV) or gross calorific value (GCV) is the heat of combustion available by combusting fuels at standard conditions. Fuels are combusted in a bomb calorimeter, with all reactants starting at a standard temperature of 25 °C. The combustion products are then cooled back to standard temperature of 25 °C and the removed sensible heat is measured.

Lower heating value (LHV) or net calorific value (NCV) subtracts from the HHV the latent heat of vaporization of combustion water vapor at 25 °C. LHV represents an upper bound on the amount of energy available without condensing moisture in exhaust products and is a more practical measure of useful energy for many pieces of equipment.

In the United States, heating values for gas are typically presented in British Thermal Units per standard cubic foot (BTU/scf). In other global regions energy contents are measured in megajoules (MJ) or gigajoules (GJ), while volumes are reported in standard or normal cubic meters (sm^3 or nm^3).

Utility gas delivery specifications mandate HV limits based on BTU (measured on gross/higher basis) per standard cubic foot (at 14.73 psia and 60 °F). The remainder of this report refers to the HHV when discussing HV unless otherwise specified. For the purposes of this report, any calculations will be conducted at the conditions consistent with the utility gas delivery specifications (14.73 psia and 60 °F) and corrected for real gas behavior using the Gas Processing Association (GPA) double summation method (GPA 2172-14). Note that other methods do exist, such as American Society for Testing and Materials (ASTM International) 3588-98, which gives a value for pure methane of 1010 BTU/scf. ASTM 3588-98 differs from the GPA 2172-14 method by use of a different standard pressure (14.696 psia) and by use of the ideal gas approximation.

2.4 Presence of trace constituents in biogas and natural gas

In addition to the major components discussed above, there are many other trace constituents that are present in biogas or in NG. Trace constituents in biogas can include volatile metals (such as mercury and arsenic), ammonia, chlorinated compounds, and siloxanes. In NG, a variety of hydrocarbon compounds are present in small quantities, but these compounds are generally absent in biogas. Some of these trace constituents pose hazards to human health via inhalation or exposure to their combustion products. Other trace constituents have the potential to damage pipeline infrastructure or end-use NG-fueled equipment. For the purposes of this study, siloxanes will be the only trace constituent discussed, as this was the explicit interest of the enabling legislation, SB 840.

Siloxanes are a family of man-made compounds often containing oxygen and silicon (O-Si-O) bonds, with methyl (CH₃) groups bound to the silicon atoms. Siloxanes can be cyclic or linear in structure and are often referred to by abbreviations such as L2, D4, etc. In these abbreviations, the letter indicates the structure (linear, L or cyclic, D) and the number indicates the number of silicon atoms. Siloxanes are used in industry as anti-foaming agents and fire retardants. Additionally, siloxanes are used in many consumer products, such as deodorants and shampoos (Rasi, 2009). Due to their presence in consumer products, siloxanes are often found in biogas produced from wastewater and landfills. Siloxanes are generally not present in biogas produced from animal waste or agricultural residues. For the purposes of this study, siloxanes are expressed in units of mg Si per m³ (cubic meter) of gas (Box 2 further explains the units of measure for siloxanes) and Table 4 provides basic chemical compound information, as well as unit conversion factors for the most common siloxane compounds found in biogas.

Finding: Because of their broad use, siloxanes are often found in wastewater and landfills and therefore can be found in biomethane produced from wastewater treatment plants and landfills.

Table 4. Chemical characteristics and unit conversions of siloxane compounds.

Compound	Abbreviation	Formula	MW (g/mol)	1 ppm _v converted to mg Si/m ³	1 mg siloxane/m ³ converted to mg Si/m ³
Hexamethyldisiloxane	L2	C ₆ H ₁₈ OSi ₂	162	2.33	0.346
Octamethyltrisiloxane	L3	C ₈ H ₂₄ O ₂ Si ₃	236	3.49	0.356
Decamethyltetrasiloxane	L4	C ₁₀ H ₃₀ O ₃ Si ₄	310	4.66	0.361
Hexamethylcyclotrisiloxane	D3	C ₆ H ₁₈ O ₃ Si ₃	222	3.49	0.378
Octamethylcyclotetrasiloxane	D4	C ₈ H ₂₄ O ₄ Si ₄	297	4.66	0.377
Decamethylcyclopentasiloxane	D5	C ₁₀ H ₃₀ O ₅ Si ₅	371	5.82	0.377
Dodecamethylcyclohexasiloxane	D6	C ₁₂ H ₃₆ O ₆ Si ₆	445	6.99	0.378

Box 2: Technical siloxane unit definitions

Siloxane concentrations are generally reported in the units of ppm_v, mg siloxanes per m³, or as mg Si per m³. Because the concern is post-combustion silica formation potential, which is proportional to mass of Si, siloxane content will be presented in mg Si/m³ whenever possible.

Additionally, there can be other trace silicon-containing compounds present in biogas (silicates, silanols, etc.) which when combusted will also yield the formation of silica particulate. However, the focus of this work is on siloxanes, as this is what is currently regulated by the maximum permissible siloxane specification.

Observed siloxane concentrations in WWTP- and LF-derived raw biogas vary greatly depending on the feedstock material. Also, siloxane concentrations in raw biogas from a single site can vary hourly, daily, and seasonally (Baez & Hill, 2014). Siloxane concentrations for raw LF and WWTP biogases may vary from ~ 1 to ~ 100 mg Si/m³.

In addition to siloxanes, there can be other trace silicon-containing compounds present in biomethane (mainly silanols) which when combusted will also yield the formation of silica particulate. Only siloxanes are currently regulated as they typically are the most prevalent volatile silicon species in biomethane.

During combustion, siloxanes are fully oxidized to form SiO₂ (silica) molecules. Silica is a chief constituent of sand and rocks. After combustion, silica quickly condenses and is deposited in equipment as a white or gray solid (the melting point of pure silica is 1710 °C; it is lower in the presence of alkaline metals from ash). Silica deposition can cause a wide variety of operational issues, ranging from increased maintenance and decreased performance to complete failure.

2.5 Processing of natural gas and biogas

Both natural gas and biogas must be processed before introduction into long-distance transmission pipelines or local distribution lines. Processing ensures that gas in pipelines meets a variety of specifications pertaining to safety, reliability, and heat content.

Processing biogas into biomethane can yield energetic, financial, and environmental benefits. For example, end-use equipment tied to the NG grid is typically more energy-efficient than smaller on-site combustion equipment at a biogas generation facility (Pöschl, Ward, & Owende, 2010) including single and co-digestion of multiple feedstock, different biogas utilization pathways, and waste-stream management strategies was evaluated. The input data were derived from assessment of existing biogas systems, present knowledge on anaerobic digestion process management and technologies for biogas system operating conditions in Germany. The energy balance was evaluated as Primary Energy Input to Output (PEIO). Also, the ability to use gas on-site can be limited — if high volumes of biogas are produced, productive on-site use can be saturated. Biomethane designated for transportation end-use can also benefit financially from substantial incentives (e.g., California Low Carbon Fuel Standard (LCFS) credits and/or federal Renewable Identification number (RIN) credits). The production of low-cost, carbon-neutral heat and/or power from biogas can also provide substantial value as a flexible generation resource. Finally, sending biomethane to the pipeline allows for the decarbonization of energy end-uses for which there are no feasible low-carbon alternatives.

However, the process of upgrading biogas to biomethane is costly, and biomethane must meet strict requirements for pipeline access in order to ensure safe delivery to and consumption by, a wide range of possible consumers. For this reason, raw biogas is often consumed at the point of generation (“on-site”) without complete processing to biomethane.

In order to fulfill the objectives outlined in SB 840, the remainder of this report focuses specifically on the regulation of biomethane access to California pipelines for widespread use.

Chapter 3

Regulation of natural gas quality for safety and system integrity

Key points

- The quality of natural gas (NG) is regulated at both state and interstate levels for safety, reliability, and system integrity. Standards for gas quality are typically applied to gases as they are introduced to the pipeline system.
- Gas quality metrics examined in this chapter include heating value (HV), interchangeability, and siloxane content.
- Gas HV is regulated across North America to ensure expected delivery of energy to consumption devices.
- Gas interchangeability, defined as the ability to combust a new gas in existing appliances without degradation of combustion properties, is generally regulated separately from and less frequently than HV. A key metric of gas interchangeability is the Wobbe Index, but HV and other indicators are also used in conjunction with the Wobbe Index to assess interchangeability.
- Siloxane concentrations in gas are regulated because they affect the expected lifetime of combustion equipment through deposition of silica.
- The current minimum heating value specifications in California are 990 BTU/scf in Southern California and “consistent with historical values” in Northern California. These were adopted in 2006, prior to which lower HV specifications were applied.
- The current maximum siloxane specification, which was enacted in 2014, is 0.1 mg Si/m³ for both Southern and Northern California.

3.1 The need for gas quality regulation

A modern gas distribution system can serve millions of end-user combustion devices. These devices range from small-scale, infrequently-used devices (e.g., natural gas barbecue grills), to large-scale industrial equipment used nearly continuously (e.g., oil refineries). Because of the wide range of equipment connected to the gas system, the quality of gas in pipelines is regulated to ensure consistency of combustion.

Gas quality regulations are most commonly applied at the point of receipt, where gases are introduced to the system (AGA, 2009). Point-of-receipt regulation ensures that gas quality will meet specifications regardless of changes in flow conditions. A smaller number of pipeline systems regulate gas quality at the point of delivery, or where consumers or downstream pipelines take custody (AGA, 2009). Chapter 6 explores the possibility of diluting non-compliant biomethane with NG from the pipeline to ensure that the produced gas meets specifications before it reaches end-users.

A variety of gas quality regulations exist. In the U.S., gas companies develop gas quality specifications for their system. These specifications are then approved by relevant regulatory bodies. For interstate pipelines, the proposed quality specifications, or tariff, is approved by the Federal Energy Regulatory Commission (FERC). Intrastate pipelines and local distribution companies (LDCs) typically have their specifications approved by a state-level, public utilities commission (PUC) or public service commission (PSC).

The specific gas quality regulations discussed in this chapter include minimum HV, gas interchangeability, and siloxane content.

3.2 Regulation of gas heating value

Minimum HV is regulated to ensure that gas used by consumers provides the appropriate energy content required by commonly-used equipment. A complete survey of publicly-available gas quality tariff information was published by the American Gas Association (AGA) in the 2009 AGA Report 4A, covering all tariff data for U.S. and Canada (AGA, 2009). In total, 138 companies are represented by 224 data points (some companies have tariffs that vary by region or pipe system). The distribution of minimum HVs is shown in . The most common specification bin is 950 to 974 BTU/scf, containing 146 out of 224 data-points.

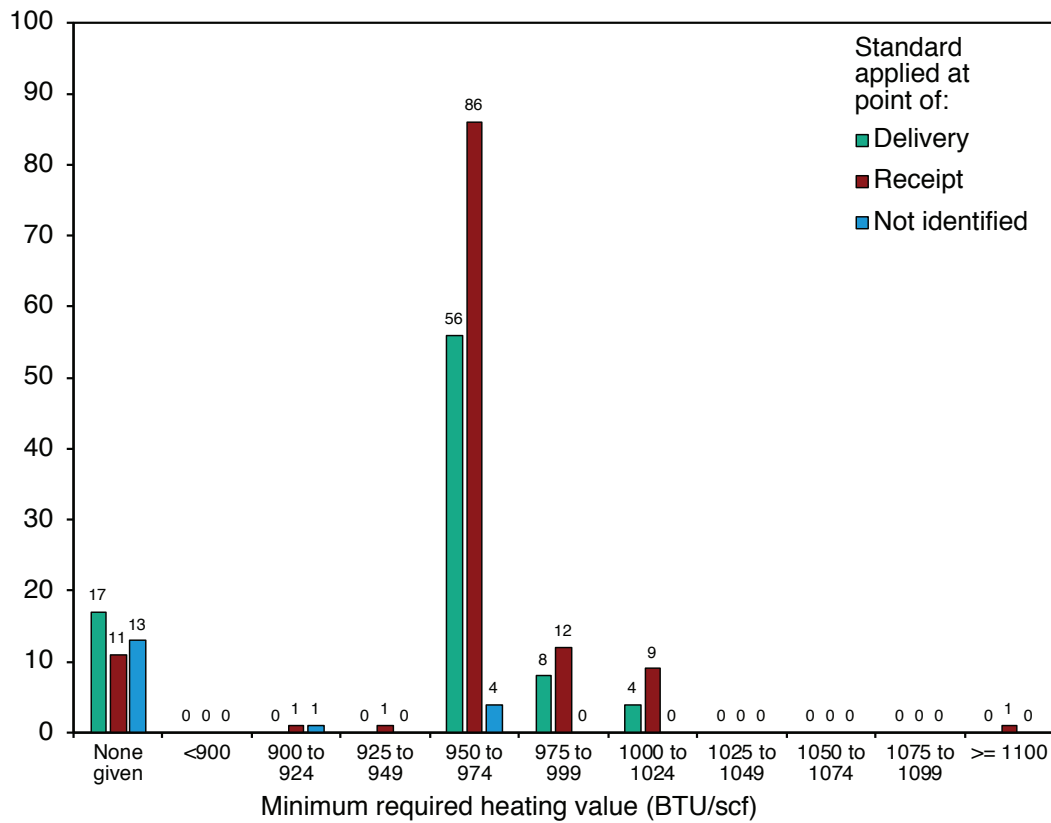


Figure 1. Reported minimum HV specifications from tariffs surveyed in AGA 2009 survey of North American gas systems.

Note that even if a pipeline or utility has a minimum HV of 950 BTU/scf, this does not imply that gas with HV of 950 BTU/scf is actually delivered in that system. There is no organized database of delivered HVs across the hundreds of separately regulated regions. Also, reporting varies by pipeline system in all aspects including data quality, sampling frequency, and accessibility of historical data. Definitive assessment is therefore outside the scope of this work.

Although regulation of HV is more common, the objective of ensuring safe combustion by end-users is best achieved through regulation of gas interchangeability (NGC+, 2005) and forecasts are for future imports to be a significant percentage of total North American supply. Regasification terminals have regained active status and are expanding. The National Petroleum Council's 2003 report "Balancing Natural Gas Policy" presented projections for LNG imports to increase from 1 percent of our natural gas supply in 2003 to as much as 14 percent by 2025. This report also recommended that FERC and DOE "update natural gas interchangeability standards." 1 The characteristics of natural gas supply in North America have evolved over time as conventional sources are depleted, and new sources in the Rockies, Appalachians and the Gulf of Mexico are developed. Direct receipt of unprocessed gas by transmission

pipelines has grown and also contributed to the change in the natural gas composition. Finally, the United States has also experienced prolonged periods of pricing economics that make it more profitable to leave some natural gas liquids (NGL's). As HV is a component of interchangeability, they are related concepts, but different metrics are used for regulation of gas interchangeability.

3.3 Regulation of gas interchangeability

Replacing one gaseous fuel with another of different composition can affect the safety and reliability of combustion. Impacts to combustion associated with the switching of gaseous fuel are assessed using metrics of gas interchangeability.

Interchangeability is defined as “the ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency, performance or materially increasing air pollutant emissions” (NGC+, 2005). The integration of biomethane into the natural gas supply of California has raised concerns about the interchangeability of the two products when appliances have been tuned to receive gas of the quality historically delivered (NGC+, 2005).

The combustion phenomena that affect interchangeability include (NGC+, 2005):

- Auto-ignition (engine knock),
- Flashback,
- Lifting,
- Blowout,
- Incomplete combustion leading to carbon monoxide (CO) formation,
- Yellow tipping,
- Emissions of nitrogen oxides (NOx), unburned hydrocarbons, and CO.

The Wobbe Index (also called Wobbe Number or Wobbe) is one of the most common metrics of interchangeability. The Wobbe measures the rate of energy delivered through a fixed orifice at a constant pressure. The Wobbe is calculated by dividing the higher heating value (HHV) of the gas by the square root of the specific gravity (SG) of the gas relative to air. Neither HV nor Wobbe alone can completely address combustion over the full range of natural gases (NGC+, 2005). In practice, HV and Wobbe must be examined together to specify an acceptable range of gas to avoid interchangeability concerns for end-use customers.

Most of the above combustion dynamics are concerns at the upper bound of interchangeability (at maximum HV or Wobbe). Incomplete combustion, flashback, yellow-tipping, and engine knock are all controlled by placing maximum limits on the Wobbe and HV. The minimum Wobbe number limit controls for flame lifting, which can lead to CO formation and blowout. Given the low HV and Wobbe of biomethane compared to NG, flame lifting, formation of CO, and blowout are the primary concerns when interchanging NG with biomethane.

Flame lifting may occur when an increase in inert components in a fuel gas decreases the rate of energy delivered to the point of combustion while simultaneously increasing the flow rate of gas through the burner tip. This can cause the flame to “lift” off the burner tip. This lifting may allow for some fuel to escape with only partial oxidation, leading to CO emissions or blow out (extinguishment) of the flame.

In addition to the Wobbe, other interchangeability metrics exist. Most importantly, the American Gas Association (AGA) developed a set of interchangeability indices in Research Bulletin 36: *Interchangeability of Other Fuel Gases with Natural Gases* (AGA, 2002). The AGA indices include a flame-lifting index. In addition to the AGA indices, Elmer Weaver developed the Weaver indices for interchangeability in *Formulas and Graphs for Representing the Interchangeability of Fuel Gases* (Weaver, 1951).

To ensure reliable application of these various metrics, an interchangeability operating regime (Figure 2. Conceptual map of interchangeability impacts as a function of Wobbe Number (vertical axis) and heating value (HV, horizontal axis). Reproduced from (NGC+, 2005).) was developed by the Natural Gas Council (NGC+) Interchangeability Work Group (NGC+, 2005). The group notes that “a purely scientific approach might lead one to applying many of the Weaver and AGA Bulletin 36 indices for every end-use application. However, limited testing data on low emission combustion equipment indicate that these indices may not consistently account for the observed combustion related behavior.” The NGC+ group recommended interim guidelines to conservatively ensure interchangeability: a range of +/- 4% Wobbe variation from the local historical average gas, and a maximum heating value limit set at 1110 BTU/scf (NGC+, 2005). Only eight of the 224 surveyed tariffs in the 2009 AGA study contained minimum Wobbe limits (AGA, 2009).

Finding: The NGC+ Interchangeability Work Group determined the WN is the most efficient and robust single interchangeability index. Their interim guidelines specified a WN range of +/- 4% from the local historical average gas. These guidelines were implemented in Rule 30 and, along with the AGA lifting index, are sufficient to define the range of interchangeable biomethane supplies.

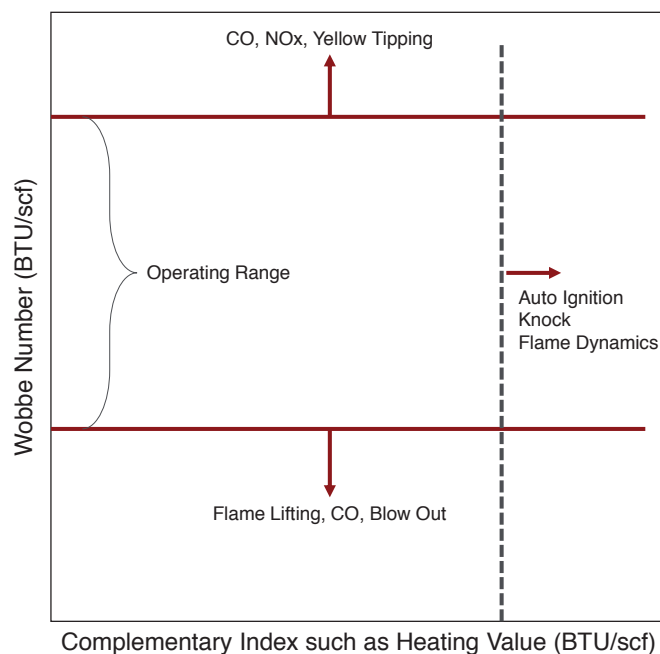


Figure 2. Conceptual map of interchangeability impacts as a function of Wobbe Number (vertical axis) and heating value (HV, horizontal axis). Reproduced from (NGC+, 2005).

3.4 Regulation of gas siloxane content

Siloxane content is regulated because silica deposits cause numerous problems. Silica can build up on heat exchanger surfaces, can clog narrow tubes, and can lead to abrasion of internal surfaces of turbines and engines. Silica particles can also collect in the oil of engines and require more frequent oil changes. Also, because silica is both a thermal insulator and an electrical insulator, silica can lead to deactivation of key sensors and localized overheating (Dewil, Appels, & Baeyens, 2006). In fuel cell systems, silica particles can clog the catalytic fuel processing reactors and porous electrodes leading to performance degradation. Lastly, post-combustion emissions control catalysts (i.e., selective catalytic reduction (SCR) catalysts for NO_x control) are highly susceptible to fouling by silica as the particulates will clog the pores of the catalyst bed and deactivate catalyst active sites (Nair et al., 2012).

Siloxane specifications vary between countries. Many countries, including Belgium, France, Germany, Poland, Sweden, Switzerland and the U.K., do not have a numerical siloxane specification in place. However, Austria, Germany, Poland, and Switzerland all ban any pipeline addition of gas from landfills, wastewater sources, or both. These specifications are summarized in Table 5. International siloxane specifications for grid injection of biomethane. below.

Table 5. International siloxane specifications for grid injection of biomethane.

Country	Maximum Siloxanes (mg Si/m ³)	Notes	Source
Austria	4	LFG and sewage gas injection forbidden	[1], [2]
France	No specification	Sewage sludge substrates are excluded for grid injection	[1], [2]
Belgium	No specification	-	[2]
Czech Republic	6	-	[1], [2]
Germany	No specification	LFG injection forbidden	[1], [2]
Netherlands	0.1	-	[4]
Poland	No specification	Landfill and sewage gas are restricted from grid	[3]
Sweden	No specification	Focus on vehicle fuel due to low coverage of NG grid	[1], [2]
Switzerland	No specification	LFG injection forbidden	[1], [2]

[1] Green Gas Grids Website, [2] (Svensson, 2014), [3] (Bailón Allegue & Hinge, 2012), [4] Personal Communication with Howard Levinsky, DNV GL.

The reason for the bans is unclear in many cases. Germany has restricted the pipeline access for landfill gas, citing the risk of forming dioxins and furans during combustion (DVGW G262), and instead utilizes these resources in on-site combined heat and power (CHP) generators. Of countries with numerical siloxane specifications, the Netherlands has a specification equal to the Rule 30 limit of 0.1 mg Si/m³, while the remaining countries have less stringent requirements than California.

The European Committee for Standardization produced a specification in 2015 that set the maximum siloxane content as either 0.1 mg Si/m³ or 0.5 mg Si/m³. The committee concluded further research is needed to decide on whether the higher limit value is acceptable (CEN/TC408, 2015). More recent developments placed the specification at 0.3 mg Si/m³, in part due to concerns about measurement precision.

In 2012, the Canadian Gas Association convened a Standing Committee on Operations Biomethane Task Force (Engler, Feltham, & Tweedie, 2012). Their guidance document outlined a maximum allowable siloxane of 1 ppm_v, equivalent to 2.5 – 6.2 mg Si/m³ (converted as all L2 or all D5, respectively). The committee balanced the technical limitations of measurement against the potential damage to end-use equipment. The 1 ppm_v level was derived by taking an agreed-upon detection limit (0.5 ppm_v) and doubling it such that the concentration can be reliably achieved and verified in a nondiscriminatory manner, while minimizing risk of damage to equipment.

3.5 Current California regulations of gas quality

The California Public Utilities Commission (CPUC) regulates California gas-grid quality specifications. In 2014, the CPUC reaffirmed the use of “Rule 30” governing Southern California gas quality and “Rule 21” governing Northern California gas quality (PG&E, 2015; SoCalGas, 2015).

Per Rule 30, any gas entering the pipeline system of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E) must have a HHV of no less than 990 BTU/scf (SoCalGas, 2015, p. 17). Per Rule 21, the gas quality specifications for Pacific Gas & Electric (PG&E) state “the gas shall have a heating value that is consistent with the standards established by PG&E for each Receipt Point” (PG&E, 2015, p. 17). Sacramento Municipal Utility District (SMUD) currently only accepts local biomethane via functionally-dedicated pipeline, but has expressed that they ensure the gas delivered meets the Rule 21 specifications.

Minimum HV specifications cannot be analyzed in isolation from other gas specifications, as allowable HV is also affected by the other specifications. For example, in SoCalGas and SDG&E territory, the Rule 30 specifications mandate a maximum of 4% inert constituents by volume. According to Rule 30, biomethane also must meet a minimum Wobbe of 1279 BTU/scf and a maximum AGA lifting index of 1.06.

In PG&E territory, Rule 21 specifications mandate that HV be “consistent with the standards established by PG&E at the point of receipt” and that gas must be “interchangeable with the gas in the receiving pipeline” in accordance with AGA Bulletin 36 (PG&E, 2015, p. 16).

This divergence between the Rule 21 and Rule 30 specifications is important in their effects on acceptable gas quality from biomethane producers. Due to regional variations in the historical NG delivered, safety objectives may be best achieved by regulating in the manner that Rule 21 does, with a blanket statement that HV and Wobbe must be within acceptable deviation from the historical gas at this point. However, the imposition of clear, numerical bounds, as in Rule 30, may result in improved information symmetry, greater transparency, and ensure equitable treatment of potential biomethane suppliers.

The maximum siloxane specifications adopted in both Rules 21 and 30 are as follows:

- Trigger Level: 0.01 mg Si/m³
- Lower Action Level: 0.1 mg Si/m³
- Upper Action Level: unspecified

According to the text of Rule 30, the Trigger Level is the level at which additional periodic testing and analysis of the constituent is required. If siloxanes are found to be above the Trigger Level of 0.01 mg Si/m³, then the gas must be tested for siloxanes quarterly (at least once every three-month period). This testing frequency can be reduced to once every 12 months if the testing displays siloxane concentrations below the Trigger Level in four consecutive, quarterly tests. The Lower Action Level is used to screen biomethane during the initial biomethane quality review and as an ongoing screening level. Prior to injection, the producer must conduct two tests over a two- to four-week period (SoCalGas, 2015). To qualify for a pipeline interconnect, both tests (conducted by an independent certified third-party laboratory) must reflect that the biomethane siloxane content is below the Lower Action Level. Gas failing to meet the Lower Action Level three times in a 12-month period will be shut-off, until such a time as independent testing reflects the gas is below the Lower Action Level. The Upper Action Level, where applicable, establishes the point at which the immediate shut-off of the biomethane supply occurs (SoCalGas, 2015, p. 20). When a biomethane producer is found non-compliant and shut-in, the biomethane will not be able to be introduced to the pipeline. In this case, the gas will instead need to be redirected to a flare or used in other on-site combustion equipment.

3.6 California regulatory history

3.6.1 California minimum HV specification

The current minimum HV specification was established in the CPUC Decision 06-09-039 on September 21, 2006, and upheld in Decision 14-01-034 on January 16, 2014 (CPUC, 2006, 2014). The later decision was prompted when biomethane developers requested the minimum HV specification be reduced to accommodate the lower characteristic HV of biomethane. Arguments presented by biomethane developers were as follows:

1. Other states maintain lower minimum HV specifications than California without ill effects.
2. Biomethane does not contain the longer hydrocarbons that give NG a higher HV.
3. It is cost prohibitive to add propane or other higher hydrocarbons to augment the HV of biomethane, and doing so would partially offset the climate benefits of biomethane.
4. The minimum HV specification in California was 970 BTU/scf before 2006. It was increased to 990 BTU/scf in 2006 by regulatory decision to accommodate anticipated imports of liquefied natural gas (LNG), which typically has a higher HV than domestic gas supply.

The CPUC cited Decision 06-09-039 which involved a greater number of stakeholders in adjudicating the HV requirement. The CPUC cited interchangeability concerns and the

lack of evidence that a less stringent HV specification would have a negligible effect on end-users. The CPUC then elected to uphold the minimum HV specification of 990 BTU/scf (CPUC, 2014).

Decision 06-09-039 was made in part with the objective of addressing interchangeability concerns brought about by the expected increase of LNG entering into California's NG supply. As such, discussion focused on specifications for maximum and minimum Wobbe Number for NG entering California's pipelines (see Section 3.3 discussion on interchangeability). The only unique public argument presented for the increase of minimum HV specification from 970 to 990 BTU/scf was submitted by the SDG&E and SoCalGas utilities. The text from the Final Decision stated the following:

“SDG&E/SoCalGas advocate increasing the minimum heating value from 970 BTU/scf to 990 BTU/scf, while maintaining a maximum of 1150 BTU/scf, all on a dry basis. The current minimum heating value, they assert, was adopted in anticipation of Synthetic Natural Gas supplies coming from coal gasification plants during the energy crisis of the 1970s. Since the anticipated supply never came to pass, SDG&E/SoCalGas advocate raising the standard to reflect the characteristics of today's gas supply.” [D. 06-09-039, p. 115]

This logic is parallel to the current arguments of biomethane proponents, with respect to imports of LNG that never came to pass. The only other stakeholder that provided comment on the HV specification during proceedings for Decision 06-09-039 was Calpine Corporation, an electricity generator with a large presence in California. Calpine proposed much wider and less stringent HV specifications, citing the specifications for their turbines from General Electric (GE) and Siemens:

“Calpine's proposed specifications also include adopting a minimum and maximum heating value range of 900 to 1,200 BTU/scf, maximum ethane of 15 percent, maximum propane of 2.5 percent, maximum butane of one percent, and maximum inerts of 15 percent. Calpine also based these specifications on GE and Siemens DLN/DLE gas turbine specifications.” [D. 06-09-039, p. 144]

The HV specification proposed by SDG&E/SoCalGas was adopted:

“We will adopt SDG&E/SoCalGas' proposal to increase the minimum allowed heating value from 970 BTU/scf to 990 BTU/scf. We will not change the maximum allowed heating value which is now 1150 BTU/scf since no party argued for changing this standard. Calpine proposed minimum and maximum heating values of 900 and 1200 BTU/scf respectively, and our adopted requirements will be within that range.” [D. 06-09-039, p. 161].

3.6.2 California maximum siloxane specification

The maximum siloxane specification was adopted in Decision D-14-01-034 along with several other constituents of concern (CPUC, 2014). Prior to this proceeding, twelve constituents of concern that can potentially be present in biomethane were examined by a joint report produced by the California Air Resources Board (CARB) and the Office of Environmental Health Hazard Assessment (OEHHA) (CalEPA, 2013). The constituents included antimony, arsenic, copper, p-Dichlorobenzene, ethylbenzene, hydrogen sulfide (H_2S), lead, methacrolein, n-Nitroso-di-n-propylamine, mercaptans, toluene, and vinyl chloride. These twelve constituents were deemed to have environmental or human health impacts and maximum permissible concentrations were included in this proceeding. In addition, the utilities proposed the inclusion of five constituents they claimed posed potential risks to the integrity and safety of the gas pipelines and pipeline facilities. The five constituents are siloxanes, ammonia, hydrogen, mercury, and biologicals. Siloxanes were included on this list due to risk of equipment damage and catalyst poisoning. The CPUC adopted the regulations proposed by the utilities for these five additional constituents, at the levels recommended by the utilities.

Chapter 4

Assessment of evidence for the current California heating value specification

Key points

- Empirical evidence from literature contains several data points supporting the safe operation of appliances and commercial equipment at a HV of around 970 BTU/scf after switching from a higher HV baseline gas.
- Because pure CH_4 has a heating value of ~ 1014 BTU/scf and biomethane contains no C_{2+} hydrocarbons, biomethane must be purified to 98% CH_4 to meet the current specification. Allowing a specification of 970 or 950 BTU/scf would allow biomethane of 96% and 94% purity, respectively.
- Under the current gas quality specifications in California, the minimum HV specification is the most restrictive metric for production of biomethane with an acceptable major component composition.
- Relaxing the HV specification to a level near 970 BTU/scf will not affect safety if NGC+ recommendations on Wobbe deviation from adjustment gas, or the maximum AGA lifting index, are not exceeded.
- Relaxing the HV specification to a level near 950 BTU/scf could affect safety as it would result in excessive Wobbe deviation and exceed the maximum AGA lifting index.

4.1 Experimental literature on HV and interchangeability

Several experimental studies have examined impacts of changing the HV of gaseous fuels. These studies are summarized in Table 6. Interchangeability studies from empirical literature (n.d. = no data). This table only includes studies that examined lower bounds on HV. (see Appendix A for more information). The majority of published studies focus on upper bounds of HV or Wobbe (Singer, 2006; SoCalGas, 2005). This is because these studies were investigating introduction of liquefied natural gas (LNG) imports, which have high HV and Wobbe.

We examine empirical evidence for four chief concerns of lower HV gas:

1. Flame lifting leading to incomplete combustion and CO emissions;
2. Changes to ignition properties leading to engine knock;
3. Increased presence of CO₂ leading to corrosion and safety concerns;
4. Changes to heat content leading to poor performance of temperature-sensitive processes.

The first concern regarding use of low HV gas is flame lifting leading to incomplete combustion and emissions of CO and other products of incomplete combustion. A California Energy Commission (CEC) Public Interest Energy Research (PIER) report surveyed interchangeability impacts in residential and commercial appliances (Singer, 2006). They conclude: “There are almost no reports of lifting occurring with appliances operating [in a steady-state] (warmed) mode. This is true even for large changes (reductions) in Wobbe from [sudden introduction of a] substitute gas.” An AGA study is further cited to support that lifting is resolved as the appliance warms (Singer, 2006).

A more recent CEC-sponsored study examined industrial combustion equipment. Simulations were used to examine emissions and lean blow-off stability performance under varying fuel composition for nine industrial combustion devices (Colorado & Mcdonell, 2017). The study found that, at a constant fire rate¹, addition of CO₂ to the fuel yields a reduction in NO_x production as well as a reduction in flammability limits (the flame will blow-off at a higher equivalence ratio). The equivalence ratio is defined as the ratio of the actual fuel:air ratio to the stoichiometric fuel:air ratio. When a fuel is burned at stoichiometric conditions (all O₂ is consumed in combustion), the equivalence ratio is 1. Increasing the amount of excess air will decrease the equivalence ratio and eventually cause the flame to lift and blow-off. The study displayed that as the vol.% CO₂ of the fuel gas increases, this blow-off phenomenon will occur at a higher equivalence ratio (less excess air). However, according to their simulations, they find that “the addition of CO₂ to NG up to 20% does not affect significantly the stability of the system” (Colorado & Mcdonell, 2017).

The second concern is impact of gas composition on ignition properties of gas, particularly for vehicle applications. Natural gas vehicles may be an initial end-use for biomethane due to substantial policy incentives for biofuels in transportation (see Chapter 6). Natural gas vehicles typically specify a minimum CH₄ number. CH₄ number quantifies the fuel’s resistance to engine knock by measuring the amount of methane relative to longer chain hydrocarbons. As biomethane does not contain larger hydrocarbons, it will not be challenged by minimum CH₄ number specifications.

1. The flow rate of fuel gas automatically adjusts to ensure a constant delivery of energy even as it is diluted with CO₂.

A third concern is the impact of biomethane on pipeline integrity and safety. Safety could be affected if the lower HV or Wobbe of biomethane is caused by a higher fraction of CO₂, due to corrosive properties of CO₂ (Kermani 2003). For this reason, maximum CO₂ content is often regulated additionally and separately from minimum HV specifications (see Section 4.4.3). There is no reported evidence for pipeline safety concerns due to the lower HV of biomethane if relevant corrosion specifications are met (moisture content, O₂ vol.%, CO₂ vol.%). However, these concerns somewhat limit feasible biomethane compositions through maximum CO₂ restrictions.

Lastly, the lower heat delivery potential of lower-HV biomethane could be a concern for temperature-sensitive processes. Equipment in which combustion is controlled via a thermostat should not be affected, as a longer heating time can compensate for lower-HV fuels. However, timed processes may be affected. For example, if industrial cooking or grill equipment is operated via timer instead of controlled via a combination of thermostat and timer, the resulting food may be undercooked (SoCalGas, 2005).

Three studies have examined the impact of lower-HV fuels on cooking (Hernandez et al., 2017; SoCalGas, 2005). SoCalGas sponsored three studies (SoCalGas 2005, 2011, 2017) examining gas at 970, 960/963, and 974 BTU/scf respectively. In these three studies the baseline gas varied from 1020, 1023, and 1160 BTU/scf. No impacts were observed in the most recent study with the test gas at 974 BTU/scf, while earlier studies at lower HVs showed undercooked beef patties.

No information was found regarding the preponderance of cooking equipment in California that lacks appropriate temperature controls and that therefore could result in undercooked food. Environmental factors may also have an impact on the sensitivity to these issues, including changes in ambient temperature, the temperature of food before cooking, etc. Best practice would be for the utility to inform customers of expected abnormalities in gas HV, so their process can be monitored and adjusted if needed.

Table 6. Interchangeability studies from empirical literature (n.d. = no data). This table only includes studies that examined lower bounds on HV.

Source	Appliances	Baseline Gas (BTU/scf)		Test Gas (BTU/scf)		Comments
		HV	WN	HV	WN	
PG&E (Estrada Jr., 1996)	4 ranges, 2 forced air furnaces, 2 wall furnaces, 2 water heaters	995	n.d.	950	n.d.	Acceptable limit for minimum HV found at 950 BTU/scf.
AGA (Griffiths, Connely, & Deremer, 1982)	Tank water heaters (14), Central furnaces (15), Range burners (4), Oven/broiler sets (4), Clothes dryer (1), Boilers (5), Room heater (1), Deep fat fryer (1), Infrared broiler(1)	1064	1296	961	1179	Very little, if any, lifting observed on the lifting limit gas.

Source	Appliances	Baseline Gas (BTU/scf)		Test Gas (BTU/scf)		Comments
		HV	WN	HV	WN	
SoCalGas (SoCalGas, 2005)	Legacy water heater, Floor furnace, Wall furnace, Condensing forced air furnace, FVIR water heater, Instant water heater, Pool heater, Commercial condensing boiler, Commercial hot water boiler, Low-NOx commercial/ind. steam boiler, Ultra-low-NOx commercial/ind. steam boiler, Deep fat fryer, Timed char-broiler	1020	1330	970	1271	No performance issues observed with rapid switching of gases. All equipment operated safely and performed satisfactorily when tuned with baseline gas and then operated with the low BTU test gas. Timed processes were found to be sensitive as burgers were undercooked on the chain-driven char broiler.
SoCalGas (CPUC Testimony, 2011)	Commercial range top burner	1013	1332	935	1203	Two ports in the bottom back of burner had continuous flame lifting, one port had intermittent lifting.
				950	1195	Two ports in the bottom back of burner had continuous flame lifting, one port had intermittent lifting.
	Commercial radiant burner	1015	1335	960	1266	Upper part of burner became less radiant, burner started showing flame lifting on the bottom.
				909	1177	Bottom part of burner has considerable flame lifting, CO increased noticeably.
				934	1203	N2 dilution of pipeline gas. Bottom part of burner showed considerable flame lifting.
				952	1202	CO2 dilution of pipeline gas. Bottom part of burner showed more flame lifting with CO2 dilution than N2 dilution.
	Commercial char-broiler	1023	1345	963	1210	Cooked hamburgers for a total of 12.5 minutes. Beef patties were visibly undercooked
		1023	1345	960	1203	Cooked hamburgers for a total of 9.5 minutes. Beef patties were visibly undercooked, pink in the center.
SoCalGas (Hernandez et al., 2017)	Convection Oven, Broiler, Fryer, Griddle	1150	1385	974	1279	Final average food product temperatures were not statistically different from each other, cooking appliances exhibited no ignition, operational or safety problems during testing, no gas orifice or air shutter adjustments were required to operate properly when using simulated biomethane

4.2 Review of data on California appliances and equipment in place

Potential interchangeability impacts depend on what equipment is tied to the natural gas pipeline. Unfortunately, limited information is available on California's stock of combustion equipment.

According to the most recent California Residential Appliance Saturation Study (RASS) (Palmgren, Stevens, Goldberg, Bames, & Rothkin, 2010), the most common residential uses of natural gas in California are space heating and water heating. Residential appliances, specifically ranges, water heaters, and furnaces, have been tested the most thoroughly in the literature as they are believed to be the least likely to be regularly maintained and tuned for proper combustion.

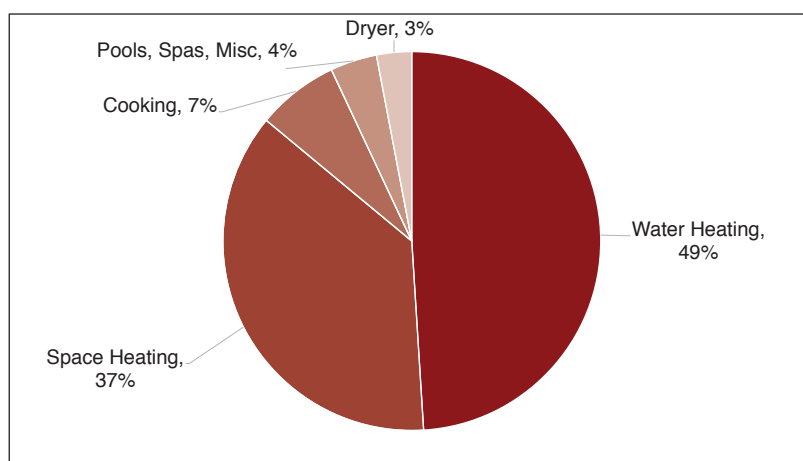


Figure 3. Statewide residential natural gas consumption by use (Palmgren et al., 2010).

A study of industrial appliances was conducted by the Gas Technology Institute (GTI) and Lawrence Berkeley National Laboratory (LBNL) to investigate potential interchangeability concerns with LNG use in industrial burners. This report provided a breakdown of natural gas consumption from the industrial sector (Rue et al., 2011). All experiments were conducted with Wobbe numbers that varied above the adjust gas, so the experimental results are not directly generalizable to biomethane.

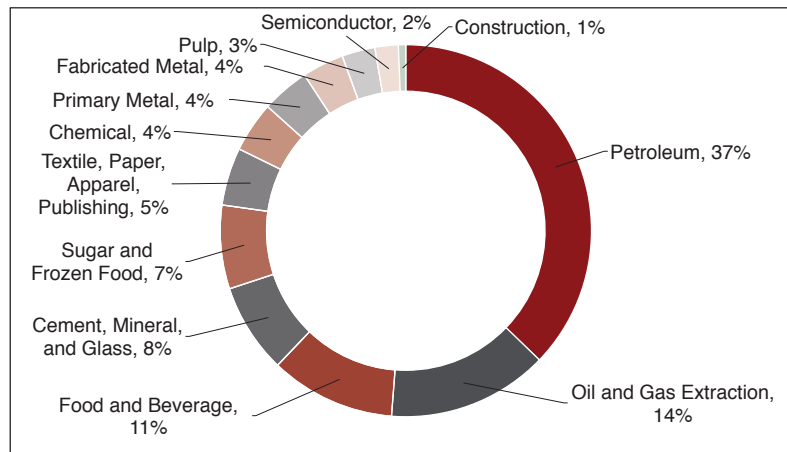


Figure 4. California statewide industrial natural gas consumption by sector (Rue et al., 2011).

Conversations with retailers of natural gas appliances and representatives from SoCalGas suggest that most residential and commercial appliances are tuned by the manufacturer and not tuned upon installation. However, anytime an appliance is adjusted, it is being tuned to the gas delivered at that particular time.

4.3 Review of historical heating value delivered in California

It is typically assumed that existing appliances are tuned to receive the historical composition of pipeline natural gas. Thus, determining the likelihood of interchangeability hazards requires understanding of the historical quality of the gas delivered to consumers. The Energy Information Administration (EIA) reports monthly average HV of natural gas consumed in California (Figure 5. Historical monthly average HV of natural gas delivered in California (EIA, 2018).). Monthly averages have ranged from 1020 BTU/scf to 1040 BTU/scf since 2013 (EIA 2018). These fluctuations are caused by many factors: differing composition of new NG sources, seasonal demand variation, and changing prices of NG constituents in competing commodity markets such as petrochemical feedstocks.

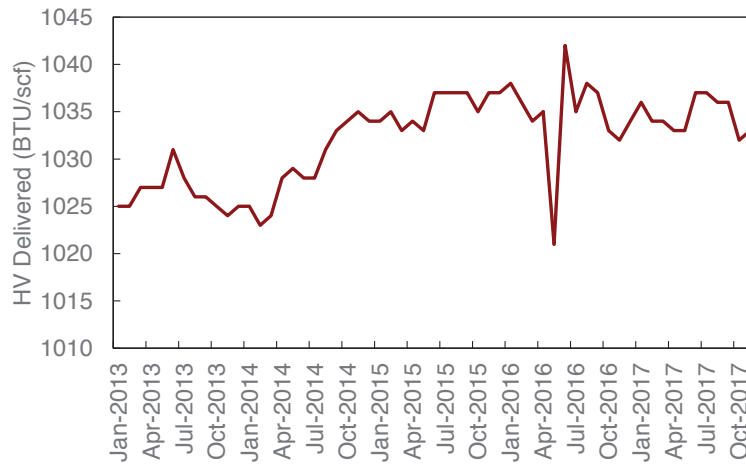


Figure 5. Historical monthly average HV of natural gas delivered in California (EIA, 2018).

Each LDC territory in California also reports historical HV data. LDCs report geographic variation in delivered natural gas HV. PG&E service territory is divided into BTU Districts with differing average HV. PG&E publishes weekly averages of the HV and specific gravity of the gas delivered in each BTU district. SoCalGas and SDG&E also have different thermal zones or BTU districts. SoCalGas publishes monthly Billing Factors to adjust customer billing for deviations in HV (billing factors can be multiplied by 1000 to equal BTU/scf).

A 10-year record of HVs from 220 BTU districts was obtained from PG&E with the assistance of the CPUC. Weeks with missing data were omitted from the analysis. (See Figure 5 for distribution and summary statistics.) Over half of PG&E's BTU districts have a historical average between 1015 and 1027 BTU/scf. The median observed HV in PG&E service territory is 1021 BTU/scf.

Historical monthly SoCalGas billing factors were acquired from June 2012 to March 2017 (see Figure 6. Historical HVs in PG&E BTU districts during the period November 2007 to November 2017 (Left). Distribution of HV in SoCalGas service territory during the period June 2012 to March 2017.). Across the 51 different BTU districts, the five-year historical averages range between 1015 and 1080 BTU/scf. The median observed HV in SoCalGas service territory is 1034 BTU/scf.

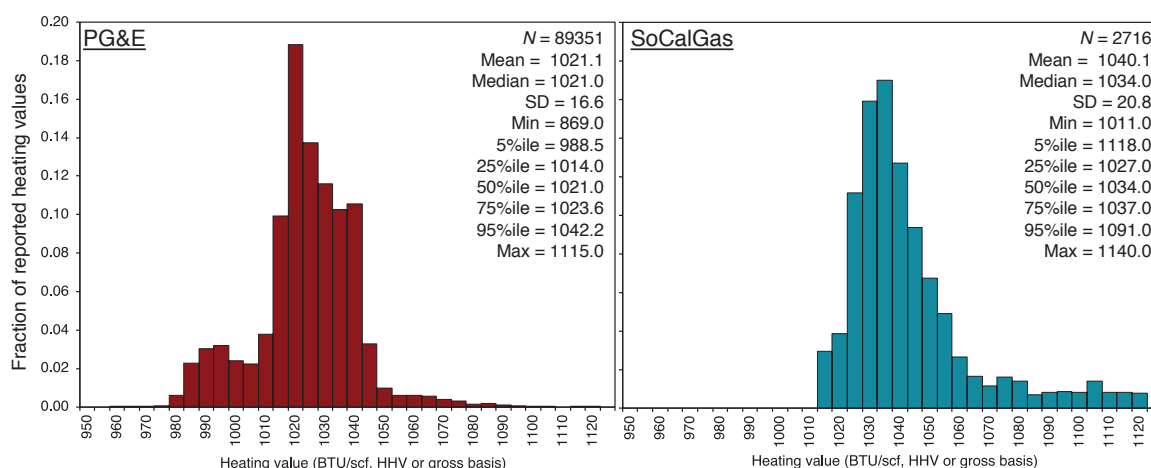


Figure 6. Historical HVs in PG&E BTU districts during the period November 2007 to November 2017 (Left). Distribution of HV in SoCalGas service territory during the period June 2012 to March 2017.

As discussed above, interchangeability indices such as Wobbe are more useful for ensuring safe operation of combustion equipment. Estimates of historical Wobbe can be made based on the best available data. Based on reported historical PG&E HV and specific gravity (SG), the median historical Wobbe delivered is 1339 BTU/scf. SoCalGas reported a median historical Wobbe delivered of 1332 BTU/scf (CPUC, 2006). The CPUC used this to set interchangeability guidelines for acceptable Wobbe with a safe range defined between 1279 to 1385 BTU/scf.

There remains uncertainty regarding the degree to which all grid-tied combustion equipment will be properly tuned to receive the historical median gas quality. Anytime an appliance is adjusted, it is being tuned to the gas delivered at that particular time, and studies have shown significant variation in the proper tuning of combustion appliances within utility service territories (D’Zurko & Benson, 2015). However, on average, utilizing the median historical Wobbe and HV as benchmarks for baseline gas quality delivered is likely a reasonable assumption.

4.4 Quantitative assessment of three representative HV specifications

In order to perform quantitative integration of the above evidence, we will examine three representative HV specifications. These representative HV specifications should be considered illustrative and do not represent recommendations.

The three representative HV specifications which were assessed are:

- 990 BTU/scf – the current Rule 30 in Southern California
- 970 BTU/scf – most common North American HV specification
- 950 BTU/scf – lowest observed current North American HV specification

4.4.1 Impact on required gas purity

For simple binary mixtures of CH_4 plus inert species (a reasonable assumption for biomethane), the HV of biomethane is a nearly linear function of percent total inert species (see Figure 7. Heating value of biogas mixtures as a function of the percent of CH_4 in a mixture of CH_4 and CO_2 (black solid line) using ideal gas behavior at 14.73 psia and 60 °F. Analyzed HV specifications of 950, 970, and 990 BTU/scf are shown in green, orange, and red dashed lines.). As CH_4 has an HV of 1014.4 BTU/scf, a minimum HV of 990 BTU/scf requires ~98% CH_4 . An HV of 970 and 950 BTU/scf corresponds to ~96% and ~94%, CH_4 , respectively. All calculations use the ideal gas HV for CH_4 at 14.73 psia and 60 °F (~1012 BTU/scf) corrected for real gas behavior using the Gas Processing Association (GPA) double summation method (1014.4 BTU/scf).

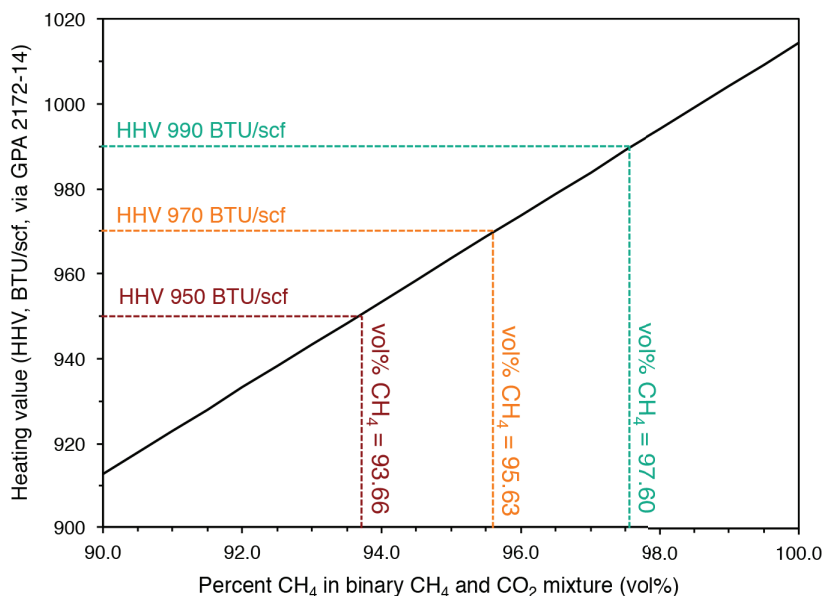


Figure 7. Heating value of biogas mixtures as a function of the percent of CH_4 in a mixture of CH_4 and CO_2 (black solid line) using ideal gas behavior at 14.73 psia and 60 °F. Analyzed HV specifications of 950, 970, and 990 BTU/scf are shown in green, orange, and red dashed lines.

4.4.2 Interaction with existing equipment base

As California had a minimum HV specification of 970 BTU/scf from the 1970s until 2006, it is likely that many existing appliances and equipment are operable with a HV of 970 BTU/scf. Also, because HV specifications ~ 970 BTU/scf are very common in North America, consumer appliances are likely designed to operate well for 970 BTU/scf. Conversely, given the relatively less common HV specifications near 950 BTU/scf, less favorable interaction with the existing equipment base is possible.

Finding: California allowed a lower HV of 970 BTU/scf before 2006.

Finding: Other states have lower minimum HV, as low as 950 BTU/scf. The most common minimum HV requirement in the United States is approximately 970 BTU/scf.

Interchangeability indices like Wobbe account for combustion-related concerns associated with changing gas composition. However, even in cases where the interchangeability indices are within accepted ranges for proper combustion, concerns can still arise with low Wobbe gases. For example, low Wobbe gases combusted in timed equipment could result in undercooked food or out-of-specification manufactured product.

Table 6. Interchangeability studies from empirical literature (n.d. = no data). This table only includes studies that examined lower bounds on HV. above displays that SoCalGas (2011) found undercooked beef patties at a HV of 960 BTU/scf. More recently, Hernandez et al. (2017) found no statistical difference between cooked food temperatures when using a gas of 974 BTU/scf compared to a baseline gas of 1150 BTU/scf, the Rule 30 maximum HV specification. These limited pieces of evidence suggest that the representative HV specification of 970 BTU/scf is not likely to lead to food safety concerns, while the representative HV specification of 950 BTU/scf could result in undercooked food if used in un-adjusted timed cooking equipment.

4.4.3 Interaction with other intersecting gas quality specifications

Other regulations — such as minimum Wobbe, maximum total inerts, or maximum CO_2 — result in various implications for biomethane composition. In order to illustrate these impacts, these regulatory bounds were modeled for biomethane as a ternary mixture of CH_4 , CO_2 , and N_2 . While O_2 is a non-trivial component to consider when upgrading biogas to produce biomethane, the regulatory bounds in Rule 21 and Rule 30 are 0.1 and 0.2 vol.% O_2 , respectively. At these volumes, the O_2 content will have a negligible effect on the HV of the gas.

Figure 8 plots the potential biomethane compositions which would meet each of these specifications, with vol.% CO_2 on the x-axis, and vol.% N_2 on the y-axis. For a ternary mixture, the vol.% CH_4 is the balance to 1.

The maximum CO₂ constraint imposes a vertical line at the regulated bound (3% for Rule 30, 1% for Rule 21). The maximum total inerts on the Rule 30 figure is a diagonal line running from the point at 4% N₂, 0% CO₂, to the point at 0% N₂, 4% CO₂.

The interchangeability guidelines in Rule 30 mandate a minimum Wobbe of 1279 BTU/scf. This constraint was calculated by using the equation for the Wobbe Number as a function of HV) and specific gravity.

$$\text{Wobbe Number} = \frac{HV}{\sqrt{SG}}$$

For a ternary mixture of N₂, CO₂, and CH₄, the only component contributing to the HV will be the vol.% CH₄ (x_{CH_4}). The SG of the gaseous mixture will be a volume-weighted fraction of each component's SG. Thus, the cutoff for minimum Wobbe is defined as:

$$1279 = \frac{x_{CH_4} HV_{CH_4}}{\sqrt{x_{N_2} SG_{N_2} + x_{CH_4} SG_{CH_4} + x_{CO_2} SG_{CO_2}}}$$

This calculation produces a binding minimum HV of between 968 and 980 BTU/scf, depending on if the biomethane is a binary mix of CH₄ and N₂ or CO₂, respectively. In addition to the Wobbe specifications present in Rule 30, both Rule 21 and Rule 30 ensure gas interchangeability through the AGA Interchangeability indices discussed above.

Using the AGA Bulletin 36 interchangeability indices, the authors analyzed acceptable biomethane composition without breaching the lifting limit imposed by Rule 30 and Rule 21, which is a maximum lifting index of 1.06 (SoCalGas, 2015, p. 18). The AGA lifting index constraint was calculated by finding the point in the ternary mixture with the minimum CH₄ content that could still meet a maximum flame lifting index of 1.06. In order to apply the AGA flame lifting index, median historical Wobbe and HV information must be converted into a baseline gaseous composition. The below compositions (see Table 7. Representative baseline gas compositions for Rule 21 and Rule 30 historical median gas quality.) were designed to match historical reported HV and Wobbe for the Rule 30 and Rule 21 regions of California.

Table 7. Representative baseline gas compositions for Rule 21 and Rule 30 historical median gas quality.

Region	Component (vol.%)					HV (BTU/scf)	SG	WN (BTU/scf)
	CH ₄	C ₂ H ₆	O ₂	CO ₂	N ₂			
Rule 21	94.9	3.27	0	0.76	1.05	1021	0.5824	1337.9
Rule 30	91.2	6.13	0	1.25	1.42	1034	0.6026	1332.0

In order to identify the most restrictive bound which the AGA lifting limit could place on HV, we find the maximum vol.% CH₄ at which the lifting limit could possibly be breached. As CO₂ is a heavier molecule than any of the other inert components that may be present in biomethane, the worst-case scenario for flame lifting would be if the biomethane were a binary mixture of CH₄ and CO₂. This will create the highest lifting index for a given vol.% CH₄.

For these worst-case scenarios, it was determined that in order to abide by the maximum lifting index of 1.06, the vol.% CH₄ must remain above ~96.5% for both Rule 21 and Rule 30 regions. These resultant binding compositions for Rule 21 and Rule 30 yield biomethane with HV of nearly 980 BTU/scf and Wobbe Numbers just under 1280 BTU/scf. These results indicate that the AGA lifting index constraint is less binding than the current minimum HV specification and aligns well with the current minimum Wobbe specification present in Rule 30.

Finally, the representative minimum HV constraints were imposed as lines encompassing all composition points with the required minimum vol.% CH₄ to meet the minimum HV, as explained above. Figure 8. The regulatory constraints on acceptable biomethane composition are visualized as prescribed by Rule 30 (left) and Rule 21 (right) under current conditions with a minimum HV of 990 BTU/scf (A, B), with a minimum HV of 970 BTU/scf (C, D), and with a minimum HV of 950 BTU/scf (E, F). shows the feasible region (white) and infeasible region (red) for the three representative minimum HV specifications: 990 BTU/scf (top), 970 BTU/scf (middle), and 950 BTU/scf (bottom).

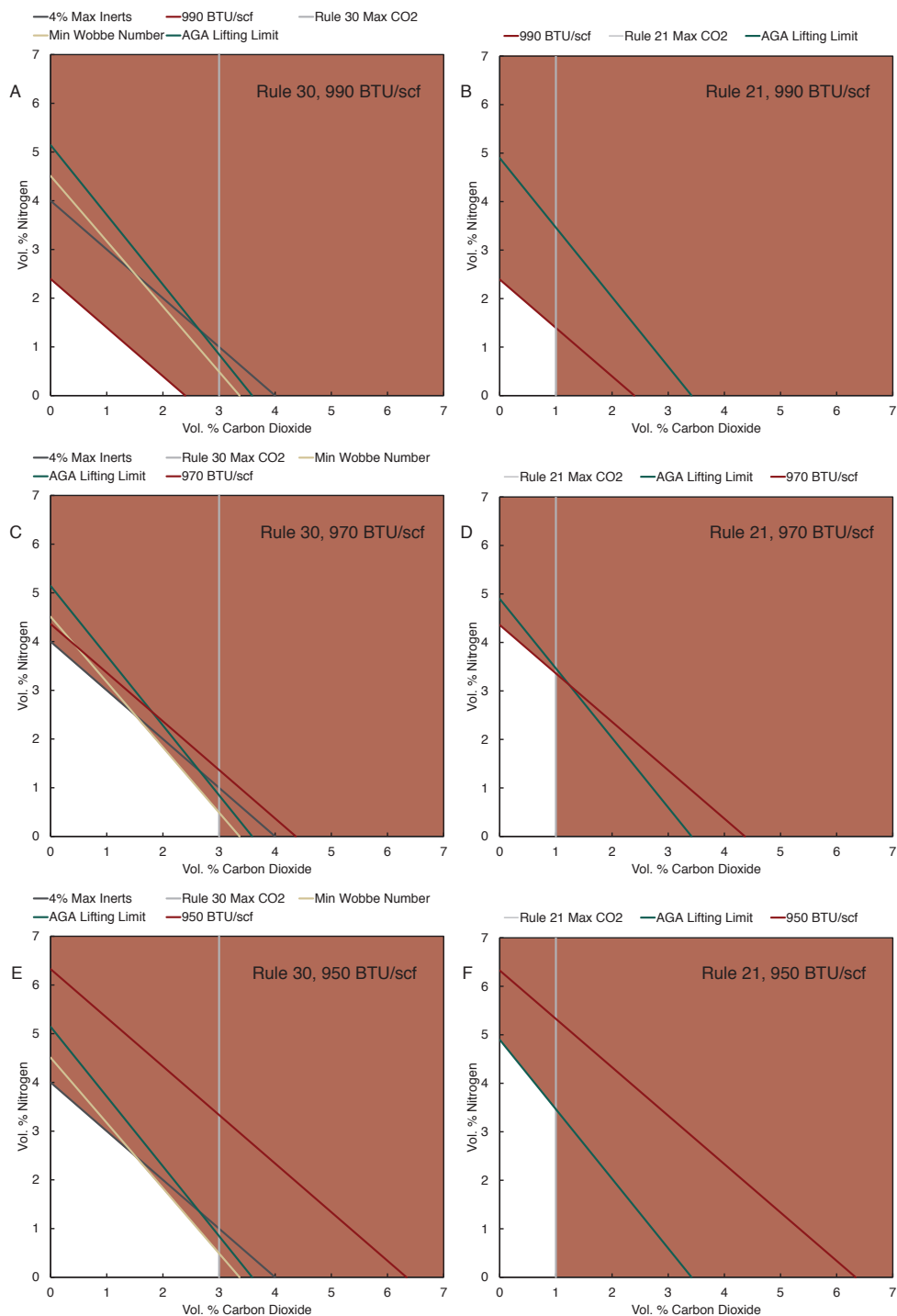


Figure 8. The regulatory constraints on acceptable biomethane composition are visualized as prescribed by Rule 30 (left) and Rule 21 (right) under current conditions with a minimum HV of 990 BTU/scf (A, B), with a minimum HV of 970 BTU/scf (C, D), and with a minimum HV of 950 BTU/scf (E, F).

For the current minimum HV specification of 990 BTU/scf (top, panels A and B), the minimum HV is the most constraining specification on the composition of biomethane for Rule 30 regions, while a mixture of maximum CO₂ specifications and historical HV are binding for the case of Rule 21 regions.

In the moderate HV specification case of 970 BTU/scf (middle, panels C and D), the constraining specification changes. For Rule 30 regions, there are some compositions where the Wobbe is the most constraining specification and there are others that could exceed the maximum 4% inerts specification before breaching the minimum Wobbe. For Rule 21 regions, additional high N₂ compositions become feasible, but the maximum 1% CO₂ specification limits feasibility for a number of compositions. Under Rule 30 specifications, biomethane with a HV of exactly 970 BTU/scf will not be able to meet all other existing gas quality specifications, while in Rule 21 specifications, high N₂ blends at exactly 970 BTU/scf can satisfy all other requirements.

Under Rule 30, no additional feasible compositions are available in our low HV specification case of 950 BTU/scf (bottom, panels E and F), as other specifications constrain the composition. In Rule 21 regions, there is greater latitude due to the absence of a stated minimum Wobbe Number; however, the maximum AGA lifting index will constrain the composition before any operational hazards are expected to arise.

A notable result is the commonly binding limitation of 1% maximum CO₂ in Rule 21 regions. This maximum CO₂ content is quite stringent compared to the distribution of reported CO₂ limitations in the AGA survey of gas quality specifications (see).

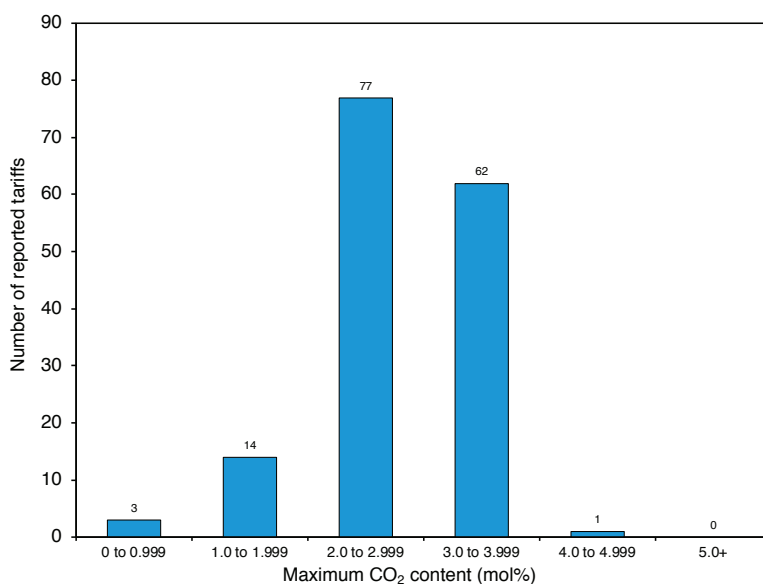


Figure 9. Distribution of reported maximum CO₂ specification across 224 publicly available tariffs from U.S. and Canada (AGA, 2009).

In summary, for both Rule 30 and Rule 21 regions, there is a significant compositional region in which the HV specification could be relaxed while maintaining the remainder of the gas quality specifications.

In the Rule 30 region, the relaxation of the minimum HV specification to the range of 970 BTU/scf will allow for the interchangeability and inert gas specifications to act as the binding constraints on biomethane composition. In the Rule 21 region, relaxation will allow a larger range of N₂-rich compositions while ensuring the AGA lifting limit is maintained. However, as Rule 21 regulates HV and interchangeability on a case-by-case basis, there may be regions where delivering gas with a HV near 970 BTU/scf may exceed the AGA lifting index limit. Allowing for a lower HV in biomethane could allow for more economical production of biomethane while still maintaining the interchangeability index guidelines, ensuring safe operation of combustion equipment. Relaxing the Rule 21 CO₂ specification would allow for even more possible compositions at or near 970 BTU/scf minimum HV specification and should be examined in more detail.

4.5 Summary of upgrading methods

There are many technologies for upgrading biogas to biomethane and increasing the HV. The most common method to increase the HV is by removing inert constituents. Reviews in the literature cover these technologies in great detail (Bauer, Hulteberg, Persson, & Tamm, 2013a; Hagen & Polman, 2001; Ong, Williams, & Kaffka, 2014; Persson, 2003; Ryckebosch, Drouillon, & Vervaeren, 2011; Sun et al., 2015). The most common biogas upgrading methods include membrane separation, pressure swing adsorption, amine scrubbing, and water scrubbing.

4.5.1 Removal of inert components

Selective membranes can be used to separate CH₄ from CO₂ and other inert components. Membrane separators are reliable and simple, but several stages are often needed to achieve high CH₄ purity (Ryckebosch et al., 2011)hydrogen sulfide, siloxanes, hydrocarbons, ammonia, oxygen, carbon monoxide and nitrogen. In order to transfer biogas into biomethane, two major steps are performed: (1. Pressure Swing Adsorption (PSA) is a method that utilizes zeolites or activated carbon to adsorb CO₂ and other inert components from a gaseous mixture. During pressurization, the CO₂, N₂, and O₂ preferentially adsorb to the matrix, and the CH₄-rich product gas is expelled from the vessel. In a purge cycle, the pressure is then reduced to desorb inert gases, which are then rejected. Amine absorption and water scrubbing are methods for CO₂ removal that leverage the preferential solubility of CO₂ in either an amine solvent or water. Amine scrubbing can achieve CO₂ removal efficiencies greater than 99.5% (Hagen & Polman, 2001; Ryckebosch et al., 2011)hydrogen sulfide, siloxanes, hydrocarbons, ammonia, oxygen, carbon monoxide and nitrogen. In order to transfer biogas into biomethane, two major steps are performed: (1. In the case of biomethane, the resultant CH₄ purity will be impacted by the presence of O₂ and N₂ in the raw biogas, which are not removed by amine or water scrubbing. These upgrading methods are discussed further in Appendix D.

4.5.2 Addition of higher HV components

In addition to removal of inert gases, HV specifications could be met by blending biomethane with higher molecular weight hydrocarbons such as propane (C_3H_8). While this cannot serve as a substitute for one of the above upgrading methods due to inerts limits, addition of propane can supplement the HV of the product gas to reach the minimum HV specification once other gas quality specifications are achieved. Propane has a real gas HV of approximately 2566 BTU/scf (at 14.696 psia and 60 °F). Blending requirements can be tested using a binary mixture of CH_4 and CO_2 . If the binary CH_4 - CO_2 mixture is upgraded to meet the maximum inerts specification of 4%, with an HV of ~973 BTU/scf, approximately 1.05 vol.% C_3H_8 will need to be blended to meet 990 BTU/scf. If, on the other hand, the gas is further cleaned to meet the minimum Wobbe of 1279 BTU/scf, approximately 0.63 vol.% C_3H_8 would need to be blended to reach 990 BTU/scf.

Similarly, it has been proposed that biomethane producers can ensure they meet specifications by mixing their product gas with NG flowing in the nearest pipeline. Such active blending could be applied in places where the local flow of NG is sufficient to allow a well-mixed combination of biomethane and NG to meet the minimum gas quality specifications (see further discussion of dilution in Chapter 6).

4.6 Synthesizing conclusions and recommendations

Available evidence suggests that a reduction of the minimum HV specification to levels near the representative 970 BTU/scf HV specification would be acceptable from both safety and equipment durability perspectives. Arguments supporting the feasibility of a minimum HV specification of 970 BTU/scf include:

1. The current minimum HV specification was established in 2006, and previously the minimum HV specification was 970 BTU/scf. There is precedent for lowering the minimum HV specification in order to accommodate a new energy resource.
2. Most interchangeability hazards are phenomena governed by the maximum Wobbe limit or a maximum HV limit. Therefore, when considering biomethane interchangeability, the set of risks is limited to flame lifting and potential blowout, as biomethane will have a characteristically lower Wobbe than the typical gas historically received.
3. While it is typical to specify a minimum HV specification, it is not particularly important for ensuring safe operation. A more relevant metric would be directly related to gaseous fuel interchangeability, such as the Wobbe Number. Therefore, if a minimum HV specification is to be instituted, there is no reason for it to be more stringent than the comparative minimum Wobbe Number specification.

4. The literature provides several empirical examples in which appliances exhibit no safety or operational issues when switching from baseline gases (with higher HV and Wobbe characteristics) to a fuel with an HV of ~ 970 BTU/scf and a Wobbe of ~ 1279 BTU/scf.
5. The current minimum HV specification is the most restrictive specification on acceptable biomethane composition. Relaxing the minimum HV specification to a level near 970 BTU/scf would allow for a greater range of biomethane compositions, while minimum Wobbe and maximum inerts specifications will still ensure interchangeable operations. To be clear, under the Rule 30 specifications, biomethane with a HV of exactly 970 BTU/scf will not be able to meet all other existing gas quality specifications. The relaxation to a level near 970 BTU/scf would allow more appropriate specifications (i.e., Wobbe, inerts) to act as the bounds on composition, ensuring safe utilization. Furthermore, as Rule 21 regulates HV and interchangeability on a case-by-case basis, there may be regions where delivering gas with a HV near 970 BTU/scf violates the AGA lifting index.

Evidence does not support reduction of minimum HV specification to a level near 950 BTU/scf without further study. Challenges with HV specifications near 950 BTU/scf include:

- Lack of recent empirical interchangeability studies at this lower HV level
- Unclear impacts on corrosion-related safety issues if maximum CO_2 specifications are loosened to accommodate gas with a lower HV
- Unclear interaction with the existing California appliance and equipment base
- Unclear prevalence of timed cooking equipment that might cause undercooked food if unadjusted

Given that some regions (Texas, Midwest) have minimum HV specifications of 950 BTU/scf, these challenges are not likely to be insurmountable. We advise further experimental study, as well as consultation with utilities and regulators in those regions, before lowering the HV specification to levels near 950 BTU/scf.

Conclusion 1: The scientific modeling by authors of this paper and in the literature provides evidence that keeping the current minimum WN and relaxing the HV specification to a level near 970 is unlikely to impact safety or equipment reliability.

Conclusion 2: The admittedly incomplete available evidence suggests that relaxing the HV specification to a level near 950 could affect safety.

Recommendation 1: Keep the WN minimum requirements as they are now.

Recommendation 2: Reexamine regulations on heating value (HV) minimum levels. Initiate a regulatory proceeding to examine the option of allowing biomethane satisfying the current WN limits and all other requirements, but with a HV as low as 970 BTU/scf.

For future increases in flexibility of the gas grid, grid-tied appliances could be engineered to be able to tolerate a wider range of gaseous fuel compositions (Jones, 1989). These flex-fuel appliances might have an oxygen sensor in the exhaust stream and automatically adjust air flow to ensure proper combustion. If the long-term objective is to migrate towards a decarbonized pipeline that leverages a wider spectrum of gaseous energy resources, biomethane included, then one long-term trend should be improved flexibility at the burner tip. Non-combustion uses of natural gas would also need to be evaluated for their ability to withstand fluctuations in gaseous fuel composition.

Chapter 5

Assessment of evidence for the current California siloxane specification

Key points

- Experimental evidence on impacts of siloxanes on end-use equipment is limited, with only a small number of experiments conducted on a small sample size of combustion devices.
- Combustion of siloxanes, even at very low concentrations, causes silica deposition that can damage equipment in many ways, ranging from deactivation of key sensors to clogging of narrow tubes and fouling of catalyst beds and fuel cell electrodes.
- The potential human health impacts of inhalation exposure to amorphous silica nanoparticles produced by the combustion of siloxane-containing fuel are unclear at this time.
- The current maximum siloxane specification is based on a small amount of data and involves significant extrapolation.
- There are more than 50 active biomethane projects at North American landfills and wastewater treatment plants, 48 of which are adding biomethane to a NG pipeline without a siloxane specification in place. This provides evidence that siloxanes can be removed, presumably, to adequate levels that ensure system safety.
- There is currently no scientific consensus on a method for reliable measurement of volatile silicon-containing compounds in a gaseous fuel. While there are laboratories that currently claim to provide the required level of precision to satisfy the California utilities, there remains uncertainty among the developers and financiers of biomethane projects. This uncertainty will diminish greatly as the ASTM International process for standardization of methods is completed.
- Given the above uncertainties, we cannot recommend loosening or tightening the siloxane specification without significant further experimental work and/or more systematic data collection on existing projects in operation.
- We recommend a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes, together

with monitoring of the ASTM International process to adopt and test a standard method for measurement of siloxanes.

5.1 Empirical experiments of impacts of siloxanes on combustion appliances

A small number of studies have conducted controlled experiments on end-use equipment operated with siloxane-containing fuel. As residential appliances are those that often go the longest periods without receiving service or inspection, they are often characterized as the most sensitive to contaminants such as siloxanes and have been the most widely studied in the public literature. The results of these studies are summarized in Table 8. Summary of experimental literature regarding siloxane fouling of combustion appliances.. Appendix B contains more detailed descriptions of these studies.

Table 8. Summary of experimental literature regarding siloxane fouling of combustion appliances.

Source	Equipment	Siloxane Content	Comments
DNV KEMA Energy & Sustainability (Gersen, 2013)	Residential boiler	13.8 mg Si/m ³	Ionization probe failed in all experiments.
	Residential water heater	121 mg Si/m ³	Narrow-tube heat exchangers clogged, reducing air flow, and increasing CO emissions
University of Southern California/SoCalGas (Nair et al., 2012, 2013)	Honda EU200i electric generator	43 mg Si/m ³	Oxygen sensors failed a performance test after 40 hours in operation at 43 mg Si/m ³ . Catalyst bed was deactivated by 94.4% after 400 hours in operation.
	Residential furnace	86, 43, 8.6 mg Si/m ³	Flame sensor failed after 70 hours of operation at 8.6 mg Si/m ³ , after 30 hours of operation at 43 mg Si/m ³ , and after 40 hours of operation at 86 mg Si/m ³ .
GTI Assessment of Acceptable Siloxane Concentration (Bora, Crippen, & Ferrer, 2013)	Vented water heater (Kenmore Model 33637)	8-14 mg Si/m ³	Significant silica deposition on internal surfaces. Operational throughout the testing period (7428 hours of run time, simulating almost 5 years). No changes to CO emissions.
	Unvented oven (Kenmore Model 7040)	8-14 mg Si/m ₃	Ignitor coil began to sporadically fail after 6890 hrs (simulating 75 months) of operation. Complete failure occurred at 7440 hrs (simulating 81 months) of operation. No significant changes to CO levels.
National Grid UK (Network Innovation Allowance Project Status Report, 2017)	Fully premixed boilers	6.3, 2.8, 1.5 mg Si/m ³	Failure of ionization probe occurred at 1.5 mg Si/m ³ after 2464 hours (4090 m ³ of NG usage). Siphon clogged when tested at 3 mg Si/m ³ , but no failure was observed at 1.5 mg Si/m ³ . After 4135 hours of using 1.5 mg Si/m ³ , heat input reduced by 28%. Recommended a maximum silicon concentration of 0.23 mg Si/m ³ .
	Hot water heater	6.3, 2.8, 1.5 mg Si/m ³	Significant increase in CO emissions due to decreased air intake.

The USC (2013) experiments, funded by SoCalGas, on the residential furnace serve as the scientific basis for the current maximum siloxane specification in California. The experimental time to failure used was 70 hours at 8.6 mg Si/m³. From this, extrapolation to a lifetime of 15 years was performed assuming three hours/day, seven days/week, and 16 weeks/year, or 5040 operating hours. Scaling 8.6 mg Si/m³ by the ratio of 70/5040 gives an allowable concentration of approximately 0.1 mg Si/m³. This extrapolation implicitly assumes linear deposition as a function of concentration (see below) and that the effects of this deposition will also scale linearly over long time-scales.

Silica deposition causes device damage in multiple ways, including: heat exchanger clogging, ionization probe or flame sensor failure, oxygen sensor failure, ignitor coil failure, and catalyst deactivation. For addressing safety concerns, it is paramount to understand the frequency of different kinds of failures.

The mode of damage or failure is important to determining the safety impacts of siloxanes. Some damage modes will result in immediate non-operation of the device due to fail-safe features installed on most appliances. For example, the failure of a flame sensor will shut off gas to the burner tip and prevent device operation. This would result in the device owner calling maintenance personnel who will address the issue and replace the damaged sensor. In contrast, a degradation mode that increases CO emissions due to airflow restriction could go unnoticed without nearby CO monitoring, leading to possible safety concerns (Gersen, 2013).

The current experimental literature does not contain enough data points to characterize failure frequency as a function of siloxane concentration.

5.2 Scientific literature on depositional modeling

The Det Norske Veritas (DNV) KEMA study (Gersen et al., 2013) shows that decreasing the concentration of siloxanes in the fuel gas will lead to a decreased thermal output reduction, per unit of silica produced. This nonlinear relationship between thermal output reduction and siloxane concentration can be explained by the increasing density of the silica layer that is deposited as the concentration decreases. In Figure 10. Illustration of silica deposition density as a function of concentration. Greater concentrations of silica particles (left) will cause a less dense deposition layer, while a lower concentration (right) will result in a layer resembling the bulk density. In the left panel, we see that the silica particles agglomerate into larger, oddly shaped pieces before deposition, resulting in voids and lower deposited bulk silica. In the right panel, with lower siloxane concentration, the silica particles remain small and are uniformly deposited on the surface. This nonlinear relationship between siloxane concentration and time to failure, or thermal output reduction, makes reliable extrapolation to lower concentrations difficult (Gersen et al., 2013). However, the experimental study of the density silica layers deposited at the lowest concentration tested shows that the density is nearly that of bulk silica. Therefore, the researchers extrapolated

linearly from that point toward lower concentration, as nonlinear density effects are eliminated at this point.

Silica deposition was also found to be driven primarily by thermophoresis, as the temperature gradient drives the silica to deposit as a solid on appliance surfaces (Gersen et al., 2013). Thermophoretic deposition and concentration-dependent deposition density are well-documented phenomena in general deposition literature (Altmann & Ripperger, 1997; Batchelor & Shen, 1985).

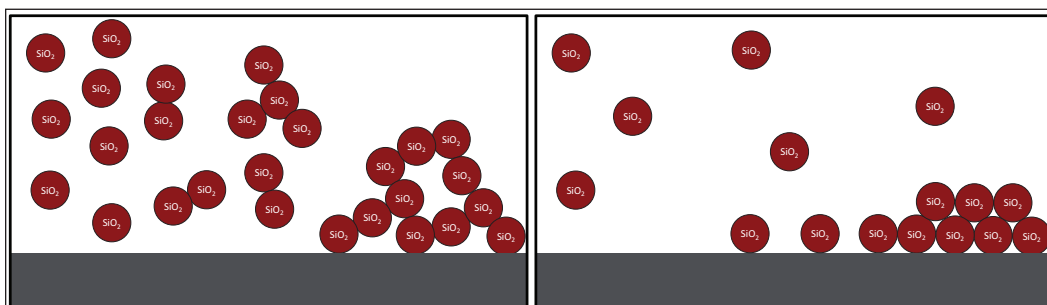


Figure 10. Illustration of silica deposition density as a function of concentration. Greater concentrations of silica particles (left) will cause a less dense deposition layer, while a lower concentration (right) will result in a layer resembling the bulk density.

Some work has been done in modeling the deposition of silica in the post-combustion area. Turkin et al. (2014) crafted a model of silica deposition which revealed that the deposition flux of silica depends linearly on siloxane concentration (Turkin et al., 2014). However, such modeling is challenging to interpret for real-world impacts because the effects of silica buildup are highly device specific. As displayed above, for some appliances with narrow tubes, clogging may be of legitimate concern, while buildup on the flame sensor will be the primary cause of failure in others. The effects of silica deposition in end-use equipment are highly dependent on device geometry and the specific set of components and sensors existing in a particular configuration. Therefore, theoretical deposition modeling is less helpful for understanding impacts on sets of grid-connected combustion equipment.

5.3 Review of operational experiences

There is a great deal of operational experience with siloxanes at biogas and biomethane projects in North America and Europe. The Coalition for Renewable Natural Gas maintains a database of all active biomethane projects in North America. The numbers of operating landfill and wastewater treatment plant projects are summarized in Table 9. Number of active biomethane projects from landfills

and wastewater treatment plants in the U.S. (listed as online)., with more than 50 total projects generating gas from landfills and WWTPs. A total of 49 of these operating projects inject gas into pipeline systems. Only one of these projects (Point Loma in San Diego) has been injecting while subject to a siloxane specification. The remainder are not subject to such specifications.

Table 9. Number of active biomethane projects from landfills and wastewater treatment plants in the U.S. (listed as online).

Source of biomethane	Number of projects	States where operational
Landfill, pipeline injected	41	-
CNG/LNG transportation fuel	31	AR, IL, KS, LA, MI, MS, NE, NY, OH, OK, PA, TN, TX, WA, WV
Electricity	3	GA, PA, TX
Heat/Electricity	2	TN, PA
Industrial	1	TX
Not specified/Other	4	KS, MI, MT, PA
Landfill, not pipeline injected	4	-
CNG/LNG transportation fuel	4	CA, IN, LA, MI
Landfill, injection status not listed	2	-
CNG/LNG transportation fuel	1	GA
Other	1	MI
WWTP, pipeline injected	5	-
CNG/LNG transportation fuel	3	CO, IA, KS
Electricity	1	CA
Heat/Electricity	1	OH
WWTP, not pipeline injected	1	-
CNG/LNG transportation fuel	1	CA
WWTP, injection status not listed	5	-
CNG/LNG transportation fuel	5	NE, OH, TX, WA, WI

No systematic survey of operational issues associated with these projects was found. Contact was attempted with listed systems operators, resulting in two successful communications. Duke Energy has been accepting 1.5 billion cubic feet (bcf) annually from Rumpke Sanitary Landfill for several decades, delivering this gas to a wide range of consumers. Because no systematic reporting of siloxane concentrations nor of maintenance issues (or lack thereof) is available from this case, it is unclear if this experience supports or refutes the numerical specifications. Personal communication with Duke Energy's Supervisor of System Integrity suggests that they are unaware of any problems arising from siloxanes.

Atmos Pipeline in Texas has been accepting a large amount of biomethane from McCommas Bluff landfill facility since 1999. A business development manager with Atmos provided signed testimony that since 1999 Atmos is unaware of any issues related to the delivery of biomethane to any of its downstream customers. The individual also confirmed that there

are customers within a mile of the injection site, and the gas has been received by industrial, commercial, and residential customers without incident.

No systematic reporting was found for cleanup equipment in place in landfill projects, pre- and post-treatment siloxane concentrations, or maintenance concerns in affected service area. The best available data on the concentrations of siloxanes at operational biomethane projects comes from a GTI investigation which examined 27 samples of post-treatment upgraded biomethane from seven different landfill sites (Crippen, Wiley, & Bora, 2012). Twenty-two of the 27 gas samples were below the reported detection limit (0.1 mg Si/m³ for each compound), and the remaining five samples reported between 0.1 and 0.4 mg Si/m³. Thus, these landfills were achieving results near to, but not verifiably in accordance with, the Rule 30 standard of 0.1 mg Si/m³ for total siloxanes.

This experience suggests currently operational biomethane projects are largely removing siloxanes such that biomethane can be used safely. However, it is challenging to use these experiences as evidence for or against any particular siloxane standard. The absence of observed problems does not refute the need for standards.

5.4 Review of combustion equipment manufacturer specifications

Some manufacturers of natural gas-fueled equipment have instituted specifications for maximum allowable siloxane concentration to ensure proper operation (see Table 10. Surveys of maximum siloxane concentration in end-use equipment. and Figure 11). Operators do not provide methodological details about how such specifications were developed (e.g., any testing data are proprietary). This information gap makes it difficult to use engine manufacturer specifications as a basis to place a limit on maximum allowable siloxane concentration for pipeline injection.

As shown in Figure 11, the current California specification of 0.1 mg Si/m³ is lower than most equipment specifications with the exception of one combustion turbine and all microturbines. In addition, some hypersensitive equipment (mainly fuel cells) are known to have activated carbon filters to polish the gas prior to use, even during regular NG service. No data were found on the proportion of NG equipment that will have such on-site gas polishing in place. However, the majority of residential and commercial appliances will likely be using NG as delivered.

The methods and data used to develop manufacturer standards are typically not available in public domain. As such, these are not useful for detailed modeling of potential impacts. However, any siloxane standard should consider manufacturer specifications. This does not imply that the siloxane specification need be lower than all manufacturer standards, as it may be more cost-effective to install gas polishing equipment on particularly sensitive equipment.

Table 10. Surveys of maximum siloxane concentration in end-use equipment.

End-Use Application	Manufacturer	Maximum siloxane conc. [mg Si/m ³] (evaluated as D4 for biomethane at 990 BTU/scf)	Source
Reciprocating Engine	Various	10 – 36	[1]
	Caterpillar	3.5	[3]
	Jenbacher	10	[2]
	Waukesha	9	[6]
	Deutz	5	[2]
Combustion Turbine	Unknown (without Recuperation)	10	[1]
	Unknown (with Recuperation)	5	[1]
	Solar Turbines	5-10	[8]
Micro-turbine	Unknown	0.6	[1]
	Ingersoll-Rand Microturbines	0.046	[2]
	Capstone Microturbines	0.023	[2] [4]
Stirling Engine	STM Power	1.96	[5]
Fuel Cell	Fuel Cell Energy	4.66	[5]
Vehicle Fuel	Cummins Various (recommended)	14	[1]
		0.1	[7]

[1] (Pierce, 2015)

[2] (Wheless & Pierce, 2004)

[3] (“Caterpillar G36000- G3300 Fuels,” n.d.)

[4] (“Application guide, Landfill/Digester Gas Use with the Capstone MicroTurbine,” 2004)

[5] (Lampe, 2006)

[6] (“Gaseous Fuel Specification for Waukesha Engines,” 2014)

[7] (Kramer, Ferrera, Kühne, Moreira, & Magnusson, 2015)

[8] Personal communication

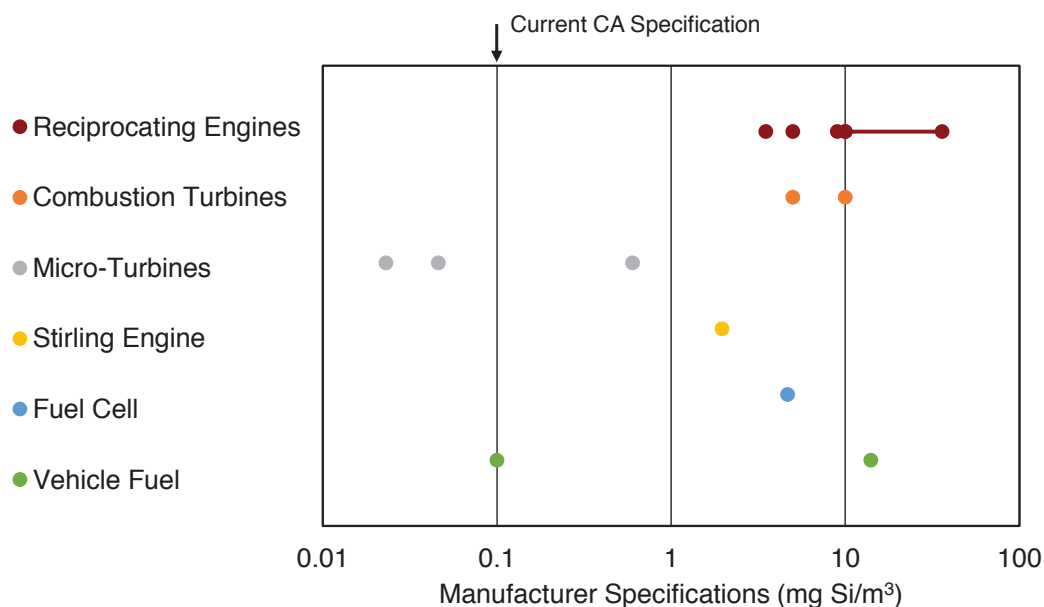


Figure 11. Survey of siloxane specifications reported by manufacturers of combustion equipment.

5.5 Review of siloxane presence and removal from biomethane

Siloxanes are manmade compounds, and there is no known biological process that forms them (Wheless & Pierce, 2004) oxygen and methyl groups. Siloxanes are used in the manufacture of personal hygiene, health care and industrial products. As a consequence of their widespread use, siloxanes are found in wastewater and in solid waste deposited in landfills. At wastewater treatment plants and landfills, low molecular weight siloxanes volatilize into digester gas and landfill gas. When this gas is combusted to generate power (such as in gas turbines, boilers or internal combustion engines. As such, siloxanes are not present in dairy waste, agriculture waste, and forestry residues. Some experimental work supports this: a Gas Technology Institute (GTI) study of dairy-derived biogas, which examined 42 samples of raw and cleaned biogas found no siloxane. (Saber, 2009b).

Finding: Siloxanes are not expected to be present in dairy waste, agriculture waste, or forestry residues.

Conclusion 5¹: Some sources are very unlikely to have siloxanes – e.g., dairies or agricultural waste. These sources could be held to a reduced and simplified verification regime to avoid unnecessarily encumbering sources that do not produce siloxanes.

Recommendation 5: Consider the development of a reduced and simplified verification regime for sources that are very unlikely to have siloxanes, such as dairies or agricultural waste.

There are a variety of siloxane removal technologies, and several thorough reviews have been published (Ajhar, Travesset, Yüce, & Melin, 2010; Dewil et al., 2006; Schweigkofler & Niessner, 2001; Soreanu et al., 2011). Most removal techniques aim to absorb or adsorb these compounds on media for removal via either disposal or thermal regeneration. The removal efficiency of these technologies often depends on how adequately the vessels are sized, how completely the media avoids short-circuiting, and how well breakthrough is monitored. Additionally, many siloxanes are also water-soluble and can be removed by cooling biomethane to a low enough temperature to condense much of the water into a liquid phase. A more thorough description of each method can be found in Appendix C.

Experimental studies find that siloxane removal technologies are effective at reducing siloxane concentrations. The experience of current biomethane projects in other states displays that several currently active landfill projects, not held to any siloxane specification, are already able to remove siloxanes below currently reported detection limits. A GTI report investigating landfill-derived biomethane examined 27 samples of post-treatment upgraded biomethane from seven different landfill sites (Crippen et al., 2012). Twenty-two of the 27 gas samples were below the reported detection limit (0.1 mg Si/m³ for each compound), and the remaining five samples contained between 0.1 and 0.4 mg Si/m³.

Finding: Siloxanes can be removed at relatively small cost before injections into pipelines, but possibly not to the current California standards.

The literature contains several sources of data on the presence of siloxanes in raw biogas and in processed biomethane from various sources (see Figure 12. Presence of siloxanes in raw biogas and biomethane derived from three major sources. Concentration is per species, not total Si.). The dotted lines indicate the various detection limits cited in the studies and lines running to zero indicate data-points were measured below the respective detection limit.

1. The conclusion and recommendation numbers here match those originated in the Summary Report for ease of referral. However, the flow of data and discussion here is not identical to the Summary Report discussion, resulting in Conclusion 5 and Recommendation 5 appearing out of order here.

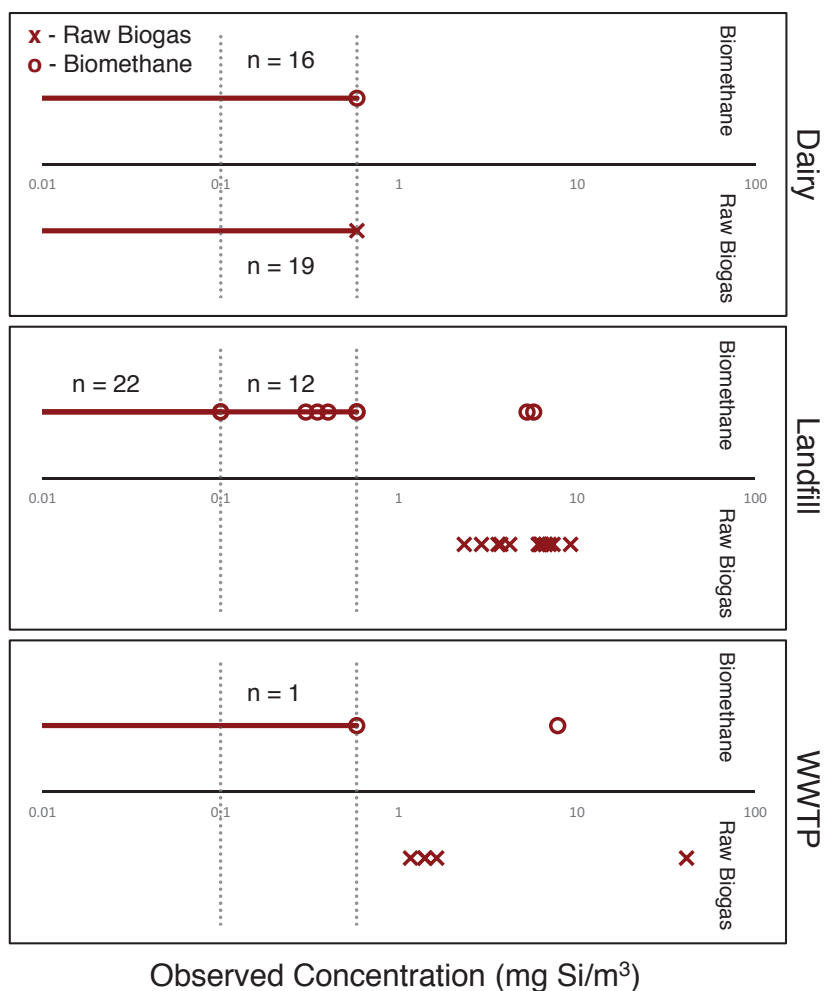


Figure 12. Presence of siloxanes in raw biogas and biomethane derived from three major sources. Concentration is per species, not total Si.

Another empirical example is the Point Loma Wastewater Treatment Plant. This WWTP has been injecting pipeline-quality biomethane abiding by Rule 30 specification of 0.1 mg Si/m³ for several years (“Turning Waste Into Renewable Natural Gas Point Loma Wastewater Treatment Plant Case Study—Five Years After Commercial Operation,” 2016). Personal communication with SoCalGas revealed that initially, Point Loma did not meet the siloxane specification. In response, another vessel of activated carbon was added to the process to polish the gas and remove any traces of siloxanes.

5.6 Review of potential human health impacts of siloxanes

A report prepared by the staff of CARB and OEHHA analyzed the health and safety implications of biomethane prior to combustion. However, the report did not examine post-

combustion products of the gas (CalEPA, 2013). If released prior to combustion, siloxane compounds were shown to have overall very low environmental or health impact. Siloxanes will be destroyed by hydroxyl (OH) radicals in a matter of days (Mokhov, 2011). However, post-combustion, the siloxanes form silica and agglomerate to form silica nanoparticles, which could potentially have detrimental health impacts.

A GTI assessment found via diffraction analysis that silica formed by combustion of siloxanes is amorphous in structure, not crystalline (Bora et al., 2013). The U.S. Department of Labor's Occupational Safety and Health Administration (OSHA) has published standards pertaining to mineral dusts ("Table Z-3 Mineral Dusts," 2016). OSHA standards regulate the maximum allowable time-averaged concentration of amorphous silica for an eight-hour shift at $80 \text{ mg SiO}_2/\text{m}^3$ divided by the percentage of the dust that is amorphous silica. Thus, for 100% amorphous silica, $0.8 \text{ mg SiO}_2/\text{m}^3$ is allowable (OSHA, 2016). No long-term amorphous silica exposure standard exists ("Table Z-3 Mineral Dusts," 2016).

Assuming a stoichiometric air ratio for combustion of natural gas, for every $1 \text{ mg Si}/\text{m}^3$ in the fuel (conservatively assumed to be $\sim 100\% \text{ CH}_4$), there will be $0.2 \text{ mg SiO}_2/\text{m}^3$ present in the combustion products. Therefore, at the levels considered in this work, the OSHA limit for eight-hour amorphous silica inhalation will not be exceeded even in pure combustion exhaust. Given that any inhaled exhaust will be highly diluted by surrounding air, siloxanes will not result in exceedance of OSHA-mandated eight-hour levels of amorphous silica exposure by mass.

In addition to the mass-based measure, OSHA specifies a maximum of 20 million particles per cubic foot (mppcf). Assuming a particle diameter of 100 nm, every $1 \text{ mg Si}/\text{m}^3$ will yield nearly 200 times the OSHA limit, approaching 4000 mppcf. After accounting for substantial deposition of particulate in the equipment and subsequent dilution of exhaust, it is unclear whether this standard will apply in the range of siloxane concentrations being considered.

It is not clear how relevant OSHA-derived standards are for products of biomethane combustion. Silica emerges from biomethane combustion processes in nano-particulate form. An experimental study conducted on a residential furnace used an air filter at the flue gas outlet to capture any particulate in the combustion products (Nair et al., 2013) such as the flame sensor, condenser coils, and tailpipes, and they also accumulated in the water that condensed on the furnace's flue vent. The coating of the flame sensor presented the key challenge for furnace operation because, after a certain period of exposure to the siloxanes, it was no longer able to sense the flame, thus causing the furnace to stop operating. In addition, a fraction of the silica particles of submicrometer size became entrained in and escaped through the flue gas exiting the furnace. The results of this investigation point out the critical importance of adequately removing these siloxane impurities from NG prior to its use.

A residential pulse-combustion furnace operating on natural gas (NG). The study found almost all of the silica particulate formed falls below 200 nm in diameter, with the mean concentration around 70 nm. Another study found silica particles of 40–70 nm in diameter formed from combustion of biomethane (Tansel & Surita, 2014). In general, we

should expect the size distribution of silica nanoparticles could range from 5 to 200 nm depending on how much agglomeration takes place before cooling.

Therefore, the focus of any human health concern will be on the impact of amorphous silica nanoparticulate and the potential toxicity associated with these particles. In general, particles of this size class are classified as carcinogenic, mutagenic, asthmogenic, or reproductive (CMAR) toxic nanoparticles and can be biologically active due to their large surface area to volume ratio.

The toxicity of nanoparticles in general has been shown to be size-dependent: smaller particles are more cytotoxic as the larger specific area can make these particles more apt to interact at the cellular level (Tansel & Surita, 2014; Wang et al., 2009). A comprehensive review of the properties of nano-sized silica materials, with specific emphasis on inhalation exposure, found a limited number of in vivo studies displayed largely reversible lung inflammation, granuloma formation, and focal emphysema, with no progressive lung fibrosis (Napierska, Thomassen, Lison, Martens, & Hoet, 2010). Most in vitro studies reported cellular uptake and size- and dose-dependent cytotoxicity (Napierska et al., 2010). However, very little is known about the health effects of silica nanoparticles, and combustion of NG is also known to release nanoparticles (Minutólo et al., 2010). As such, there is insufficient evidence to assign any human health impacts to the silica nanoparticles produced from combustion of siloxane-containing fuels.

Finding: During combustion, siloxanes are fully oxidized and form silica molecules. Deposition of silica on equipment can cause a wide variety of operational issues and hazards. Possible direct health impacts are not well known and need more study.

5.7 Review of methods of measuring siloxanes

For a specification to be effective, it must be able to be verified in a repeatable manner through a standardized measurement protocol. Some industry observers believe the current siloxane specification is set below the detection limits of current analytical technology, making it impossible to achieve reliable test results definitively showing that the gas product meets the specification of 0.1 mg Si/m³ (CRNG, 2016). The utilities, in comments to the CPUC, justify the maximum specification “based on review of engine manufacturer limits on siloxane in biogas and the detection limit of an on-line siloxane analyzer from approximately three years ago” (Decision 14-01-034 finalized in 2014). At present, no standardized measurement protocol exists, although a multi-year process to develop standard siloxane measurement methods is underway under the auspices of ASTM International (ASTMWK52796, 2018) (see below).

There are three main techniques for sampling siloxanes in biomethane for subsequent analysis: whole air sampling, impingers, and sorbents. Whole air sampling extracts a full sample of the gas. Whole air sampling is fast, low-cost, and requires less stringent training of sampling technicians. However, sample bags with silicon-based seals or adhesives can

cause false readings, and heavier siloxanes can adsorb onto the walls of bags and canisters, distorting results (Hayes, Graening, Saeed, & Kao, n.d.). Impingers collect siloxanes by drawing gas through a solvent-filled contact chamber, absorbing siloxanes for subsequent analysis. By metering flow rates through the impinger, the concentration in the gas can be inferred from concentration in the solvent. Solid sorbents absorb siloxanes onto media for further analysis. Impingers were found to recover a greater fraction of the siloxanes, but take a long time to complete in the field and are difficult to properly administer (Schweigkofler & Niessner, 1999).

Multiple analytical methods can be used to measure concentration (Hayes et al., n.d.). These methods generally consist of a gas chromatograph coupled with a flame ionization detector (FID), an atomic emission detector (AED), or a mass spectrometer. The FID is the least selective for siloxanes as it will detect any carbon-containing molecule and therefore can result in false positive identification. The AED is more selective for molecules containing Si atoms. Lastly, the mass spectrometer offers similar selectivity as the AED at a lower cost.

The precision and accuracy of each technology can vary. Air Toxics Ltd. (Hayes et al., n.d.) examined six biogas samples taken from the Sacramento Regional WWTP facility and analyzed them at three different laboratories by various analytical methods. The results displayed a large degree of variability and limited consensus regarding the amount of total silicon in the sample, with results ranging from 15.4 to 74.5 mg Si/m³ (evaluated as D4; originally reported as 3.3 to 16 ppm_v). Note that these test results were for raw biogas, which is known to be more difficult to analyze due to complex mixtures of many species.

At present, California utilities maintain that the current siloxane specification is a detectable level. SoCalGas provided the authors with redacted laboratory reports confirming the lab they utilize offers a reporting limit of 0.004 mg Si/m³ for each species. However, without a standardized test method (e.g. ASTM), it is unclear how representative or reproducible these results are.

Unison Solutions offers biomethane testing services with a detection limit of 5 ppb, which converts to between 0.01 to 0.03 mg Si/m³ depending on the compound. ALS Global claims to achieve reliable measurement of total siloxane levels below the 0.1 mg Si/m³ specification in repeated measurements and has provided this service for multiple California utilities. Finally, in all of GTI's published work, the detection limit is either specified as 0.58 mg Si/m³ (originally reported as 0.5 ppm_v) or 0.1 mg Si/m³ for each species (Crippen et al., 2012; Saber, 2009a). However, many biomethane project developers still believe there is significant financial risk of shut-in and lost revenues due to siloxane measurement error. The disconnect may be addressed by developing a standard method for measuring siloxanes.

Finding: At present, no standardized measurement protocol exists for dependable measurement for the specification of 0.1 mg Si/m³. Several testing laboratories claim detection limits of 0.1 mg Si/m³ or lower. However, we have not been able to independently test these claims.

Conclusion 3: Current California siloxane specifications are based on very little data and involve broad extrapolation from that data.

Conclusion 4: There is not enough information available now to determine whether 0.1 mg Si/m³ is too stringent or not stringent enough to meet safety requirements.

Conclusion 6: Additional testing and experimentation are required in order to more rationally set a siloxane standard in the future.

Conclusion 7: There is not enough scientific evidence to support an increase or a decrease in maximum allowable concentrations.

Recommendation 3: Support a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes.

Recommendation 4: There is not enough evidence to recommend any changes to the maximum allowable siloxanes concentration at this time.

Currently, ASTM International is in the process of developing a standard test method for siloxane measurement and quantification in order to determine the gas-phase concentrations of volatile silicon compounds in the ppb_v to ppm_v concentration range (ASTMWK52796, 2018). The membership of the ASTM WK52796 sub-committee includes participation from major analytical laboratories, engine manufacturers, control gas sample vendors, and gas utilities. The ASTM WK 52796 process has proceeded since 2014, with the most recent subcommittee ballot vote closing on February 8, 2018. There was one negative vote on this ballot. A method is not advanced until all negative votes are addressed, and this negative vote will be addressed at the subcommittee's June 2018 meeting.

At the conclusion of the ASTM International process, a standard method will be published, and the organization will have five years to complete the interlaboratory study. The objective of the interlaboratory study is to, through the participation of several laboratories, quantify the precision and bias of the standard test method. This should help alleviate industry concerns about reliable detection limits. After this stage is complete, the standard test method can be used by siloxane removal equipment manufacturers to rigorously test the effectiveness of their removal processes and possibly offer performance guarantees, which will assist in financing of biomethane projects.

Finding: ASTM International is developing a standard test method for siloxane measurement and quantification in order to determine the gas-phase concentrations of volatile silicon compounds in the ppb_v to ppm_v concentration range. Once done, it will be tested by labs over a five-year period.

Recommendation 6: Monitor the ASTM International process to adopt and test a standard test method for siloxanes.

Recommendation 7: Use the learnings from the siloxane research and the ASTM International process to revisit the siloxane maximum standards once more complete information becomes available.

5.8 Synthesizing conclusions and recommendations

After review of available evidence, the following conclusions are reached:

1. Siloxanes, even at very low concentrations, can inflict considerable damage upon and decrease the lifetime of combustion equipment, post-combustion catalysts, and other energy conversion equipment (e.g. fuel cell systems).
2. Damage is very specific to appliance geometry and sensitivities. Some appliances may be gradually deactivated due to silica buildup on heat exchangers. Some appliances may be quickly deactivated due to silica deposition on key sensors. This makes it difficult to generalize conclusions from the relatively small numbers of empirical tests.
3. There is currently no scientific consensus on a protocol for reliable measurement of volatile silicon-containing compounds in a gaseous fuel. However, there are laboratories that currently claim to provide the required level of precision to satisfy the California utilities. The ongoing development of an ASTM International standard will help in this regard.
4. There is not enough data at this time to produce reliable insight as to whether 0.1 mg Si/m³ is too stringent or not stringent enough to meet safety requirements. While we do not find the current specification to be robustly supported by thorough scientific study, we also do not find convincing evidence for relaxing the specification.
5. The current specification can be met with sufficient removal equipment and robust measurement methods, as evidenced by the successful Point Loma WWTP biomethane project. The industry would benefit from greater transparency from SoCalGas regarding the process by which the Point Loma WWTP biomethane was certified to be in compliance with the siloxane standard. The Point Loma project could serve as a template other projects may follow. More clarity regarding the measurement technique, certifying laboratory, and expected detection limits would aid the development of additional projects seeking to demonstrate compliance with the siloxane specification.
6. Sources in which siloxanes are not expected to be present (such as dairies, food waste digestion, or agricultural waste digestion) ought to be held to a reduced and simplified verification regime to avoid unnecessarily encumbering sources which do not produce siloxanes

The general lack of empirical evidence relating to siloxane impacts is unsatisfactory and leads to uncertainty in designing acceptable maximum siloxane concentrations. The current maximum siloxane specification of 0.1 mg Si/m³ is largely based on the study of one or two combustion applications and reported engine specifications by engine manufacturers. The chosen value of 0.1 mg Si/m³ appears to be more of an order of magnitude estimate rather than a robustly supported maximum that will ensure safe operation of the wide variety of grid-connected combustion equipment. However, due to the investment risk introduced by uncertainty in measurement of siloxanes at these levels, it is likely that the maximum siloxane specification (if unaltered) will continue to serve as a significant barrier to biomethane development in California.

In order to reduce the uncertainty of siloxane impacts and provide better scientific basis for regulation, the following key questions must be addressed:

1. Sampling and analysis methods for siloxane quantification must be standardized. This process is well underway with ASTM International. If the uncertainties surrounding the reliable detection of siloxane compounds are not managed, this will deter investment and California will see limited development of both landfill and WWTP sources of biomethane.
2. The impact of siloxanes on end-use equipment must be thoroughly studied. Existing studies show that significant damage can be done to combustion equipment, even at very low levels of siloxane concentration, depending on the appliance geometry and sensitivities. In order to scientifically justify a maximum permissible siloxane specification, there would need to be further experimental study on common appliances in California.
3. The validity of the linear extrapolation used in setting the current specification must be examined by studying deposition with low concentration fuels for longer periods of time, ideally in multiple equipment types.
4. The prevalence and potential severity of failure modes must be examined. Given the variety of equipment in operation in California, no understanding is available as to what fraction of device damage and failure could possibly present safety risks via CO emissions versus what fraction would result in a fail-safe state.
5. The potential human health effects of amorphous silica nanoparticles need to be further understood. The gas quality specifications ought to ensure that combustion products of biomethane do not pose any greater health risk than the combustion products of NG.
6. Systematic collection of operational experience data in existing landfill and WWTP plants must occur, including sampling of gas quality and siloxane concentrations. Clearly, many operational projects currently inject landfill-derived biomethane

without ill effects, but it is not clear from available data what insights can be drawn from such experience. For example, for the landfills that have been safely injecting biomethane (see section 5.3 above), we lack data required to know if those experiences support or refute stringent specifications.

Chapter 6

Implications of gas quality specifications for cost and value of biomethane in California

The cost of biomethane production includes a variety of components, including feedstock gathering and handling, anaerobic digestion, gas upgrading and purification, gas compression and injection, and gas line interconnection. Due to the scope of this report, we do not focus in this chapter on the overall cost of biomethane production. Instead, we focus only on the cost implications of the HV and siloxane specifications. Reviews of the overall cost of biomethane production are cited below.

6.1 Cost implications of HV specifications

The HV specification affects the cost of biomethane production because raw biogas upgrading comprises a large portion of capital and operating costs for biomethane production (Ong et al., 2014). Upgrading costs affect the feasible volumes of cost-effective biomethane produced. Appendix D provides a technical overview of available biogas upgrading technologies.

6.1.1 Survey of equipment vendors for cost of upgrading biogas to 970 Btu/scf and 990 Btu/scf

Existing analyses of upgrading costs do not contain enough detail to determine the cost impacts of different HV specifications (Bauer, Hulteberg, Persson, & Tamm, 2013b; Electrigaz Technologies Inc., 2011; Hagen & Polman, 2001). We contacted manufacturers of upgrading equipment to obtain estimates of the cost of gas cleanup for the different HV specifications (970 BTU/scf and 990 BTU/scf) specific to the four sources of biogas: dairy manure; landfill; municipal solid waste (MSW), defined as landfill-diverted organics such as yard waste, food waste, etc.; and WWTP.

Biomethane upgrading equipment manufacturers were asked to provide capital and operating cost estimates for their equipment to upgrade biogas to HV specifications of 970 BTU/scf and 990 BTU/scf. To ensure uniform data reporting, each manufacturer was provided with a standard Information Request Document. This document explained the intent of the research and requested specific information for several template facilities. A copy of the document is included in Appendix E.

Four template facilities were created representing each of the four major sources of biomethane: landfill, WWTP, MSW, and dairy AD (Myers Jaffe, 2016). Representative

compositions and flow rates were determined for each template facility (Table 11. Representative gas compositions given to vendors of upgrading system for cost estimation.). While these values for each source gas depend on the project specifics, the modeling assumptions are based on expected sizes of prospective biomethane production facilities in California (Electrigaz Technologies Inc., 2011; Parker, Williams, Dominguez-Faus, & Scheitrum, 2017).

Table 11. Representative gas compositions given to vendors of upgrading system for cost estimation.

Source	Flow rate	Flow rate	Representative raw biogas composition (vol. %)			
	[m ³ /h]	[mscf/h] ^a	CH ₄	CO ₂	N ₂	O ₂
Landfill (LF)	1,110	38.86	45%	40%	14%	2%
Wastewater treatment plant (WWTP)	300	10.60	60%	38%	1%	1%
Dairy AD	150	5.30	55%	44%	0.5%	0.5%
Municipal solid waste (MSW)	700	24.73	58%	37%	4.5%	0.5%

a – converted from standard cubic meters at 101.325 kPa and 15 °C to standard cubic feet at 14.73 psia and 60 °F.

h = hour

For each source gas, the IRD asks for the cost of conditioning/pretreatment and the costs to upgrade to either 970 BTU/scf or 990 BTU/scf. For this study, we consider upgrading to be the process used to increase HV by rejecting inerts; all other constituent removal is considered conditioning. The conditioning process removes trace constituents such as volatile organic compounds (VOCs), ammonia, hydrogen sulfide (H₂S), and PCBs (polychlorinated biphenyls). In cases where siloxanes would be present, designs will remove those (i.e., costs are inclusive of siloxane removal). Conditioning costs are not affected by differences in pipeline injection HV specifications and are more driven by the trace constituent profile of the gas. Requested parameters were: equipment costs (with installation cost included), equipment life, monthly operations and maintenance costs, media replacement costs, media life, outlet flow rate, and outlet pressure (See Appendix E for definitions).

Over the course of two months, 81 individuals representing 28 companies were contacted by email or phone with a request to participate. Each individual was contacted biweekly until they responded to the request or the survey period ended. Of 28 companies initially contacted, 18 companies responded with interest or follow-up questions. Seven companies eventually provided detailed cost estimates and values for above requested parameters. Due to privacy concerns, these companies have been anonymized in all datasets below, and we do not specify which of the 28 companies replied in full. (See Appendix E for the list of all companies contacted.)

Survey responses from manufacturers were not all complete. Some manufacturers only design systems for specific source gases, and so only responded for relevant systems. Some manufacturers separated the cost of conditioning (removing contaminants from raw biomethane) from the cost of upgrading, while others included conditioning costs in their upgrading costs. Some report a single aggregate average monthly operating cost, while

some separated monthly expenses for energy and operations from cost of replacement of membranes and other materials annually or once every five to ten years. Data received from each of the seven vendors who responded with cost estimates is shown in Table 12. Table of cost estimates received from vendors. Table shows data to a single common unit for distinct type of information. below. Figure 13. Distribution of vendor estimates of upfront capital cost which includes both equipment and installation cost. See Table 12. Table of cost estimates received from vendors. Table shows data to a single common unit for distinct type of information. for a complete list of individual vendor's estimates. and Figure 14. Distribution of vendor estimates of monthly operating capital cost of upgrading and cleanup equipment. See Table 12. Table of cost estimates received from vendors. Table shows data to a single common unit for distinct type of information. for a complete list of individual vendor's estimates. show the distribution of capital and operating cost estimates.

It is worth emphasizing that the cost estimates below, as provided by equipment manufacturers, do not represent the complete costs of a biomethane system. The goal of this study was not to estimate complete costs of biomethane, but rather to estimate the cost impacts of differential HV specifications of 970 BTU/scf and 990 BTU/scf.

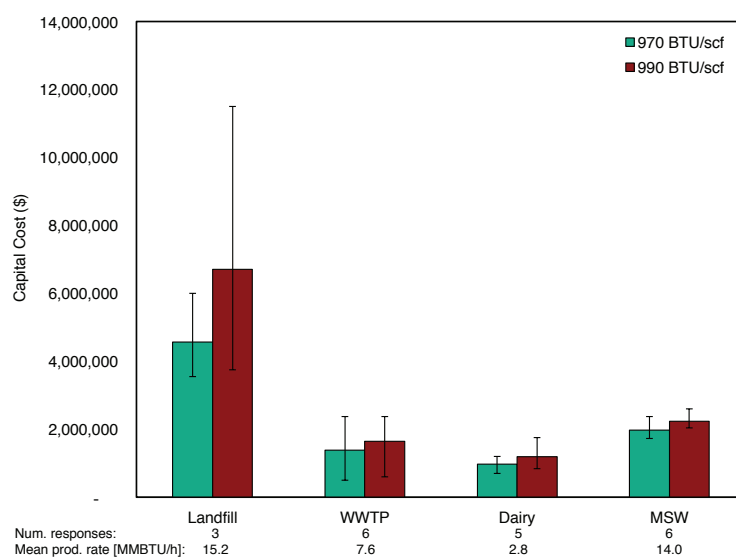


Figure 13. Distribution of vendor estimates of upfront capital cost which includes both equipment and installation cost. See Table 12. Table of cost estimates received from vendors. Table shows data to a single common unit for distinct type of information. for a complete list of individual vendor's estimates.

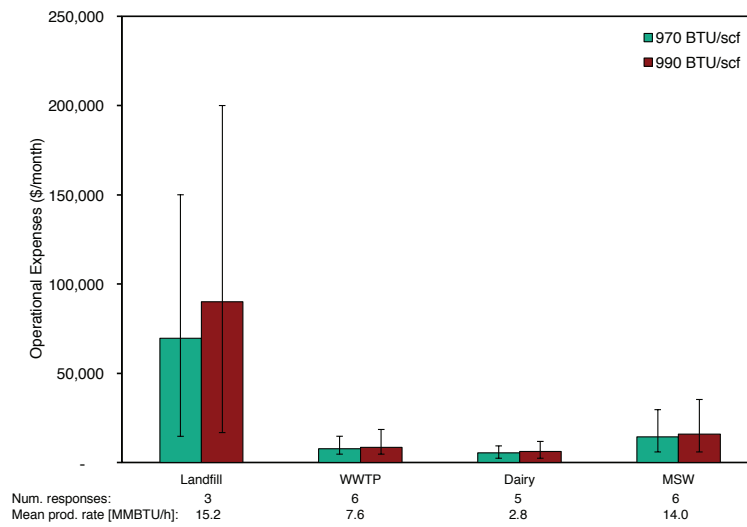


Figure 14. Distribution of vendor estimates of monthly operating capital cost of upgrading and cleanup equipment. See Table 12. Table of cost estimates received from vendors. Table shows data to a single common unit for distinct type of information. for a complete list of individual vendor's estimates.

Table 12. Table of cost estimates received from vendors. Table shows data to a single common unit for distinct type of information.

Company	A		B		C		D		E		F		G		Average	
	990	970	990	970	990	970	990	970	990	970	990	970	990	970	990	970
	BTU/scf															
	Landfill	-	4,875,000	4,160,000	-	-	11,500,000	6,000,000	-	-	-	-	3,750,000	3,550,000	6,708,333	4,570,000
Capital cost (\$)	WWT	600,000	1,430,000	1,131,000	1,500,000	1,500,000	-	-	2,374,133	2,374,133	1,950,000	1,235,000	2,050,000	1,550,000	1,650,689	1,381,689
	Dairy	840,000	700,000	1,183,000	910,000	1,200,000	-	-	-	-	1,755,000	1,105,000	960,000	960,000	1,187,600	975,000
	MSW	2,160,000	1,800,000	2,171,000	1,729,000	2,040,000	-	-	2,374,133	2,374,133	2,600,000	1,820,000	2,100,000	2,100,000	2,240,856	1,977,189
	Landfill	-	-	53,700	44,100	-	200,000	150,000	-	-	-	-	16,750c	14,667c	90,150	69,589
Operating cost (\$/month)	WWT	-	18,500	14,700	5,160	5,160	-	-	5,906c	5,906c	-	-	4,667c	4,667c	8,558	7,608
	Dairy	-	11,800	9,300	4,560	4,560	-	-	-	-	-	-	2,375c	2,375c	6,245	5,412
	MSW	-	35,300	29,600	12,000	12,000	-	-	5,906c	5,906c	-	-	10,250c	10,250c	15,864	14,439
	Landfill	-	-	20	20	-	20	20	-	-	-	-	20	20	20	20
Equipment lifetime (yr)	WWT	20b	20	20	15	15	-	-	25	25	20b	20b	20	20	20	20
	Dairy	20b	20	20	20	20	-	-	-	-	20b	20b	20	20	20	20
	MSW	20b	20	20	15	15	-	-	25	25	20b	20b	20	20	20	20
	Landfill	-	106,997a	112,900a	-	-	159,672a	156,447a	-	-	-	-	133,139	136,261	133,269	135,203
Annual Gas production (MMBTU/yr)	WWT	53,387b	41,523a	44,753a	55,365	55,215	-	-	138,082a	132,709a	53,387b	52,309b	56,024	59,090	66,295	66,064
	Dairy	24,469b	18,216a	19,713a	27,188	27,220	-	-	-	-	24,469b	23,975b	26,694	27,446	24,207	24,466
	MSW	124,570b	92,736a	100,355a	126,877	126,897	-	-	138,082a	132,709a	124,570b	122,054b	126,877	129,803	122,285	122,312
	Landfill	-	12,21a	12,89a	-	-	18,23a	17,86a	-	-	-	-	15	16	15.2	15.4
Gas production (MMBTU/h)	WWT	6b	4,74a	5,11a	6.32	6.30	-	-	16a	15a	6b	6b	6	7	7.6	7.5
	Dairy	3b	2,74b	2,08a	3.10	3.11	-	-	0a	0a	3b	3b	3	3	2.8	2.8
	MSW	14b	10.59a	11.46a	14.48	14	-	-	16a	15a	14b	14b	14	15	14.0	14.0

Notes:

See Table 11. Representative gas compositions given to vendors of upgrading system for cost estimation. for flow rates and gas composition information provided to vendors for cost estimates.

a – Vendor data converted to different units – either from a different currency to \$US or physical unit conversion.

b - Data required for cost analysis but was not provided by a vendor and therefore set to default assumption.

c - Aggregation of different operating expenses in to a single average monthly operating cost.

6.1.2 Estimating the Levelized Cost of Upgrading Biogas (LCUG) based on vendor data

Survey data were used to calculate a levelized cost in \$/MMBTU across an estimated 20-year life of the upgrading equipment, which we abbreviate as LCUG. The LCUG is the net present value (NPV) of the unit cost of upgrading gas over the life of the investment into cleaning and upgrading raw biogas to pipeline specifications, including both capital and operating expenses. Once again, please note that this is not the levelized cost of biomethane, estimating which requires inclusion of the costs of raw biogas production and pipeline interconnection. In the next section, we relate our own estimates of upgrading cost to those in the literature and discuss its implications for estimates of levelized cost of biomethane reported in the literature. The LCUG is calculated by leveling the total life cycle cost (TLCC) of the investment across all units of gas upgraded over the life of the project. This is done by computing a hypothetical price of gas, p in \$/MMBTU, to be paid for upgraded gas and then computing the present value of this stream of revenues and equating this to the TLCC such that the investment breaks even.

Mathematically, the LCUG is computed in the following sequence:

$$TLCC = CAPEX + \frac{\text{Annual OPEX}}{CRF} \quad (1)$$

where $CAPEX$ is initial capital cost, $OPEX$ refers to annual operating costs, and CRF is the Capital Recovery Factor. The CRF is the ratio of a constant annuity to the present value of receiving that annuity for a given length of time, computed as:

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1} \quad (2)$$

where N is the investment lifetime and r is the real discount rate, henceforth, simply discount rate. Since future cash flows are inherently uncertain, risk is inherent to any calculation of present worth (Damodaran, 2007). The most common approach to handling risk is to use a higher discount rate to reflect a riskier investment (Damodaran, 2007). We use a discount rate of 12% as the base case, as in Jaffe et al. (Myers Jaffe, 2016). We assume that estimates of capital and operating expenditures as well as gas quality and production rates are expected values.

The present value (PV) of receiving p [\$/MMBTU] for an upgraded biomethane output of q [BTU/hour]

$$PV = \frac{p \cdot q \cdot 8760 \cdot C_f}{CRF} \quad (3)$$

where 8760 is the hours per year and is an assumed plant capacity factor.

Equating (1) and (3) and solving for the price, p :

$$p = \frac{TLCC \cdot CRF}{q \cdot 8760 \cdot C_f} \quad (4)$$

We compute the LCUG for each vendor for each different source of biomethane using equations and data from above. CAPEX, OPEX and equipment life are data received from vendors while discount rate and the capacity factor are inputs we assume. For capacity factor, we chose 80% as a base case value. Results for estimated LCUG under these assumptions are presented in Table 13. Estimates of LCUG (\$/MMBTU) for a discount rate of 12% and a capacity factor of 80%. and Figure 15. Levelized cost (in \$/MMBTU) of upgrading gas (LCUG) to pipeline standards assuming a 12% discount rate and capacity factor of 80%. The solid bars show the mean of the individual cost estimate while the whiskers for each solid bar show the minimum and maximum individual cost estimate. The number of responses received (N) and the mean biomethane flow rate (in MMBTU/hour) across different vendor estimates for each type of application..

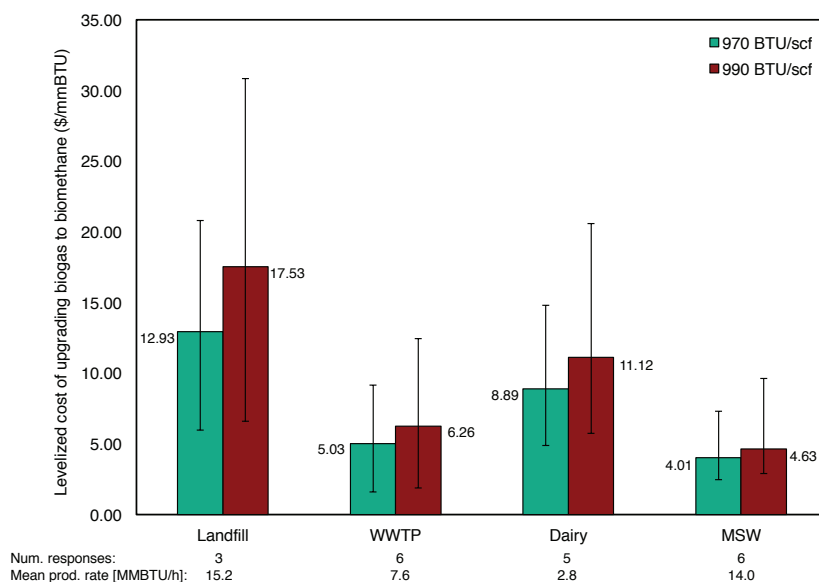


Figure 15. Levelized cost (in \$/MMBTU) of upgrading gas (LCUG) to pipeline standards assuming a 12% discount rate and capacity factor of 80%. The solid bars show the mean of the individual cost estimate while the whiskers for each solid bar show the minimum and maximum individual cost estimate. The number of responses received (N) and the mean biomethane flow rate (in MMBTU/hour) across different vendor estimates for each type of application.

Table 13. Estimates of LCUG (\$/MMBTU) for a discount rate of 12% and a capacity factor of 80%.

Source	Raw biogas flow rate (Nm ³ /h)	Num. vendor quotes	Mean biomethane production flow rate (MMBTU/h)		LCUG in \$/MMBTU for 990 BTU/scf			LCUG in \$/MMBTU for 970 BTU/scf		
			990 BTU/scf	970 BTU/scf	Min	Mean	Max	Min	Mean	Max
Landfill	1110	3	15.2	15.4	6.60	17.53	30.84	5.97	12.93	20.80
WWTP	300	6	7.6	7.5	1.88	6.26	12.45	1.60	5.03	9.16
Dairy	150	5	2.8	2.8	5.74	11.12	20.58	4.89	8.89	14.80
MSW	700	6	14.0	14.0	2.90	4.63	9.63	2.47	4.01	7.31

There is substantial variability between LCUG estimates across both raw biogas source and across vendors for each of the four sources. Landfill scenarios result in higher LCUG relative to the other three applications due to higher gas conditioning costs and the higher cost of N₂ removal. For every scenario, it is more expensive to upgrade the biogas to 990 BTU/scf as compared to 970 BTU/scf, resulting in increased LCUG by 14–35% on average. This is especially noteworthy for the landfill source gas, which is high in N₂.

The difference in the estimated cost of upgrading between the 970 BTU/scf and 990 BTU/scf standard is also highest for biogas from landfills, with 990 BTU/scf increasing the cost

of biomethane by \$4 to \$5 per MMBTU. The higher standard (990 BTU/scf) would raise the cost of biomethane by approximately \$2 per MMBTU for dairy and around \$1 per MMBTU for wastewater facilities and MSW sources.

To meet a 990 BTU/scf minimum HV specification effectively requires 98 vol.% CH₄, making some upgrading options infeasible. Methods that would normally have high CH₄ recovery, such as chemical scrubbing or water scrubbing, are generally not viable if the raw biogas contains more than 2% N₂ or O₂. This is highly impactful to California biomethane supply as landfills are the largest potential source of biomethane in California by a significant margin (Parker et al., 2017).

6.1.3 Economics of blending propane for meeting HV specification

One alternative approach to meeting any given standard such as 990 BTU/scf minimum HV is to blend lower-HV biomethane with propane, which has a much higher HV. If the cost of procuring, storing, and mixing propane through a dedicated system prior to pipeline injection is lower relative to the incremental cost of upgrading biogas up to a given standard, then blending might be preferred. The current wholesale price of propane is about \$1/gallon¹. Given a gas mixture that meets all gas quality specifications except for HV, between 0.5 and 1.5 vol.% of propane will need to be added in order to upgrade the HV to the required 990 BTU/scf. This translates to between \$0.25 and \$0.50 per MMBTU of product gas. Of course, the total cost of blending propane would be higher when one accounts for capital and operating costs for storage and mixing of propane with biomethane. This suggests that, depending on the major component composition of the biomethane, the most economical way to upgrade marginally from 970 BTU/scf to 990 BTU/scf may be propane addition.

Finding: Blending of upgraded biogas with natural gas in or at the pipeline might allow safe pipeline movement of upgraded biogas that does not meet all specifications, but only under very specific conditions, typically dictated by the pipeline company.

6.1.4 Sensitivity to discount rate and capacity factor

Table 14. Sensitivity of LCUG (\$/MMBTU) to discount rate and capacity factor. shows the sensitivity of LCUG to discount rate and capacity factor. In general, private investments typically employ a higher discount rate while public investments tend to be assessed at lower

1. https://www.eia.gov/dnav/pet/pet_pri_wfr_a_EPLLP_PWR_dpgal_w.htm

social discount rates.² All else equal, a higher discount rate means a higher LCUG while a higher capacity factor means a smaller LCUG.

Table 14. Sensitivity of LCUG (\$/MMBTU) to discount rate and capacity factor.

		990 BTU/scf			970 BTU/scf		
		Min	Mean	Max	Min	Mean	Max
Disc. Rate 12% Cap. fac. 80%	Landfill	6.6	17.5	30.8	6.0	12.9	20.8
	WWT	1.9	6.3	12.4	1.6	5.0	9.2
	Dairy	5.7	11.1	20.6	4.9	8.9	14.8
	MSW	2.9	4.6	9.6	2.5	4.0	7.3
Disc. Rate 6% Cap. fac. 80%	Landfill	5.0	14.7	26.6	4.5	11.0	18.6
	WWT	1.2	4.7	10.4	1.0	3.8	7.7
	Dairy	3.7	8.2	16.8	3.2	6.5	12.1
	MSW	1.9	3.5	8.3	1.6	3.1	6.3
Disc. Rate 6% Cap. fac. 90%	Landfill	4.4	13.1	23.7	4.0	9.7	16.5
	WWT	1.1	4.2	9.3	0.9	3.4	6.8
	Dairy	3.3	7.3	14.9	2.8	5.8	10.8
	MSW	1.7	3.1	7.3	1.4	2.7	5.6
Disc. Rate 12% Cap. fac. 90%	Landfill	5.9	15.6	27.4	5.3	11.5	18.5
	WWT	1.7	5.6	11.1	1.4	4.5	8.1
	Dairy	5.1	9.9	18.3	4.3	7.9	13.2
	MSW	2.6	4.1	8.6	2.2	3.6	6.5

6.1.5 Comparison to prior studies that estimate upgrading costs

There are a number of recent studies examining or reporting the cost of upgrading. We summarize the results from these studies below in . We see that our derived cost estimates for upgrading are generally similar to those from the literature for our MSW, dairy, and WWTP cases. However, our landfill gas case is significantly more expensive, due to additional cleanup required for landfill gas usage.

Of particular relevance is the Jaffe et al. study of 2016, which examined biomethane production specifically in California. Comparing our cost of upgrading estimates to those reported in Myers Jaffe (2016), our mean estimates of \$17.5/MMBTU and \$11.1/MMBTU for upgrading landfill and dairy biogas to 990 BTU/scf, respectively, both lie within Jaffe's ranges

2. For instance, the U.S. Government Interagency Working Group on Social Cost of Carbon estimates the social cost of carbon by discounting future damages from climate change at three fixed rates of 2.5%, 3%, and 5% (Interagency Working Group on Social Cost of Greenhouse Gases, 2016). However, estimating the levelized cost of biomethane using low discount rates will yield unrealistically low estimates of the minimum price for biomethane that a project developer would need to break-even on his investment.

of \$6 to \$43 per MMBTU, and 10 to \$180/MMBTU landfill and dairy respectively. However, our mean estimates for WWTP (\$6.3/MMBTU) and MSW (\$4.6/MMBTU) were below Jaffe's estimates of \$9 to \$90/MMBTU and \$10/MMBTU for WWTP and MSW respectively.

Finding: There is substantial variability in upgrading costs across varying sources of biogas and varying vendor-supplied estimates. Seven companies, out of 28 initially contacted, provided detailed cost estimates. Mean estimates of upgrading biogas to biomethane, at 970 BTU/scf, range from \$5 to \$18 per MMBTU. The mean estimates of the additional cost of upgrading to 990 BTU/scf rather than 970 BTU/scf are between \$1 and \$5 per MMBTU.

Note that economies of scale affect the costs of upgrading significantly. This has been noted in numerous sources, including the Jaffe et al. study (Myers Jaffe, 2016). Note that our MSW case and our dairy case both produce a high-quality gas stream with similar compositions, but that our dairy case has a flow rate of ~5 mscf/h, while the MSW case has a flow rate of ~25 mscf/h. The resulting LCUG for MSW is approximately half that of dairy. Thus, it should be noted that the per-MMBTU costs for dairy here could be reduced if aggregation of dairy gas for central processing, or co-digestion was used to increase production volumes.

Table 15. Cost of upgrading from various literature surveys. All estimates converted to \$/MMBTU using conversion ratios of 38.4 scf/Nm³ and 1.21 USD per EUR.

Technology	Study	Flowrate [Nm ³ /h]	Upgrading Cost (\$/MMBTU)
Water scrubbing	(Ong, Williams, & Kaffka, 2017)	130–160	4.69
	(Pierre et al., 2016)	230	4.14
	(Ullah Khan et al., 2017)	200–300	4.77
Chemical abs.	(Ong et al., 2017)	130–160	6.26
	(Pierre et al., 2016)	230	7.96
	(Ullah Khan et al., 2017)	200–300	8.28
PSA	(Ong et al., 2017)	130–160	9.12
	(Pierre et al., 2016)	230	5.41–8.91
	(Ullah Khan et al., 2017)	200–300	8.28
	(Angelidaki et al., 2018)	100	7.09
Membrane	(Ong et al., 2017)	130–160	4.43
	(Pierre et al., 2016)	230	7.00
	(Ullah Khan et al., 2017)	200–300	7.00

6.2 Review of cost implications of siloxane specifications

Whereas for the HV specifications, we conducted our own survey of equipment manufacturers and vendors, we draw upon on a nationwide survey of biogas cleanup technologies and costs with specific focus on siloxane removal that was carried out by GTI in 2014 (Baez & Hill, 2014). A vendor questionnaire was sent to 15 manufacturers of siloxane removal systems and received nine survey responses. The cost of these siloxane removal systems

varies greatly, and economies of scale are observed when compared on a per standard cubic foot per minute (scfm) basis. GTI also reviewed the literature for cost data for siloxane removal systems and provided a tabulated summary of 16 different projects that were either operational or proposed. Based on these data, cost curves and an open-source toolkit were constructed in order to estimate the cost of a biogas cleanup system by flow rate (Baez & Hill, 2014).

The survey responses indicate most companies claim to remove upwards of 99% of the siloxanes, down to concentrations of 0.1 ppm_v (~0.47 mg Si/m³ evaluated as D4). While these removal claims are not sufficient to meet the current specifications in place in California, these are the best available cost data at this time. Leveraging the biogas cost toolkit developed by GTI (Baez & Hill, 2014), the costs of siloxane removal for each MMBTU of biomethane produced can be estimated as a function of scale (scfm of raw biogas flow). Displayed below in Figure 16. Cost of siloxane removal in \$/MMBTU as a function of scale (scfm)., while the costs drop due to economies of scale, the additive cost of siloxane removal remains above \$1/MMBTU for most flow rates.

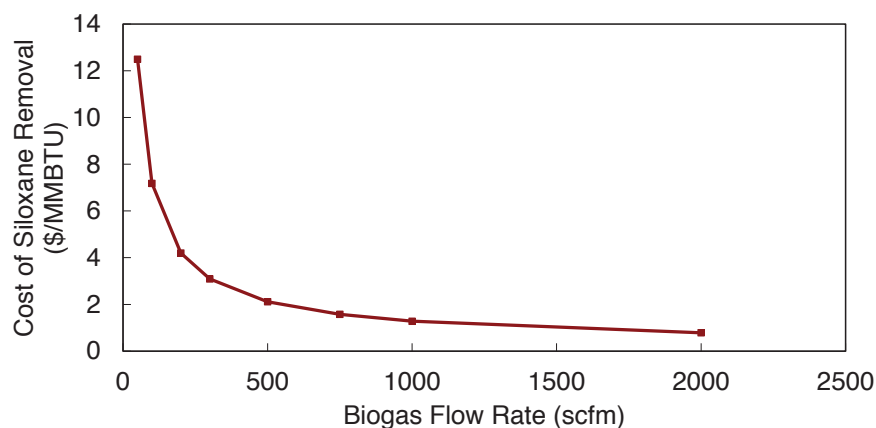


Figure 16. Cost of siloxane removal in \$/MMBTU as a function of scale (scfm).

Importantly, no manufacturer of siloxane removal equipment has thus far been willing to provide a performance guarantee for removal below 1 mg Si/m³ (CRNG, 2016). This can complicate the economics of biomethane projects, as it is difficult to acquire capital without a financially-backed guarantee that the project will be able to meet the specifications required for pipeline interconnection and addition. As there is skepticism of the ability to reliably measure siloxanes at the levels mandated in California, few developers are willing to accept the risk of shut-in due to measurement error. Projects that have gone forward, such as the Point Loma WWTP discussed above, have significant public financing components which reduce financial risk in the absence of guarantees.

Note that the costs of siloxane removal discussed above are also included in our LCUG calculations from the previous sections, because responding companies designed systems to handle the contaminant stream expected for each type of gas.

6.3 Regulatory incentives affecting the economics of pipeline injection of biomethane

Biomethane has value above and beyond its energy content due to two key regulations: the U.S. Federal Renewable Fuel Standard (RFS) (Renewable Fuel Standard, 2018) and the California Low Carbon Fuel Standard (LCFS) (CARB, 2018). Under each of these policies biomethane projects generate credits that obligated parties can purchase for meeting their compliance obligations. In this section, we analyze the economic incentives that benefit biomethane production under each of these regulations. Note that given the illustrative nature of these calculations we exclude costs such as those associated with obtaining certification and quality assurance for credit generation. We also ignore regulatory uncertainty that introduces risk.

6.3.1 Biomethane under the RFS

Under the RFS, biomethane, from various sources and in various forms, qualifies for compliance with ‘cellulosic’ biofuel targets (Renewable Fuel Standard, 2018). Specifically, according to the EPA, the following sources are designated pathways (Q pathway)³ for compliance with the cellulosic biofuel mandate portion of the RFS.

1. Producing renewable compressed natural gas
2. Renewable liquefied natural gas or renewable electricity derived from biogas from landfills
3. Municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters
4. The cellulosic components of biomass processed in dedicated organic waste digesters

Each source that generates D3 RINs⁴ while deriving the same from biogas generated

3. <https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel>

4. D-code 3 refers to cellulosic biofuel originally defined as renewable fuel from cellulose, hemicellulose and lignin, with a life cycle GHG intensity at least 60% below that for baseline petroleum. D-code 5 refers to advanced biofuel made from any type of renewable biomass except corn starch ethanol, with a lifecycle GHG intensity at least 50% below that for baseline petroleum. For a complete definition of all D-codes under the RFS see <https://www.epa.gov/renewable-fuel-standard-program/what-fuel-pathway#RIN>

by mixed-waste digesters is a pathway (T pathway) for compliance with the advanced biofuel mandate portion of the RFS, and thereby, generates what are called D5 RINs. For information purposes, the other categories of RINs under the RFS are D4 (biomass-based diesel), D6 (renewable fuel which refers to ethanol from corn starch), and D7 RINs (cellulosic diesel). With targets for cellulosic biofuels being the most stringent to achieve, D3 RINs are the most scarce and the most valuable type of RIN. For reference, prices in spring 2018 have traded in the range of \$2.50–\$3.00 per D3 RIN, \$0.65–\$0.95 for D4 and D5 RINs, and \$0.35–\$0.65 per RIN for D6 (ethanol) RINs (PFL Fuel Services, 2014).

In times of under-production of cellulosic ethanol (scarce D3 RINs), the EPA is required to both reduce the renewable volume obligation (RVO) and allow regulated parties to purchase and retire cellulosic waiver credits (CWC) and/or D5 RINs for compliance with the revised RVO for that year (EPA, 2016). EPA must reduce the required volume of cellulosic biofuel for that year to the projected volume, and must provide obligated parties the opportunity to purchase cellulosic waiver credits (CWC). The price of CWC credits is bounded by an EPA specified formula. According to the EPA, the cellulosic waiver credit price is the greater of \$0.25 or \$3.00 minus the wholesale price of gasoline, adjusted for inflation (EPA, 2016). EPA must reduce the required volume of cellulosic biofuel for that year to the projected volume, and must provide obligated parties the opportunity to purchase cellulosic waiver credits (CWC). For example, in 2018 the original RFS2 mandated target for cellulosic biofuel was 7 billion gallons, while the revised target was set to 0.288 billion gallons (Renewable Fuel Standard Program: Standards for 2018 and Biomass-Based Diesel Volume for 2019, 2017).

To illustrate the value of RINs for California biomethane projects, consider this simple example. For March 12, 2018, the observed prices were (ecoengineers.us):

- Each MMBTU of biomethane generates about 11.73 RINs (Williams, 2017).
- D3 RIN price (p^{D3}) = \$2.45/RIN
- D5 RIN price (p^{D5}) = \$0.72/RIN
- CWC price (p^{CWC}) = \$1.96/RIN, price fixed by EPA for year 2018 (EPA, 2016). EPA must reduce the required volume of cellulosic biofuel for that year to the projected volume, and must provide obligated parties the opportunity to purchase cellulosic waiver credits (CWC).

Since $p^{D3} < p^{D5} + p^{CWC}$, an obligated party would purchase a D3 RIN under current conditions.

- Revenue from D3 RINs = 11.73 RINs/MMBTU \times \$2.45/RIN = 28.74 \$/MMBTU

The D3 RINs available under current RFS prices are worth approximately 10 times the prevailing spring 2018 wellhead price of natural gas per MMBTU.

6.3.2 Biomethane under the California LCFS

Biomethane projects for pipeline injection are eligible to generate credits under the California LCFS provided they demonstrate a vehicular fuel end-use. California LCFS credits are denominated in metric tonnes of CO₂ equivalent avoided. Under the RFS, the number of RINs is independent of the actual carbon intensity (CI) of biomethane. However, under the LCFS, the number of credits per unit of biomethane dependent on the carbon intensity (CI) rating of a given project relative to gasoline or diesel. Table 16. Carbon intensity (CI) ratings (gCO₂e/MJ) for currently certified pathways for renewable CNG derived from different feedstocks and delivered via pipelines. This list includes facilities producing RNG located outside California. contains CI values for currently certified pathways that deliver compressed natural gas (CNG) both in liquefied and non-liquefied form, as given in CARB LCFS Pathway Certified Carbon Intensities (CARB, 2018).⁵ Some of the higher values result from transportation and additional steps required for out-of-state gas.

Table 16. Carbon intensity (CI) ratings (gCO₂e/MJ) for currently certified pathways for renewable CNG derived from different feedstocks and delivered via pipelines. This list includes facilities producing RNG located outside California.

Feedstock	Delivered fuel	# of certified pathways	Carbon Intensity gCO ₂ e/MJ			
			Mean	Median	Min	Max
AD Wastewater Sludge	CNG	2	19.34	19.34	7.75	30.92
Animal Waste	CNG	2	-263.96	-263.96	-272.97	-254.94
Landfill Gas	CNG	29	48.08	46.65	37.13	67.17
Landfill Gas - CNG	CNG	16	34.78	34.60	30.50	38.56
Landfill Gas - L-CNG ^a	CNG	14	55.26	54.01	45.31	80.62

a - Landfill gas generated outside CA, delivered by pipeline to an intermediate point, followed by liquefaction, followed by transportation. trucks and then re-gasified and re-compressed in CA

To illustrate the value of California LCFS credits for California biomethane projects, assume we are producing biomethane from anaerobic digestion of dairy waste and that it displaces California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).⁶ The

5. For a complete list of approved compliance pathways and their approved emission intensity ratings see <https://www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm>

6. If biomethane displaces compressed or liquefied natural gas used in a heavy-duty, spark-ignited or compression-ignition engine, then it will be treated as displacing diesel and one has to compute an adjusted carbon intensity of biomethane. The adjustment is done to account for the differences in energy efficiency among different types of fuels and vehicles. The adjustment factor, a dimensionless number, is called the Energy Economy Ratio (EER) and it is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel. The EER for Compressed or Liquefied Natural Gas when displacing diesel is 0.9 and therefore, the EER adjusted CI of RNG would be the CI of RNG/EER. For a detailed discussion of the EER see the Report Proposed Regulation to Implement the Low Carbon Fuel Standard Volume I Staff Report: Initial Statement of Reasons https://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf (link last accessed on April 23, 2018).

average price of LCFS credit for the week of February 2 to March 4, 2018, is \$125.89 per MTCO_{2e} (Retrieved from the CARB Weekly LCFS Credit Transfer Activity Report (CARB, 2018).) For reference, LCFS credits values ranged from \$75 to \$150 per tonne of CO_2 equivalent in the 12 months prior to this report (February 2017 to February 2018).

- The mean CI for RNG from animal waste = $-263.96 \text{ gCO}_{2e}/\text{MJ}$
- This credit is relative to the LCFS rating for CARBOB = $99.78 \text{ gCO}_{2e}/\text{MJ}$
- Avoided emissions from RNG relative to CARBOB = $99.78 - (-263.96) = 363.74 \text{ gCO}_{2e}/\text{MJ}$
- Revenue from LCFS credits = $0.04579 \text{ \$/MJ} = \$48.31/\text{MMBTU}$ (on LHV basis) = $\$43.9/\text{MMBTU}$ (on HHV basis)⁷

Alternatively, assume we are producing biomethane from landfill gas.

- Mean CI for RNG from landfill gas (Row 3 From) = $48.08 \text{ gCO}_{2e}/\text{MJ}$
- Avoided emissions from RNG relative to CARBOB = $99.78 - 48.08 = 51.7 \text{ gCO}_{2e}/\text{MJ}$
- Revenue from LCFS credits = $0.00651 \text{ \$/MJ} = \$6.87/\text{MMBTU}$ (on LHV basis) = $\$6.2/\text{MMBTU}$ (on HHV basis)

As we can see, in the case of animal waste digestion, the resulting LCFS credits are extremely valuable due to the fact that animal waste digesters receive credit for avoiding methane emissions naturally generated from stagnant animal waste ponds.

6.4 Economics of alternatives to pipeline transportation

Alternative uses for biogas exist which may be economically superior to pipeline addition and provide similar environmental benefits. In some cases, it may be more economic to partially upgrade biogas and transport by dedicated pipeline to a large consumer. This strategy avoids the large upgrading costs associated with meeting pipeline specifications but results in similar GHG emissions reductions as fossil natural gas is displaced. Biogas can also be upgraded for use in on-site CNG vehicle refueling. Another alternative to upgrading biogas to biomethane for pipeline injection is to use biogas for on-site energy needs (e.g. heating for buildings and agricultural processes) or for supplying electricity

7. Note that RIN credits under the RFS are measured on Higher Heating Value (HHV basis) while the LCFS emissions intensities on a Lower Heating Value basis. We therefore, convert LCFS revenues to a HHV basis under the assumption that $\text{HHV} = 1.1 * \text{LHV}$.

to the grid. While local air quality constraints may limit the applicability of this strategy, several technologies — such as gas turbines, reciprocating engines, and fuel cells — can be used derive electricity from biogas. In this use-case the biogas will act as a substitute for the fuel that would otherwise have been used to generate the electricity; in California the likely substitution is for natural gas. While there will be limits to on-site demands, any electricity generated in excess of on-site load can be sold to the electric grid once a sufficient interconnect is established. There could be a variety of circumstances under which either of these alternative uses of biogas makes more economic sense, each displacing nearly one MMBTU of natural gas with one MMBTU of biomethane.

Similarly, when biogas is upgraded, biomethane entering the common-carrier pipeline acts as a 1:1 substitute for natural gas. This is typically the preferred pathway for the developer, due to the substantial incentives for biomethane used in transportation. If the biomethane can achieve pipeline access, it can be contractually designated for transportation end-use at some off-site location and qualify for the LCFS and RFS credits described above. However, even if biomethane is notionally used for transportation, the biomethane acts as a substitution for natural gas, not diesel fuel, as it is unlikely this pathway will result directly in the deployment of CNG vehicles. Thus, the greenhouse gas impacts of biomethane injected into a pipeline and used for transportation are identical to the greenhouse gas impacts of biogas used for any other nominal end-use which displaces natural gas.

The current value of the Federal and State incentives far exceeds the market value of the biomethane. However, under the current regulatory rules, “medium BTU” or partially-upgraded biogas does not qualify for credits. As such, these incentives unintentionally bias biogas projects toward upgrading and injection of biomethane to the pipeline, even when other uses may be a more economical way to decrease carbon emissions. If these options were on a level playing field, with equivalent incentives, there may be more efficient ways to allocate capital to achieve greater environmental benefit for every dollar. However, the most profitable option will depend on the upgrading costs and the potential revenue streams.

Conclusion 8: An important question for the State of California is under what conditions biogas should be upgraded to biomethane and the biomethane transported on common-carrier pipelines. An alternative is to use upgraded biogas (not meeting all pipeline standards) or biomethane on-site, typically for generating electricity.

Under the plausible assumption (and anecdotal evidence) that on-site energy demand for heating and electricity is unlikely to be large enough to justify large capital investments in such technologies, we focus on the economics of exporting electricity from biogas to the grid. Table 17. Illustrative calculation of economics of conversion of biogas to electricity for grid supply. is an illustrative calculation of the economics of grid-scale electricity production from biogas.

Table 17. Illustrative calculation of economics of conversion of biogas to electricity for grid supply.

Parameter	Value	Units	Value converted to \$/MMBTU	Source or Notes
Heat rate of biogas plant	7500	BTU/kWh		<i>a</i>
Levelized cost of converting biogas to electricity	0.035	\$/kWh	4.7	<i>b</i>
Price received for electricity - avoided cost basis	0.045	\$/kWh	6.0	<i>c</i>
RFS electricity to fuel RIN equivalence	22.6	kWh/RIN		<i>d</i>
RFS D3 RIN price	2.45	\$/RIN		<i>e</i>
Revenues from D3 RINs	0.108	\$/kWh	14.5	<i>f</i>
LCFS credit revenues	-	-	6.87–48.3	<i>g</i>
Cap and trade credit price	15	\$/MTCO ₂ e		<i>h</i>
Cap and trade emission credit for biogas	66	gCO ₂ e/MJ		<i>i</i>
Cap and trade credit revenues	-	-	0.9	<i>j</i>

a - Based on average heat rate for natural gas reported in https://www.eia.gov/electricity/annual/html/epa_08_01.html

b - Derived by subtracting out fuel cost from the levelized cost for natural gas power plants (examined during peer review).

c - The electricity price received is based on adding up the energy cost portion and the avoided RPS portions of the average of monthly avoided cost of electricity. <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442454810>

d - <https://www.law.cornell.edu/cfr/text/40/80.1415>

e - <https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel>

f - <https://www.ecoengineers.us/>

g - See LCFS calculations: higher value for animal waste and lower value for landfill. This is contingent on establishing that the electricity is being used for transportation.

h - California Cap and trade credit price dashboard <http://calcarbondash.org/>

i - <https://www.epa.gov/lmop/upgrading-landfill-gas-pipeline-gas-and-vehicle-fuel-webinar>

j - $15 \text{ } \$/\text{MTCO}_2\text{e} * 66 \text{ gCO}_2\text{e}/\text{MJ} * 3.6/3412 \text{ MJ}/\text{BTU} * 1\text{e}-6 \text{ MT}/\text{g} * 1\text{e}6 \text{ BTU}/\text{MMBTU} = 0.9 \text{ } \$/\text{mmBtu}$

We can now compare the economics of biogas use for biomethane production vis-à-vis electricity production. Because the cost of producing biogas is common to either of these applications, we compare the gross revenues, or revenues with cost of gas production excluded.

Table 18. From Section 6.3, upgrading biogas to biomethane for pipeline injection entails the following cost and revenue streams.

Description	Cost or Revenue
Mean levelized cost of upgrading to biomethane (990 BTU/scf)	\$5/MMBTU-\$18/ MMBTU
Mean levelized cost of upgrading to biomethane (970 BTU/scf)	\$4/MMBTU-\$13/ MMBTU
Selling price of natural gas	\$3/ MMBTU
Gross revenue from upgrading prior to credits (990 BTU/scf)	\$-2/MMBTU to -15/MMBTU
Gross revenue from upgrading prior to credits (970 BTU/scf)	\$-1/MMBTU to -10/MMBTU
Revenues from D3 RINs under RFS	\$28.7/ MMBTU
Revenues from LCFS credits	\$6/ MMBTU to \$48/ MMBTU

Description	Cost or Revenue
Total revenues from RFS D3 RINS and LCFS credits	\$35/ MMBTU to \$77/MMBTU
Gross revenues from upgrading for pipeline injection (990 BTU/scf)	\$20/MMBTU to \$75/MMBTU
Gross revenues from upgrading for pipeline injection (970 BTU/scf)	\$25/MMBTU to \$76/MMBTU

In other words, as long as costs not considered herein do not exceed \$20/MMBTU when upgrading biomethane to 990 BTU/scf, and do not exceed \$25/MMBTU when upgrading biomethane to 970 BTU/scf, upgrading would yield positive profits. Costs not considered here include: the cost of producing raw biogas; natural gas pipeline extension costs; biomethane quality measurement equipment; off-gas treatment equipment; transformers; switchgear; buildings; interconnecting piping and electrical, civil work; mechanical engineering; permitting; land costs; legal costs; license costs; project management; commissioning services; spares; and taxes. The rationale for not estimating these additional costs is that these are unaffected by the HV specification, which is the scope of this work.

Table 19. From Section 6.4, conversion of biogas to electricity entails the following cost and revenue streams.

Description	Cost or Revenue
Levelized cost of conversion to electricity	\$4.7/MMBTU
Price received for electricity (at avoided cost to utility)	\$6.0/MMBTU
Gross revenue prior to credits from regulations	\$1.3/MMBTU
Revenues from D3 RINs under RFS	\$14.5/MMBTU
Revenues from LCFS credits (requires proving transportation use)	\$6 to \$48/MMBTU
(or)	(or)
Revenues from cap and trade credits	\$1/MMBTU
Total revenues from RFS D3 RINs and LCFS credits	\$21/MMBTU to \$63/MMBTU
Gross revenues from electricity production	\$22/MMBTU to \$64/MMBTU

Finding: Financial incentives through the California Low Carbon Fuel Standard (LCFS) and the Federal Renewable Fuel Standard (RFS) programs can be a factor of up to 18 times greater than the commodity value of the biomethane itself. Both the LCFS and RFS programs have volatile prices; thus investments are subject to substantial regulatory risk.

Finding: Biomethane producers can stack financial incentives; they can receive both the financial incentives of the LCFS and those of the RFS if it can be demonstrated that the biomethane is used for transportation. If it is used for purposes other than transportation, neither incentive is available. Stacking may result in total magnitude of regulatory incentives greater than initially intended by either the State of California or the United States government.

Conclusion 9: The differential treatment under the Federal Renewable Fuel Standard program creates a substantial market distortion away from electricity generation and toward direct use of biomethane. In addition, if CARB regulations allow electricity to obtain only cap-and-trade credits rather than LCFS credits, that regulatory difference adds an additional substantial financial market distortion away from electricity generation.

Recommendation 8: State and Federal agencies should examine whether the substantial differences in incentives for various uses of biogas and biomethane are consistent with the State and Federal policy intentions.

A comparison of the economics of upgrading to biomethane for pipeline injection vis-à-vis exporting electricity to the grid suggests the following:

1. In the absence of any regulatory incentives such as the credits from RFS and LCFS, upgrading to biomethane for pipeline injection is costlier than consuming it on site for electricity production.
2. The regulatory incentives under the RFS and LCFS, each taken alone and certainly together, exceeds the market value of biomethane or electricity from biogas by more than an order of magnitude.
3. Under the RFS, biomethane generates twice the amount of RINs, and therefore revenues, relative to electricity production. Whereas each MMBTU of biomethane generates 11.73 (D3) RINs (see Section 6.3.1), each MMBTU of biogas converted to electricity generates only 5.9 (D3) RINs (From Table 17. Illustrative calculation of economics of conversion of biogas to electricity for grid supply. above, 22.6 kWh/RIN and 7500 BTU/kWh = > 5.9 RINs/ MMBTU).
4. Unlike the RFS, the LCFS treats all final energy products alike. However, biogas-to-electricity developers need to establish a clear link from electricity generation to its use for transportation to benefit from the substantially higher revenue under LCFS, whose carbon price (\$126/MTCO_{2e}) is currently more than eight times the carbon price of cap and trade credits (\$15/MTCO_{2e}).
5. Taking a closer look at the revenues from regulatory incentives, we can compute the cost of avoided GHG emissions in \$/MTCO_{2e} avoided. The implicit carbon price under the RFS varies substantially depending on the source of biomethane. One MMBTU of biomethane offsets one MMBTU of natural gas, but whereas an MMBTU of biomethane from animal waste used has a life cycle carbon intensity of -0.279 MTCO₂/MMBTU⁸, natural gas emits 0.06 MTCO_{2e}. Therefore, each MMBTU of

8. From the LCFS discussion in Section 6.3.2: -263.90 gCO_{2e}/MJ = -0.279 MTCO_{2e}/MMBTU.

biomethane from animal waste avoids 0.34 MTCO_{2e} ($= -0.06 - 0.279$). With each MMBTU generating \$29 in revenues, the implicit carbon price of animal waste biomethane using D3 RIN is \$85/ MTCO_{2e} . On the other hand, assuming an MMBTU of biomethane from wastewater sludge has a lifecycle carbon intensity of 0.02 MTCO_{2e} , it only displaces 0.04 MTCO_{2e} per MMBTU. The implicit carbon price in this case jumps to \$718/ MTCO_{2e} , which greatly exceeds the Federal estimate of the Social Cost of Carbon⁹. Adding the value of the LCFS credits (\$126/ MTCO_{2e}), the total regulatory cost of carbon avoided becomes \$211 and \$835/ MTCO_{2e} depending on the biogas source.

6. Likewise, the carbon price under the LCFS also exceeds the Federal estimate of the Social Cost of Carbon. However, the LCFS does not suffer from the shortcoming described above for the RFS because there isn't a different implicit social cost of carbon for different facilities or resources. Instead, a single carbon price is reflected by price of an LCFS credit.
7. Policymakers need to also contend with the potential issue of "stacking" regulatory incentives, i.e., simultaneously receiving financial benefits under multiple policies. The stacking of credits from multiple regulations could result in total regulatory incentives greater than that intended under any single regulation. It is worth pointing out that biogas to electricity facilities constructed in 2017 are eligible for a production tax credit of \$0.023/kWh (\$3.1/ MMBTU at a heat rate of 7500 BTU/kWh)¹⁰
8. The above analyses and discussions notwithstanding, evaluating the benefits of capturing and using biogas solely in terms of greenhouse gases ignores the environmental benefits, such as local air quality and water quality.

In summary, there is a need for further research into the full social costs and benefits of different pathways to utilization of biogas.

9. The EPA during the Obama Administration estimated the 2020 social cost of carbon dioxide to be well below \$100 per tonne. https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

10. For more details see <https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc>

Chapter 7

Options for dilution of biomethane

Key points

- Dilution of biomethane can be expected to occur within 100–150 pipe diameters if there is a consistent unidirectional flow of NG and properly engineered injection of biomethane.
- Biomethane can locally displace NG, particularly when injected near end-of-network “branches,” and some consumers may receive 100% biomethane.
- Intermittent addition of biomethane can lead to “slugs” of gas with different composition that persist over long pipe distances.
- Arrangements for siphoning off NG from the pipeline, blending with off-spec biomethane, and reinjecting could be feasible in some cases.
- Dilution of biomethane after pipeline addition can occur in situations where the biomethane volume is small in proportion to local consumption; however, this must be evaluated on a case-by-case basis.

Dilution of biomethane is another option to reach compliance with gas quality specifications. Estimates of technically feasible biomethane production in California range from 90–93 bcf/year (Myers Jaffe, 2016; R. B. Williams, Jenkins, & Kaffka, 2015). There is a common misconception that the deviation in gas quality is negligible as biomethane will be a small volumetric contribution to the total supply (less than 5%). However, this presumption ignores the fact that any observed effects of biomethane addition to the pipeline will be highly localized near the point of addition. The global average has little significance in the context of ensuring acceptable gas quality.

With this understood, there are two strategies of how this dilution might be implemented. The first is removing a slip stream of NG from the pipeline, actively mixing this with the non-compliant biomethane, and reinjecting the product gas back into the pipeline. The second is adding non-compliant biomethane directly to the pipeline such that it will be diluted with NG already flowing in the pipe, so that the resulting mixture will meet gas quality specifications before it arrives at any downstream consumers. Both of these strategies will require an understanding of the reasonable expectation for mixing to occur under different circumstances.

Mixing of gases in pipes has been studied for decades (Etchells & Meyer, 2004). The rate of mixing strongly depends on the Reynolds number, Re . The Re is a dimensionless parameter

that indicates the flow regime (laminar, turbulent, or transition) that can be expected to be present in a flowing fluid system such as a pipe. The Reynolds number is defined as

$$Re = \frac{\rho DV}{\mu}$$

Where ρ is the density of the fluid, D is the diameter of the pipe, V is the velocity of the fluid, and μ represents the dynamic viscosity of the fluid (in appropriate units to ensure unit cancellation). At standard temperature and pressure conditions and for the range of pipes and flow velocities seen in the United States, it is expected that gas flow in NG networks is nearly always turbulent (Etchells & Meyer, 2004). Thus, equations for turbulent mixing are appropriate.

Empirical observation and simulations show that complete pipeline mixing for centerline injection and turbulent flows occurs after 50–100 pipeline diameters (Ger et al., 1976; Gray, 1986). For example, Etchells et al. suggest that center-line injection under turbulent flow ($Re = 77,000$) will dilute and mix completely at a mixing length of approximately 60 pipe diameters (Etchells & Meyer, 2004). Side injection is expected to take approximately twice the pipe length as centerline injection to achieve the same mixing (Ger et al., 1976).

For tee-injection¹, the system can be engineered to ensure a certain mixing length by varying the flow velocity and diameter of the jet inlet so that the injection stream has enough momentum to fully cross the stream of gas in the pipeline. As a worst-case scenario, when the momentum is low, the stream acts as a sidewall injection and will require a mixing length of 50–100 pipe diameters (Forney and Lee, 1982). If the point of injection is an angled junction, there is the possibility of stable swirl patterns which lengthen the requisite mixing length (Etchells & Meyer, 2004).

In 2007, the National Energy Technology Laboratory conducted research on natural gas quality and interchangeability in anticipation of increased LNG imports and addition to the NG pipelines (Driscoll, Richards, Huckaby, & Eggenspieler, n.d.). This analysis, using both Reynolds Averaged Navier-Stokes simulations and a Large Eddy Simulation, computationally found mixing lengths of 100 pipe diameters for steady-state LNG injection into pipelines carrying NG. However, they found that transient injection can result in abrupt concentration changes (interfaces) that propagate for very large distances (more than 100 km).

There are also options for inserting static or dynamic mixers in the pipeline to disrupt any patterns that have developed and to enhance mixing (i.e., disrupt sidewall channeling).

1. Tee-injection is when the gas is added to the pipeline at a 90-degree angle with respect to flow direction.

However, these are believed to be most beneficial in situations with laminar flows and are thus less useful for natural gas mixing applications. The use of static mixers incurs a pressure drop that can add to the costs of compression (Etchells & Meyer, 2004).

The above evidence suggests that if the mixing is engineered properly, the length required for the biomethane to become a homogenous mixture with the pipeline natural gas can be managed for both active mixing and passive pipeline dilution. However, the above discussion is only relevant when there is a consistent, unidirectional flow of NG at the point of biomethane addition. This flow of NG also must be large enough, relative to the amount of biomethane, that the mixture will remain in compliance with gas quality specifications.

Although under certain circumstances, pipeline dilution (after injection) could allow biomethane to be safely used after mixing with NG in the pipeline, this method is debated because of concerns that dilution could be unreliable and lead to unpredictable changes in the quality of gas received by consumers.

There are two main challenges associated with relying on dilution to meet pipeline specifications:

1. If the amount of biomethane injected is large relative to local consumption, displacement of NG may occur with minimal blending.
2. Passive mixing may not occur reliably in practice, due to transient or discontinuous injection, causing “slugs” of out-of-specification gas to arrive erratically at end consumers.

The first concern of displacement is an unavoidable aspect of the dynamics of gas flow in a pipeline network where injection is large relative to consumption. NG networks — especially nearer to end-of-network branches of distribution infrastructure — are generally more complex than an idealized and consistent one-way flow of NG into which biomethane would be added. Flow at a location is governed by relative injection and consumption at nearby pipeline nodes. As such, large volumes of biomethane injection into a network with low consumption volumes will necessarily displace local NG and result in out-of-specification gas at consumers near the injection point.

illustrates these two cases. In the left case, injection of biomethane (darker color) at point B occurs in small volumes relative to inflow (point A) and combined outflow (point C). In this case, dilution may be a viable option for avoiding out-of-specification gas at consumers downstream of point C. In the right case, injected biomethane volumes are large compared to local consumption. Before biomethane injection, gas enters the local network at point A*. Injection of biomethane at point B* begins and is large relative to local consumption. Biomethane thus displaces local gas, displacing NG from consuming points C* and D* and reversing the flow direction at point A*.

Displacement of NG by biomethane is a site-specific concern which must be evaluated on a case-by-case basis when a utility approves injection at a location. If injection volumes are suitably large, dilution cannot be relied upon as a reliable mechanism to meet gas quality specifications, and the gas injected must be required to meet any specifications that apply to end user gas quality. The simulations and case studies below in Chapter 7 show examples of these phenomena.

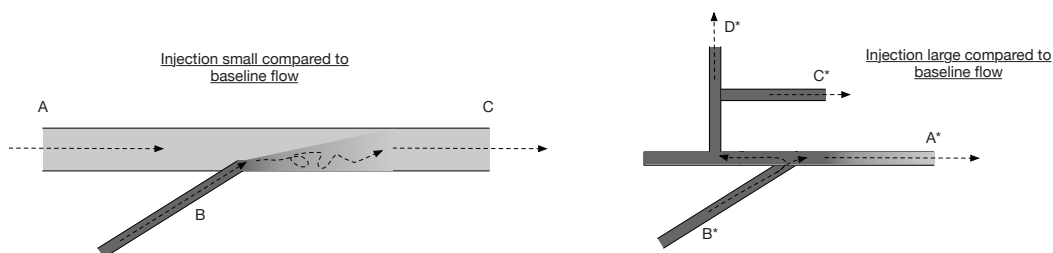


Figure 17. The effect of injection volume on gas dilution. Injection that is small compared to baseline flow (left) or large relative to baseline flow (right) can have very different implications for mixing and displacement.

Reliance on passive mixing can cause gas quality issues even in cases where injection volumes cause flow to be more similar to the first case above. For example, the two streams could be unreliably mixed, due to seasonal variations in demand, intermittent addition of biomethane, or unexpected pipeline outages upstream. All of these could cause slugs of gas to persist if passive mixing is relied upon. Figure 18 illustrates passive and active mixing. In (left), gas is injected into the main stream at point B and turbulent flow provides natural mixing of the two streams, such that all specifications are met by point C when the gas streams are well mixed.

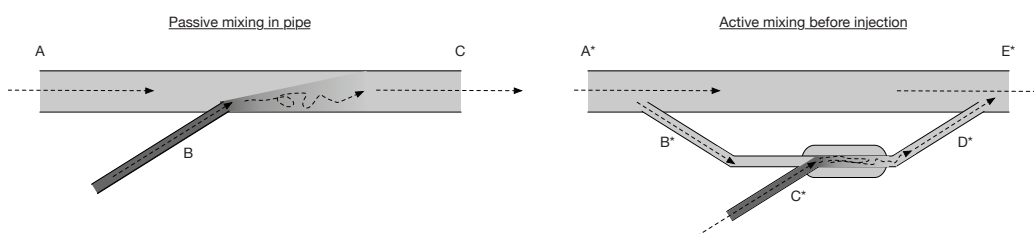


Figure 18. Two methods of mixing biomethane with NG. Passive mixing (left) relies on natural turbulence to mix two gas streams. Active mixing (right) removes a stream of gas from the main flow and actively mixes it before injecting on-specification gas back into the pipe.

As noted above, in some cases this passive mixing is ineffective, resulting in slugs of out-of-specification gas. In (right), a slipstream of gas is removed from the main flow and actively mixed before injecting the mixed stream back into the pipe.

It is recommended that regulatory bodies act to ensure that such active mixing can be done in a fair, non-punitive financial arrangement. For example, ensuring a biomethane producer is not charged for NG removed, mixed, and re-introduced to the pipe in order to meet specifications.

Chapter 8

Simulation and analysis of regional gas pipeline networks

Key points

- There could be non-negligible impacts of widespread biomethane development on HV delivered to consumers in certain regions of California.
- Rural regions of the pipeline system with low NG consumption and high dairy biomethane potential, such as Hanford, could become net exporters of biomethane for much of the year.
- For larger urban gas networks, most effects will be seen in localized areas of the system due to the larger NG flow rates relative to demand.
- It is incumbent on the utilities to use the data and tools at their disposal to plan for these potential changes in gas system behavior and HV delivered to the consumer.

The addition of a new source of gas to a pipeline will generally alter the composition and HV of gas in the system. In some cases, an influx of gas at new locations in the network can change flow direction and magnitudes from historically observed values. In order to understand the implications of widespread biomethane production in California, it is necessary to model the NG transmission and distribution system with a geographically-resolved pipeline network simulation tool.

8.1 Review of gas network simulation literature

Steady-state analysis of pipeline networks has been modeled in academic and industry studies to optimize pipeline operations, minimize compressor energy usage, and plan for capacity additions, etc. These models can also be used to understand the effects of distributed injection of biomethane.

In this work we apply the classic approach of Osiadacz (Osiadacz, 1987). Osiadacz leverages graph theory methods to simulate both steady-state network flows, and transient solutions. The academic literature contains many examples of implementation of these methods and variations. (Herrán-González, De La Cruz, De Andrés-Toro, & Risco-Martín, 2009; Woldeyohannes & Majid, 2011). Most relevant to this work, Abeysekera et al. (2014) developed a steady-state simulation to model distributed injection of alternative gases such as hydrogen and biomethane (Abeysekera, Rees, & Wu, 2014).

Such simulation tools are also used by LDCs in system planning. LDCs have access to full consumption and flow meter data of their system and can use this in concert with detailed knowledge of network topology to build sophisticated hydraulic models. These hydraulic models can inform, for example, decisions regarding whether a pipe has enough capacity to transport more gas. For example, hydraulic modeling efforts by SoCalGas were independently evaluated in the wake of the Aliso Canyon failure to ensure that SoCalGas would be able to meet ramping natural gas demands during the summer of 2017 (Backhaus, Walker, & Ewers, 2017).

8.2 Regional gas pipeline network simulation case studies

To illustrate graphically the questions raised above, we developed models of transmission gas networks for three California regions: San Diego, Hanford, and San Francisco/Bay Area. Each region was represented as a network of supply/demand centers (nodes) and pipelines (branches).

Monthly NG consumption data for core demands (residential, commercial, industrial, and agriculture) by zip code were acquired from PG&E and SoCalGas websites [therms/month]. Zip codes with few customers are aggregated by the utilities due to privacy concerns, so not all zip codes in modeled areas have reported data. Prospective biomethane production site locations (longitude/latitude) and potential production amounts [MMBTU/yr] were collected from the dataset of Jaffe et al. (Myers Jaffe, 2016). Finally, NG consumption for electric power and combined heat and power generation in 2016 were acquired from EIA Form 860 [plant location and type] and Form 923 [mcf/month] datasets. EIA NG consumption for power is allocated to zip code with the nearest geographic centroid.

Pipeline data were digitized from a CEC map of the California NG transmission pipeline system (CEC, 2018a). The digital CEC map was georeferenced over a zip code map of California in ArcMap 10.5.1. Polyline shapefiles were created by digitizing the pipeline image for each selected region. The CEC does publish a GIS shapefile of the transmission pipelines in California (CEC, 2018b), but those data are more detailed than required to match the spatial scale of publicly-available NG consumption data.

Zip code level gas demand is modeled as removed from the pipeline at the pipeline location nearest the zip code centroid. This assumption was required because detailed distribution-level pipeline network maps are not publicly accessible. Prospective biomethane injection is modeled as occurring at the point on the transmission pipeline closest to the location of the biomethane production facility. While addition of biomethane to the nearest low-pressure distribution line may be more economic for the producer, detailed distribution-level pipeline network maps are not available. We make the simplifying assumption that the transmission pipeline will be able to accept injection of all prospective biomethane at the pipe location nearest the production facility.

The pipeline network shapefile was translated into a directed graph, defined by a branch-nodal incidence matrix. The rows of this matrix each represent a node, and the columns each represent a branch. The matrix, \mathbf{A} , is sparsely populated with 1, 0, and -1 values. If a 1 exists in element \mathbf{A}_{ij} this indicates that branch j enters node i . If a -1 exists in element \mathbf{A}_{ij} , then branch j leaves node i . If a 0 exists in \mathbf{A}_{ij} , then no intersection of branch j occurs with node i (most common). See Figures in Section 8.2 for a visual representation of these connected graphs.

The system was assumed to be isothermal and in steady-state. The average continuous natural gas consumption [kW] is imposed at each zip code demand node and the average continuous biomethane supply from each prospective production site [kW]. Due to lack of seasonal data, biomethane production is assumed to be constant throughout the year. One slack node is required, which represents unconstrained flow into system of conventional NG. The slack node allows the model to balance supply and demand for each month.

The pressures at each node and the flows through each branch are variables in a system of nonlinear equations that are solved to determine the steady state flows of gas. A flow equation exists for each branch and a conservation of mass equation exists for each node (except for the slack node). The flow equations dictate the physics of flow of a fluid in a pipe between two points with a pressure difference. For our models: flow, Q [m³/hr] is a function of pressure; P [kPa]; the length, L [km]; friction factor, f ; and diameter of the pipe, D [mm]; as well as the temperature, T [K]; compressibility, Z ; and specific gravity, G , of the gas:

$$K_{ij}Q_{ij}^2 = P_i^2 - P_j^2$$

$$K_{ij} = C \frac{f G Z T}{D^5} \left(\frac{P_n}{T_n} \right)^2 L$$

P_n and T_n represent the pressure and temperature at normal conditions (101.325 kPa and 293.15 K). C is a unit conversion constant equal to 4.3599×10^8 .

The conservation-of-mass equations ensure, for every node, that the sum of all flows into a node (Q_{ji}), including any injected supply (S_i), equal the flows out of the node (Q_{ij}) and any associated demands (D_i).

$$\forall i = 1:N \sum_{j=1}^J Q_{ji} + S_i - \sum_{j=1}^J Q_{ij} - D_i = 0$$

Newton-Raphson's method was implemented to solve the equations by driving the residual form of these equations to zero. Due to quadratic terms, the model may converge on a non-physical solution, in which case the simulation is run again with a randomized initial guess for the pressure and flow variables until the physical solution is found. For all simulations the HV of baseline NG was assumed to be 1050 BTU/scf and the biomethane HV was assumed to be 972 BTU/scf. Results for each regional case study are presented visually below and can be found numerically in Appendix F.

8.2.1 San Diego

The network for the San Diego region includes all transmission pipes in the San Diego Gas and Electric (SDG&E) service territory. The flow at the U.S-Mexico border is set to the average monthly transactions at the Otay Mesa border crossing (SoCalGas, 2018). All biomethane sources from the Jaffe et al. study within the modeling region are considered as possible biomethane sources. In our base case, we assume that all biomethane sources 10 km of the pipeline are constructed and operate at estimated production volumes.

The results in Figure 19. San Diego regional gas network flows evaluated for January, April, July, and October 2016. Stronger natural gas demands mean that the biomethane fractions received at each zip code node are smaller and resultant HV deviation is confined. Base map from Google Earth. show base case simulations covering historical months of January, April, July, and October 2016. Injection sites are designated by white circles. The rest of the nodes in the network represent demand off-takes for zip code centroids or junction nodes (at which pipes “split” but there is no demand or supply). The HV received at each node is represented by color (dark red is NG, dark blue is pure biomethane).

The San Diego case illustrates that seasonal demand trends may have non-negligible effects on the gas received by the consumer. Under our base case 100% biomethane build-out scenario, most of the zip-codes could be expected to receive nearly 100% NG during most of the year. However, a handful of regions at the radial ends of the network may see nearly 100% biomethane during the spring months of low demand. Appliances in this region must be able to accept such deviation in gas quality over the course of the year, and depending on the site, dilution may not be a viable option for compliance.

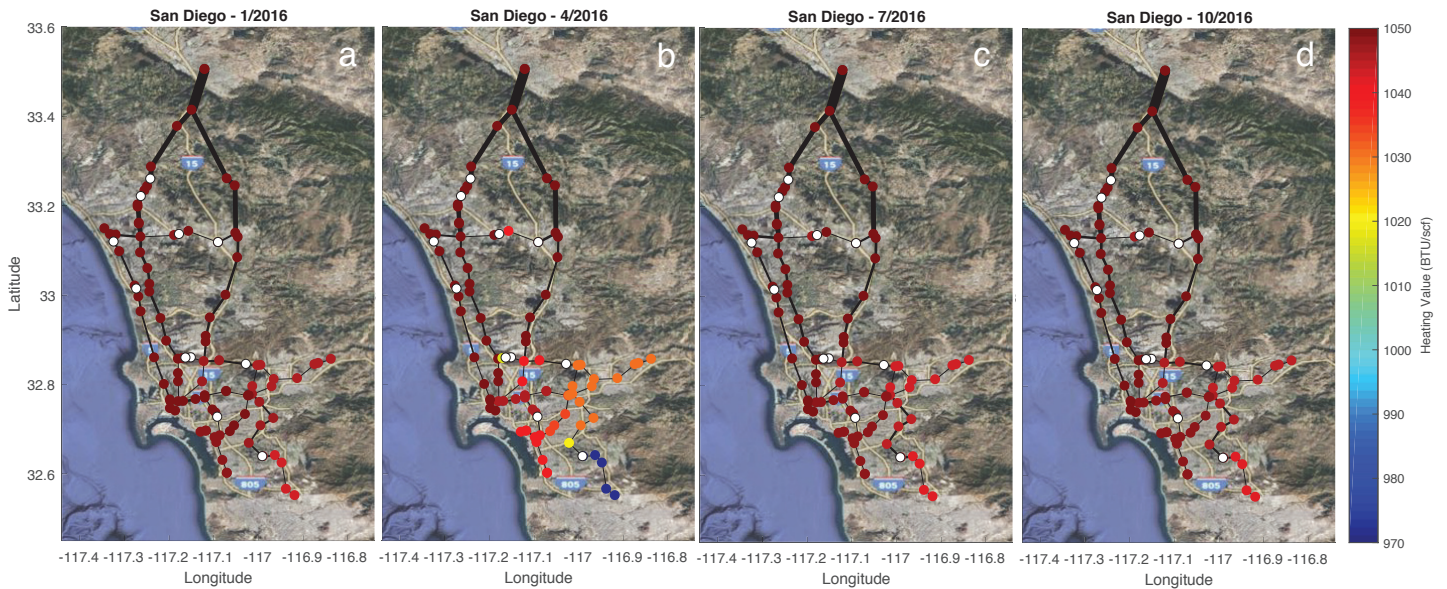


Figure 19. San Diego regional gas network flows evaluated for January, April, July, and October 2016. Stronger natural gas demands mean that the biomethane fractions received at each zip code node are smaller and resultant HV deviation is confined. Base map from Google Earth.

8.2.2 Hanford

The Hanford case area is a rural area with numerous dairy farms that could act as sources of biomethane. Because of the low population density, there is comparatively less local demand for NG. Under a 100% biomethane build-out scenario as implemented in the San Diego and South Bay Area cases, the biomethane supply would overwhelm 2016 regional demand and flow at the slack node would be negative, indicating biomethane exports from the region. As such, we examine partial build-out of biomethane projects. Figure 20. Hanford regional gas network flows evaluated for June and December 2016. Note the small inflow of natural gas from outside of the regional subdivision, as almost all of the local demands are satisfied with biomethane provided from the numerous potential dairy farm production sites. displays the results for June and December 2016 under 10% and 50% development scenarios. These scenarios were generated by randomly selecting in each case to build ~10% or ~50% of the potential biomethane sites.

The Hanford example shows a region where significant deviation from historical pipeline behavior could be seen due to the widespread addition of biomethane and small local demand. Widespread build-out of biomethane in Hanford could result in this region of the network being a net producer for multiple months out of the year and the local transmission system being essentially 100% biomethane.

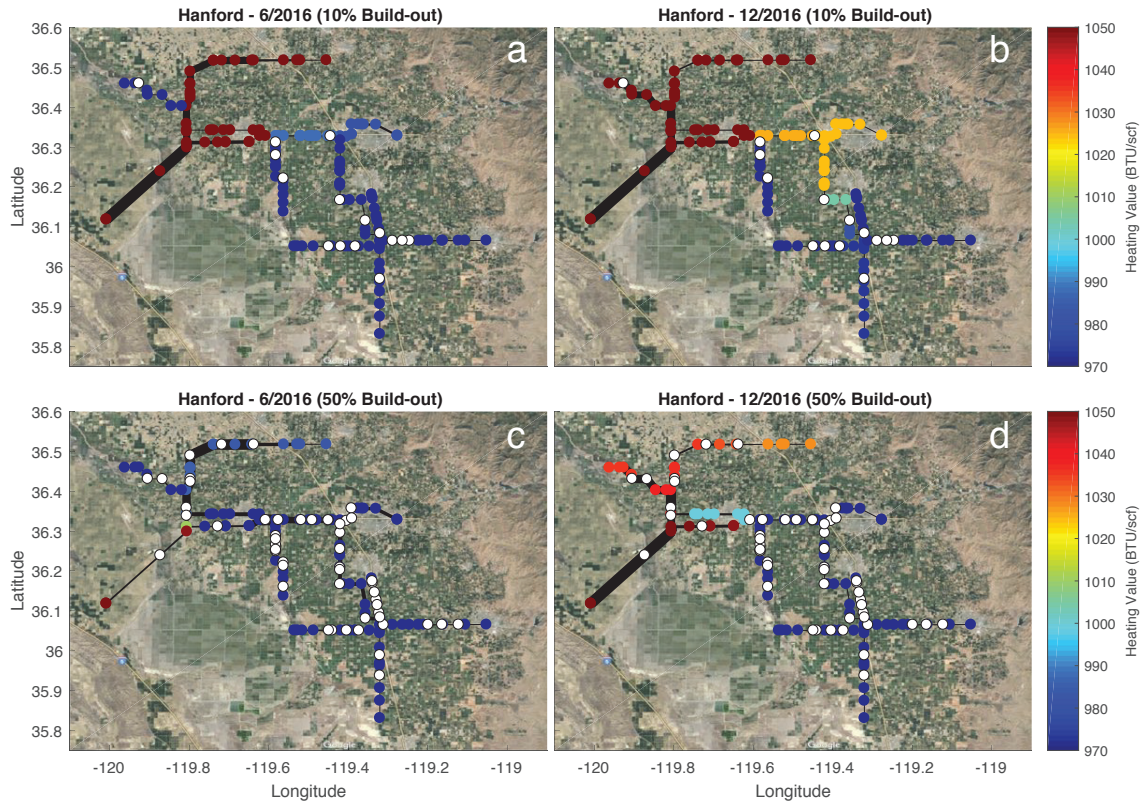


Figure 20. Hanford regional gas network flows evaluated for June and December 2016. Note the small inflow of natural gas from outside of the regional subdivision, as almost all of the local demands are satisfied with biomethane provided from the numerous potential dairy farm production sites.

8.2.3 San Francisco / South Bay Area

The South Bay Area case study shows that large year-round demand can minimize overall gas quality deviation incurred by the addition of biomethane. Figure 21. Bay Area regional gas network flows evaluated for January, April, July, and October 2016. shows results for the 100% biomethane addition base case, again for January, April, July, and October 2016. We see that very few nodes could receive 100% biomethane due to their position on branches adjacent to potential production sites. However, the majority of zip codes are expected receive gas above 1000 BTU/scf year-round.

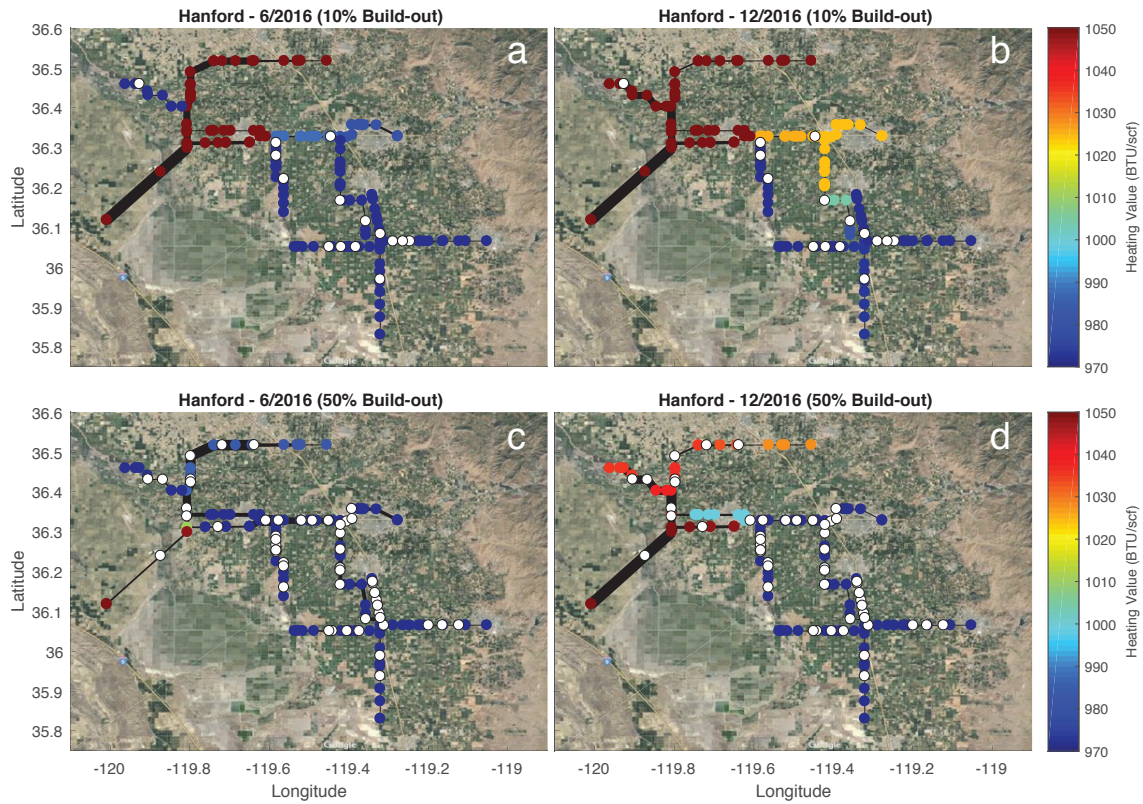


Figure 21. Bay Area regional gas network flows evaluated for January, April, July, and October 2016.

8.3 Synthesizing conclusions

The case studies explored above suggest that there could be non-negligible impacts of a widespread biomethane build-out in certain regions (e.g., Hanford region). Other agricultural regions in California could see similar results. For larger urban gas networks, most effects will be seen in localized areas of the system due to the larger NG flow rates relative to demand (e.g., San Francisco/South Bay Area). In these cases, it is incumbent on the utilities to use the data and tools at their disposal to plan for these potential changes in gas system behavior and HV delivered to the consumer.

Works Cited

- Abatzoglou, N., & Boivin, S. (2009). A review of biogas purification processes. *Biofuels, Bioproducts and Biorefining*. <https://doi.org/10.1002/bbb.117>
- Abeyskera, M., Rees, M., & Wu, J. (2014). Simulation and analysis of low pressure gas networks with decentralized fuel injection. In *Energy Procedia*. <https://doi.org/10.1016/j.egypro.2014.11.1135>
- AGA. (2009). Natural Gas Contract Measurement & Quality Clauses. *AGA Report-4A*, (4).
- Ajhar, M., Travasset, M., Yüce, S., & Melin, T. (2010). Siloxane removal from landfill and digester gas - A technology overview. *Bioresource Technology*, 101(9), 2913–2923. <https://doi.org/10.1016/j.biortech.2009.12.018>
- Altmann, J., & Ripperger, S. (1997). Particle deposition and layer formation at the crossflow microfiltration. *Journal of Membrane Science*, 124(1), 119–128. [https://doi.org/10.1016/S0376-7388\(96\)00235-9](https://doi.org/10.1016/S0376-7388(96)00235-9)
- Angelidaki, I., Treu, L., Tsapekos, P., Luo, G., Campanaro, S., Wenzel, H., & Kougias, P. G. (2018). Biogas upgrading and utilization: Current status and perspectives. *Biotechnology Advances*, 36(2), 452–466. <https://doi.org/10.1016/j.biotechadv.2018.01.011>
- Application guide, Landfill/Digester Gas Use with the Capstone MicroTurbine. (2004). Capstone Turbine Corporation. [https://doi.org/10.1016/S0026-0576\(00\)83602-8](https://doi.org/10.1016/S0026-0576(00)83602-8)
- ASTMWK52796. (2018). New Test Method for Measurement of Volatile Silicon-Containing Compounds in Gaseous Samples using Gas Chromatography with Spectroscopic Detection. Retrieved February 1, 2018, from <https://www.astm.org/DATABASE.CART/WORKITEMS/WK52796.htm>
- Backhaus, S., Walker, R., & Ewers, M. (2017). Independent Review of Hydraulic Modeling for Aliso Canyon Review of Summer 2017 Assessment.
- Baez, A., & Hill, A. (2014). *Conduct a Nationwide Survey of Biogas Cleanup Technologies and Costs*. Retrieved from www.gastechnology.org
- Bailón Allegue, L., & Hinge, J. (2012). *Biogas and bio-syngas upgrading*. DTI Report.
- Batchelor, G. K., & Shen, C. (1985). Thermophoretic deposition of particles in gas flowing over cold surfaces. *Journal of Colloid And Interface Science*, 107(1), 21–37. [https://doi.org/10.1016/0021-9797\(85\)90145-6](https://doi.org/10.1016/0021-9797(85)90145-6)
- Bauer, F., Hulteberg, C., Persson, T., & Tamm, D. (2013a). Biogas upgrading - Review of commercial technologies. *SGC Rapport*, 270.
- Bauer, F., Hulteberg, C., Persson, T., & Tamm, D. (2013b). Biogas upgrading - Review of commercial technologies. *SGC Rapport*, 83. <https://doi.org/SGC Rapport 2013:270>
- Bora, R., Crippen, K., & Ferrer, M. (2013). Phase II : Assessing Acceptable Siloxane Concentrations in Biomethane, (21103).
- CalEPA. (2013). *Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline*. Available at: https://www.arb.ca.gov/energy/biogas/documents/FINAL_AB_1900_Staff_Report_&_Appendices_%20051513.pdf. Last access August 2017. Retrieved from <http://www.arb.ca.gov/energy/biogas/biogas.htm>
- CARB. (2018). *Weekly LCFS Credit Transfer Activity Report 2/26/18 - 3/4/18*.
- Caterpillar G36000- G3300 Fuels. (n.d.).
- CEC. (2018a). California Natural Gas Pipeline. Retrieved from http://www.energy.ca.gov/maps/infrastructure/natural_gas.html
- CEC. (2018b). California Natural Gas Pipeline. Retrieved February 1, 2018, from <https://cecgis-caenergy.opendata.arcgis.com/datasets/california-natural-gas-pipeline?geometry=-123.376%2C32.263%2C-108.072%2C35.455>

- CEN/TC408. (2015). *Natural gas and biomethane for use in transport and biomethane for injection in the natural gas network - Part 2: Automotive fuel specifications*.
- Colorado, A., & Mcdonell, V. (2017). Effect of Variable Fuel Composition on Emissions and Lean Blowoff Stability Performance: Analysis of Nine Industrial Combustion Applications, (April), 45. <https://doi.org/10.13140/RG.2.2.20136.88323>
- CPUC. (2006). Decision 06-09-039.
- CPUC. (2014). Decision 14-01-034, 8.
- Crippen, K., Wiley, K., & Bora, R. (2012). *Guidance Document for the Introduction of Landfill-derived Renewable Gas into Natural Gas Pipelines*.
- CRNG. (2016). *Revisiting CPUC AB 1900 Biomethane Pipeline Injection Regulations to Remove Barriers Preventing Biomethane Project Development in California*.
- D’Zurko, D., & Benson, C. (2015). Gas Interchangeability Study and Resulting NYSEARCH RANGE™ Model for Installed Residential Appliances, 0–20.
- Damodaran, A. (2007). Strategic Risk Taking - A framework for risk management. Retrieved from https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf
- Dewil, R., Appels, L., & Baeyens, J. (2006). Energy use of biogas hampered by the presence of siloxanes. *Energy Conversion and Management*, 47(13–14), 1711–1722. <https://doi.org/10.1016/j.enconman.2005.10.016>
- Driscoll, D. J., Richards, G. A., Huckaby, E. D., & Eggenspieler, G. N. (n.d.). LNG Interchangeability/Gas Quality: Results of the National Energy Technology Laboratory’s Research for the FERC on Natural Gas Quality and Interchangeability.
- Electrigaz Technologies Inc. (2011). Economic Study on Renewable Natural Gas Production and Injection Costs in the Natural Gas Distribution Grid in Ontario - Biogas plant costing report, (September).
- Engler, D., Feltham, G., & Tweedie, J. (2012). Standing Committee on Operations Biomethane Task Force Biomethane Guidelines for the Introduction of Biomethane into Existing Natural Gas Distribution & Transmission Systems, (February).
- EPA. (2016). *Cellulosic Waiver Credit Price Calculation for 2016 (EPA-420-B-15-092, November 2015)* (211). Retrieved from www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMA_EPM0_PBR_NUS_DPG&f=M.
- Estrada Jr., A. B. (1996). The Effect of Gas Composition on Residential Appliance Burner Performance. *Natural Gas Quality & Energy Measurement*.
- Etchells, A. W., & Meyer, C. F. (2004). Mixing in Pipelines. *Handbook of Industrial Mixing*, 391–477. <https://doi.org/10.1002/0471451452.ch7>
- Favre, E., Bounaceur, R., & Roizard, D. (2009). Biogas, membranes and carbon dioxide capture. *Journal of Membrane Science*, 328(1–2), 11–14. <https://doi.org/10.1016/j.memsci.2008.12.017>
- Gaseous Fuel Specification for Waukesha Engines. (2014). GE Power & Water.
- Gersen, S., Visser, P., van Essen, V., Dutka, M., ThM de Hosson, J., & Levinsky, H. (2013). Effects of silica deposition on the performance of domestic equipment. *Proceedings of the European Combustion Meeting*, 2.
- Griffiths, J. C., Connely, S. M., & Deremer, R. B. (1982). *Effect of fuel gas composition on appliance performance*. Chicago, Illinois.
- Hagen, M., & Polman, E. (2001). Adding Gas from Biomass to the Gas Grid, 1–142. Retrieved from <https://mail.google.com/mail/u/0/?ui=2&pli=1%5Cnpapers2://publication/uuid/C6C6C328-6E60-49D6-8898-E49C8038F2A2>
- Hayes, H. C., Graening, G. J., Saeed, S., & Kao, S. (n.d.). A Summary of Available Analytical Methods for the Determination of Siloxanes in Biogas.

- Hernandez, D., Vargas, R., Rodriguez, C., Gibson, A., Haines, D., & Peacock, T. (2017). DRAFT Engineering Analysis Center - Applied Technologies, (August).
- Herrán-González, A., De La Cruz, J. M., De Andrés-Toro, B., & Risco-Martín, J. L. (2009). Modeling and simulation of a gas distribution pipeline network. *Applied Mathematical Modelling*, 33(3), 1584–1600. <https://doi.org/10.1016/j.apm.2008.02.012>
- Interagency Working Group on Social Cost of Greenhouse Gases. (2016). Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. *Interagency Working Group on Social Cost of Greenhouse Gases*, (August), 1–21. <https://doi.org/papers3://publication/uuid/5EDE4E5D-16B6-4352-A898-228FF7881D99>
- Jaffrin, A., Bentounes, N., Joan, A., & Makhlof, S. (2003). Landfill biogas for heating greenhouses and providing carbon dioxide supplement for plant growth. *Biosystems Engineering*.
- John Boesel, C., & Rutledge, B. (2005). WestStart-CALSTART California Biogas Industry Assessment.
- Jones, H. R. N. (1989). *The application of combustion principles to domestic gas burner design*.
- Kramer, U., Ferrera, M., Kühne, H., Moreira, D. C., & Magnusson, I. (2015). Natural Gas / Methane Fuels : European Automotive Fuel Quality and Standardization Requirements. *10th Conference on Gaseous-Fuel Powered Vehicles*.
- Lampe, S. (2006). *Assessment of Fuel Gas Cleanup Systems for Waste Gas Fueled Power Generation*. Palo Alto, California.
- Minutólo, P., Sgro, L. A., Costagliola, M. A., Prati, M. V., Sirignano, M., & D'Anna, A. (2010). Ultrafine particle emission from combustion devices burning natural gas. *Chemical Engineering Transactions*, 22, 239–244. <https://doi.org/10.3303/CET1022039>
- Mokhov, A. V. (2011). Silica Formation From Siloxanes in Biogas : Novelty or Nuisance, 1–17.
- Myers Jaffe, A. (2016). *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*.
- Nair, N., Vas, A., Zhu, T., Sun, W., Gutierrez, J., Chen, J., ... Tsotsis, T. T. (2013). Effect of siloxanes contained in natural gas on the operation of a residential furnace. *Industrial and Engineering Chemistry Research*, 52(18), 6253–6261. <https://doi.org/10.1021/ie400449v>
- Nair, N., Zhang, X., Gutierrez, J., Chen, J., Egolfopoulos, F., & Tsotsis, T. (2012). Impact of siloxane impurities on the performance of an engine operating on renewable natural gas. *Industrial and Engineering Chemistry Research*, 51(48), 15786–15795. <https://doi.org/10.1021/ie302751n>
- Napierska, D., Thomassen, L. C. J., Lison, D., Martens, J. A., & Hoet, P. H. (2010). The nanosilica hazard: Another variable entity. *Particle and Fibre Toxicology*, 7(1), 39. <https://doi.org/10.1186/1743-8977-7-39>
- Network Innovation Allowance Project Status Report. (2017).
- NGC+. (2005). White Paper on Natural Gas Interchangeability and Non-Combustion End Use.
- Ong, M. D., Williams, R. B., & Kaffka, S. R. (2014). DRAFT Comparative Assessment of Technology Options for Biogas Clean-up.
- Ong, M. D., Williams, R. B., & Kaffka, S. R. (2017). Renewable Energy Resource, Technology, and Economic Assessments Appendix H - Task 8: Comparative Assessment of Technology Options for Biogas Clean-Up, 164.
- Osorio, F., & Torres, J. (2009). Biogas purification from anaerobic digestion in a wastewater treatment plant for biofuel production. *Renewable Energy*.
- Palmgren, C., Stevens, N., Goldberg, M., Bames, R., & Rothkin, K. (2010). *2009 California residential appliance saturation survey*.
- Parker, N., Williams, R., Dominguez-Faus, R., & Scheitrum, D. (2017). Renewable natural gas in California: An assessment of the technical and economic potential. *Energy Policy*, 111(September), 235–245. <https://doi.org/10.1016/j.enpol.2017.09.034>

- Persson, M. (2003). *Evaluation of upgrading techniques for biogas*.
- Persson, M., Jonsson, O., & Wellinger, A. (2006). Biogas Upgrading to Vehicle Fuel Standards and Grid Injection.
- PFL Fuel Services. (2014). PFL Weekly RIN Recap, 2012–2013.
- PG&E. (2015). Gas Rule No. 21 Transportation of Natural Gas.
- Pierce, J. L. (2015). Siloxanes and Landfill Gas Utilization. In *MSW Management*.
- Pierre, C., Flottes, E., Favre, A., Raynal, L., Pierre, H., Capela, S., & Peregrina, C. (2016). Techno-economic and Life Cycle Assessment of methane production via biogas upgrading and power to gas technology. *Applied Energy*. <https://doi.org/10.1016/j.apenergy.2016.08.181>
- Pöschl, M., Ward, S., & Owende, P. (2010). Evaluation of energy efficiency of various biogas production and utilization pathways. *Applied Energy*. <https://doi.org/10.1016/j.apenergy.2010.05.011>
- Rasi, S. (2009). *Biogas Composition and Upgrading to Biomethane*. <https://doi.org/978-951-39-3607-5>
- Rawson, M., & Spiegel, L. (2013). Final Project Report Removal of Siloxane and H₂S From Biogas Using Microwave.
- Renewable Fuel Standard Program: Standards for 2018 and Biomass-Based Diesel Volume for 2019, 82 (2017).
- Rue, D., Chudnovsky, Y., Johnson, F., Wagner, J. C., Singer, B. C., Lunden, M. M., ... Carreras-Sospedra, M. (2011). Implications of Natural Gas Interchangeability for California Customers.
- Ryckebosch, E., Drouillon, M., & Vervaeren, H. (2011). Techniques for transformation of biogas to biomethane. *Biomass and Bioenergy*. <https://doi.org/10.1016/j.biombioe.2011.02.033>
- Saber, D. L. (2009a). *Pipeline quality biomethane: North American guidance document for introduction of dairy waste derived biomethane into existing natural gas networks*. Retrieved from http://www.gastechnology.org/market_results/Pages/Dairy-Waste-Biomethane-Interchangeability-Oct2009.aspx
- Saber, D. L. (2009b). *Task 2 Final Report: Laboratory Testing and Analysis*.
- Schweigkofler, M., & Niessner, R. (1999). Determination of siloxanes and VOC in landfill gas and sewage gas by canister sampling and GC-MS/AES analysis. *Environmental Science and Technology*, 33(20), 3680–3685. <https://doi.org/10.1021/es9902569>
- Schweigkofler, M., & Niessner, R. (2001). Removal of siloxanes in biogases. *Journal of Hazardous Materials*, 83(3), 183–196. [https://doi.org/10.1016/S0304-3894\(00\)00318-6](https://doi.org/10.1016/S0304-3894(00)00318-6)
- Singer, B. C. (2006). Natural Gas Variability in California: Environmental Impacts and Device Performance - Literature Review and Evaluation for Residential Appliances.
- SoCalGas. (2005). Gas Quality and Liquefied Natural Gas Research Study.
- SoCalGas. (2015). Rule No. 30 Transportation of Customer-Owned Gas.
- Soreanu, G., Béland, M., Falletta, P., Edmonson, K., Svoboda, L., Al-Jamal, M., & Seto, P. (2011). Approaches concerning siloxane removal from biogas - A review. *Canadian Biosystems Engineering / Le Genie Des Biosystems Au Canada*.
- Sun, Q., Li, H., Yan, J., Liu, L., Yu, Z., & Yu, X. (2015). Selection of appropriate biogas upgrading technology - A review of biogas cleaning, upgrading and utilisation. *Renewable and Sustainable Energy Reviews*. <https://doi.org/10.1016/j.rser.2015.06.029>
- Tansel, B., & Surita, S. C. (2014). Oxidation of siloxanes during biogas combustion and nanotoxicity of Si-based particles released to the atmosphere. *Environmental Toxicology and Pharmacology*, 37(1), 166–173. <https://doi.org/10.1016/j.etap.2013.11.020>
- Turkin, A. A., Dutka, M., Vainchtein, D., Gersen, S., van Essen, V. M., Visser, P., ... De Hosson, J. T. M. (2014). Deposition of SiO₂ nanoparticles in heat exchanger during combustion of biogas. *Applied Energy*. <https://doi.org/10.1016/j.apenergy.2013.08.068>

Turning Waste Into Renewable Natural Gas: Point Loma Wastewater Treatment Plant Case Study - Five Years After Commercial Operation. (2016).

Ullah Khan, I., Hafiz Dzarfan Othman, M., Hashim, H., Matsuura, T., Ismail, A. F., Rezaei-DashtArzhandi, M., & Wan Azelee, I. (2017). Biogas as a renewable energy fuel - A review of biogas upgrading, utilisation and storage. *Energy Conversion and Management*, 150(August), 277–294. <https://doi.org/10.1016/j.enconman.2017.08.035>

Wang, F., Gao, F., Lan, M., Yuan, H., Huang, Y., & Liu, J. (2009). Oxidative stress contributes to silica nanoparticle-induced cytotoxicity in human embryonic kidney cells. *Toxicology in Vitro*, 23(5), 808–815. <https://doi.org/10.1016/j.tiv.2009.04.009>

Weiland, P. (2010). Biogas production: Current state and perspectives. *Applied Microbiology and Biotechnology*, 85(4), 849–860. <https://doi.org/10.1007/s00253-009-2246-7>

Wheless, E., & Pierce, J. (2004). Siloxanes in Landfill and Digester Gas Update.

Williams, E. (2017). Commercial Landfill Gas Energy Projects: Opportunities and Barriers. *Landfill Methane Outreach Program*.

Williams, R. B., Jenkins, B. M., & Kaffka, S. (California B. C. (2015). An Assessment of Biomass Resources in California, 2013 Data. *Contractor Report to the CEC. PIER Contract 500-11-020*, (March), 1–155. <https://doi.org/500-11-020>

Woldeyohannes, A. D., & Majid, M. A. A. (2011). Simulation model for natural gas transmission pipeline network system. *Simulation Modelling Practice and Theory*, 19(1), 196–212. <https://doi.org/10.1016/j.simpat.2010.06.006>

Appendix A

Gaseous fuel interchangeability literature

Residential/Commercial:

American Gas Association/Gas Research Institute (Griffiths et al., 1982)

The American Gas Association (AGA) and the Gas Research Institute conducted a study in 1982 to aid in the determination of whether fuel flexibility evaluation ought to be included in the Z21 series of the American National Standards Institute (ANSI) appliance testing protocols. For the purposes of this investigation, appliances were tuned to operate on a typical adjustment gas and tested on several limit gases as determined by the AGA indices. Limit gas compositions were formulated for lifting (L), yellow tipping (Y), and flashback (H) with reference to the adjust gas (A). The lifting limit gas is particularly of interest with regard to biomethane interchangeability. This test used gases with the following properties [BTU/scf]:

Adjust gas: Wobbe = 1296, H = 1064

Lifting limit gas: Wobbe = 1179, H = 961

The appliances that were tested included 14 tank water heaters, 15 furnaces, four range burners, four oven burners, a clothes dryer, five boilers, a room heater, a deep fat fryer, and an infrared broiler. Over this range of domestic and commercial appliances, the study found “almost all equipment can perform satisfactorily when properly rated and adjusted on the mid-range adjust gas and exposed to any limit gas.”

More specifically, the author concluded “very little, if any, lifting of burner flames occurred with the appliances as received, when operated with the A, L, Y, or H gases. For the purposes of study, lifting was induced by rating appliances with smaller gas orifices and increasing gas manifold pressures much higher than used in practice to increase primary air injection.” Conclusion of the study was that “the Bulletin 36 index appears to reasonably characterize the lifting tendencies with gas substitutions.”

PG&E (Estrada Jr., 1996)

The objective of the study carried out by PG&E was to “determine whether the limits prescribed by the AGA apply to a typical customer in its service territory” by way of laboratory testing of two water heaters, four ranges, two wall furnaces, and two forced air furnaces. All appliances tested in the study were tuned to receive an adjust gas with a

heating value of 995 BTU/scf, which was the midpoint of the reported range of heating values at the time. The devices were then operated using gas of varying compositions in order to identify the acceptable limits for lifting and yellow tipping. The study concluded that the acceptable limit of gas heating value, based on observed combustion behavior, was 950-1040 BTU/scf. However, this study provides no data regarding the Wobbe Number of the gases used making broad interchangeability conclusions difficult to draw.

SoCalGas (Miller et al., 2005)

In 2005, the Southern California Gas Company (SoCalGas) studied residential and small commercial appliances with the following stated objectives: evaluate safety and performance including carbon monoxide emission and flame stability, compare measured results against interchangeability indices, and collect NO_x emission data. Thirteen appliances were selected based on criteria targeting in-use and emerging devices and technologies with emphasis on those sensitive to gas quality variations. These appliances included the following: a used water heater, floor furnace, and wall furnace, new condensed forced air furnace, FVIR water heater, instant water heater, pool heater, commercial condensing boiler, commercial hot water boiler, low NO_x commercial/industrial steam boiler, ultra-low NO_x steam boiler, a deep fat fryer, and a timed char broiler.

The baseline gas used was SoCalGas line gas at a heating value of 1020 BTU/scf and a Wobbe Number of 1330. Each appliance was tuned to receive this baseline gas and then tested on a variety of test gases. The test gas of interest in this study had a HV of 970 BTU/scf and a Wobbe of 1271 BTU/scf.

The study found no performance issues associated with rapid switching of gases and all equipment was able to operate safely. These appliances all performed satisfactorily when switched rapidly from average line gas with a HV of 1020 BTU/scf to a lower BTU gas with a HV of 970 BTU/scf.

The SoCalGas study did find issues with appliances that rely on timed processes, such as the chain-driven char-broiler tested. If the speed of the chain is set using an adjust gas and then the appliance receives gas with a lower Wobbe, the rate of heat delivery will decrease and the food being prepared may be undercooked.

SoCalGas (CPUC, 2011)

In 2011, Charles Benson provided direct testimony on behalf of SoCalGas before the California Public Utilities Commission. In this testimony, he interpreted the results of interchangeability tests conducted by SoCalGas on a commercial range, a commercial char-broiler, a commercial radiant burner, and an industrial furnace. The objective of the testing was to display that gas which met the California producer Wobbe range of 1199–1465 BTU/scf but failed to meet the narrower Rule 30 restrictions of 1279–1385 BTU/scf can result in user safety or operational issues.

The relevant trials for biomethane interchangeability were conducted with commercial appliances tuned to pipeline gas and then operated on various blends with N₂ and CO₂ to observe the combustion dynamics and measure the emissions.

A commercial range-top burner was tuned to pipeline gas with an HV of 1013 BTU/scf and a Wobbe of 1332 BTU/scf. When the gas supply was changed to be a blend of 92.5% pipeline gas, 7.5% N₂, with a HV of 935 BTU/scf and a Wobbe of 1203 BTU/scf, it is noted that two of the ports had continuous flame lifting and one port had intermittent flame lifting. When the gas supply was changed to be a blend of 92.9% pipeline gas, 7.1% CO₂, with a HV of 950 BTU/scf and a Wobbe of 1195 BTU/scf, it is also noted that the same two of the ports had continuous flame lifting and one port had intermittent flame lifting.

A commercial radiant burner was tuned to pipeline gas with an HV of 1015 BTU/scf and a Wobbe of 1335 BTU/scf. When the gas supply was changed to be a blend of 94.8% CH₄, 5.2% N₂, with a HV of 960 BTU/scf and a Wobbe of 1266 BTU/scf, the bottom part of the burner started showing flame lifting. This level of flame lifting persisted as the supply was altered to gas consisting of an identical HV, but a Wobbe of 1252 and 1237 BTU/scf. Finally, the gas supply was altered to contain 10.2% N₂ and the balance CH₄. Here the author notes the burner shows considerable flame lifting and CO emissions increased noticeably.

One other point of note on the radiant burner testing is the effect of N₂ versus CO₂ on flame lifting. The testimony notes that when the burner was tested with a mix of pipeline gas and 7.5% N₂, with a Wobbe of 1203 BTU/scf, considerable flame lifting was observed. However, when tested with a mix of pipeline gas and 6.8% CO₂ such that the Wobbe would remain 1202 BTU/scf, more flame lifting was noted with the CO₂ mix than the N₂ blend.

The last commercial appliance tested was a char-broiler, which cooked hamburgers for a total of 12.5 minutes. When the test was conducted using a blend of 6.7% CO₂ and the balance pipeline gas (HV of 963 BTU/scf, Wobbe of 1210 BTU/scf) the hamburger patties were visibly undercooked. Timed processes are especially sensitive to gas quality changes as for a lower HV gas, less heat will be delivered in a given time at a constant volumetric flow rate.

Industrial:

The literature is much thinner regarding interchangeability in industrial appliances. However, in 2011 a comprehensive study was conducted by GTI and LBNL to investigate the potential interchangeability concerns with LNG use in industrial burners, home appliances, and commercial foodservice equipment. This study breaks down industrial sector natural gas use by industry seen in the table and figure below.

Table 20. 2011 Industrial gas by sector in California

Industry	Sites in CA	Relative Gas Use (% of industrial)
Petroleum	218	34.8
Oil and Gas Extraction	232	13.1
Food and Beverage	4,544	10.2
Cement, Mineral, and Glass	1,524	7.3
Sugar and Frozen Food	114	6.8
Textile, Paper, Apparel, Publishing	11,506	4.7
Chemical	1,615	4.1
Primary Metal	510	3.9
Fabricated Metal	7,931	3.4
Pulp	1	2.7
Semiconductor	1,500	1.9
Construction	69,023	0.6

All of the experiments were conducted with Wobbe Numbers that vary above the adjust gas and have little direct relevance to interchangeability with biomethane. All experimental tests were conducted with test gases ranging from 1310 to 1425 Wobbe.

This investigation was able to conclude that over the range of tested Wobbe Numbers, all seven industrial combustion appliances were able to function with no operational or safety concerns. No industrial burners were found to have ignition issues, and it is noted that the project team believes this conclusion can be extended to industrial burners not tested in the program.

Appendix B

Empirical studies of siloxane combustion

DNV KEMA Energy & Sustainability (Gersen, 2013)

DNV KEMA Energy & Sustainability performed an early experimental program to estimate the impacts of siloxanes on combustion equipment.

The first experiment sought to determine whether all of the silicon atoms present in siloxane molecules will be converted to silica after combustion. Equilibrium calculations predict a 100% yield of SiO_2 from Si-containing siloxanes. In order to test this experimentally, a filter was attached to the top of the chimney above a ceramic tile burner. The burner was then run using a stoichiometric mix of methane-air with a siloxane (L2) concentration of 66 g Si/m^3 . The burner operated for four hours. By weighing all of the components before and after the test, the team determined that — within experimental uncertainties — all silicon was converted to SiO_2 upon combustion.

A following experiment examined the impact of siloxane-containing fuels on the operation and safety of two domestic appliances. The first appliance was a 22kW modulating, condensing lean-premixed residential boiler operated on gas with siloxane concentrations ranging from 1056 mg Si/m^3 to 33.2 mg Si/m^3 . This boiler was selected due in part to its narrow-channeled heat exchanger. It was hypothesized that this would be a vulnerable appliance to clogging due to siloxane deposition and build-up.

Four trials of this appliance were conducted at varying siloxane concentrations. During each trial, the boiler was operated until the total amount of silica theoretically produced was equal to 50g (assuming a 100% conversion of the silicon in siloxanes to silica molecules). At the start of each trial, the boiler was set to a fixed thermal load of 18 kW. However, over the course of each trial a change in thermal output was noted ranging from -33.3% to -20.6%. The control system of the boiler adjusts the fuel flow linearly in response to airflow and the decrease in thermal output was attributed to the increase in flow resistance as the heat exchanger clogs with silica deposition.

The other appliance tested was a residential 29 kW hot water heater with narrow heat exchanger tubes, and no control system to modify the fuel flow with air flow. Clogging of the tubes will result in decreased air flow and an increase in incomplete combustion yielding CO emissions. Three trials were conducted during which the hot water heater was operated with siloxane-containing fuels of concentrations varying from 521 mg Si/m^3 to 121 mg Si/m^3 until the combustion products reached 1000 ppm CO. Again, the time to 1000 ppm CO

was seen to increase nonlinearly with a decrease in the siloxane concentration. This, again, can be attributed to the dependence of the deposition density on the siloxane concentration in the fuel.

University of Southern California/SoCalGas (Nair et al., 2012, 2013)

Scientists at University of Southern California (USC) worked in conjunction with the SoCalGas Engineering Analysis Center in order to understand the potential impact of siloxanes on end-use equipment (Nair et al., 2012, 2013). This work provides the scientific basis for the current siloxane specification approved by the California Public Utilities Commission for inclusion in Rule 21 and Rule 30.

The first experiment studied internal combustion engines (ICE) burning siloxane-containing gas. Two Honda EU2000i gasoline electric generators were modified to run on natural gas instead of gasoline. These were then operated in parallel for 500 hours, each with a NO_x-reduction catalyst monolith bed attached downstream. The control engine was operated on natural gas containing no siloxanes. For the first 10 hours of study, the test engine was operated on gas containing a varying concentration of siloxanes. However, after this initial period, the test engine was operated with gas containing 43 mg Si/m³. After 200 hours of operation, the spark plugs of the test engine were removed and analyzed for silica deposits. After 403 hours the catalyst beds were removed from both engines and replaced with fresh catalyst beds. After 467.5 hours of operation an oxygen sensor was installed on each engine and its performance was monitored via the voltage signal received from the sensor.

There was no indication of decreased engine performance. After 400 hours of operation, the catalyst bed on the test engine was deactivated by 94.4%. Additionally, there was silica build up in the machine and silica was present in the engine oil, both indicating the potential for increased maintenance costs over longer operational times. Finally, the oxygen sensors installed at approximately 460 hours were removed and tested at the conclusion of operation. The siloxane engine sensor failed a performance test, indicating that if the sensor were controlling engine operation, it would trigger a check engine light after only 40 hours at the tested concentration of siloxanes.

A subsequent experiment tested a residential pulse-combustion furnace. The Lennox 80000 BTU/h PULSE Series direct vent central furnace was chosen in part because of its use of a flame sensor. As shown by previous research, devices which utilize some sort of ionization probe or flame sensor can be particularly susceptible to damage by siloxanes as the deposition can insulate the sensor and render it nonfunctional. The furnace was operated on siloxane-containing gases for a total period of 218.5 hours. First, the furnace was operated with pure natural gas in order to establish a baseline performance for the current running through the flame sensor. Trials were then conducted with siloxane-containing gas until failure of the flame sensor and shut-off of the furnace. Trial concentrations were 86 mg Si/m³ (20 ppm_v, equimolar mixture of L2 and D4), 43 mg Si/m³ (10 ppm_v), and 8.6 mg Si/m³ (2 ppm_v). This study confirmed that flame sensor current decreases over time until eventual

failure. However, no clear trends were found between the concentration of siloxanes at this scale and the time to failure. At 8.6 mg Si/m³, failure occurred at 70 hours, while at 43 and 86 mg Si/m³ failure occurred at 30 and ~40 hours respectively. Furthermore, each sensor failed at a different current and there was no discernable correlation between cumulative moles of siloxane combusted and sensor current.

GTI Assessment of Acceptable Siloxane Concentration (Bora et al., 2013)

In 2013, GTI conducted an assessment of maximum permissible siloxane concentrations using a residential water heater and oven. A Kenmore Model 33637 30-gallon water heater and a Kenmore Model 7040 30-inch oven were selected for testing. Both appliances were fueled by natural gas mixed with D4 and D5 siloxanes at concentrations ranging from 8 to 14 mg Si/m³ for a period of 59 weeks.

The water heater was operational throughout the entire test period with 7428 operating hours simulating approximately 57 months of normal operations. Periodic flue gas samples displayed no significant changes to CO₂ or CO emissions, and while there was significant buildup on the internal heat exchange surfaces of the water heater, there were no operational difficulties.

The unvented oven displayed no effects due to siloxanes until, after 6,890 hours of operation (75 months of simulated operation), the oven's ignitor coil began to fail sporadically due to accumulation of silica deposits. Complete failure occurred at 7,440 hours (81 months of standard operation). Periodic flue gas samples displayed no significant changes to CO₂ or CO emissions.

National Grid UK ("Network Innovation Allowance Project Status Report," 2017)

Most recently, a siloxane impact study was undertaken by National Grid Gas Distribution in conjunction with a team of researchers at DNV GL ("Network Innovation Allowance Project Status Report," 2017). The study began in October 2014 and was completed May 2017. The study originally sought to test appliances on siloxane concentrations down to 0.05 mg Si/m³ in order to provide an unambiguous technical basis for grid injection specifications that will ensure reliability and safety for all downstream consumers.

According to the latest progress report, filed in March 2017, eight appliances were tested based on an inventory of domestic appliances installed in the UK as well as an examination of potential sensitivities to siloxanes. The eight selected appliances were run on gaseous fuel with 11 mg Si/m³ for approximately two months at full capacity. For the four fully premixed domestic boilers and the two partially premixed boilers, no significant increases in CO emissions were shown. The hot water heater displayed a demonstrable increase in CO emissions after 500 hours of operation and estimations show that the appliance would reach the "safety action level" after 1350 hours of operation.

The four fully-premixed boilers displayed silica layer build after 1080 hours of operation, causing a decrease in thermal input of 25%, 17%, 13%, and 9%, respectively. No reduction in thermal load was observed the other devices. Furthermore, three of the four fully-premixed boilers showed reduction in current through the ionization safety device. As a result, these three boilers saw a 'time to failure' of 90 hours, 430 hours, and 986 hours. Based on the above results, the most sensitive of the devices were selected for Phase 3 testing at lower siloxane concentrations. These appliances include three fully premixed boilers and the hot water heater.

Phase 3 testing involved running the appliances on progressively lower silicon content (6.3, 2.8, and 1.5 mg Si/m³) natural gas. The results from this Phase 3 investigation were used to produce a recommendation for maximum silicon content of 0.23 mg Si/m³ based on the time to boiler failure and on linear extrapolation over a 15-year assumed lifetime. As of early 2018, the full report on these experiments has not yet been made public.

Appendix C

Technical summary of siloxane removal technologies

Solid Adsorption Processes

Solid adsorption can be used to bind the volatile siloxane molecules to sites on an adsorptive material. This material can either be disposed of or regenerated, usually by heating. Many types of adsorbents are available for siloxane removal, however, the most common are activated carbon and silica gel. Physical adsorbents have been shown to exhibit a higher affinity for the cyclic siloxanes such as D4 and D5 rather than the linear siloxanes like L2 (Abatzoglou & Boivin, 2009). The removal efficiency of solid adsorption methods can be as high as ~99% depending on how well the system is sized and monitored for breakthrough (Abatzoglou & Boivin, 2009).

Adsorption onto activated carbon is the most common method of siloxane removal (Lampe, 2006). Activated carbon is useful due to its high surface area. Additionally the non-uniform porosity of activated carbon makes it attractive and versatile for trapping a variety of compounds and minor constituents (Soreanu et al., 2011). Typically, activated carbon adsorbent will be placed in a packed column and the biogas will be passed through the media. After saturation, activated carbon is often disposed (Dewil et al., 2006)

Silica gel beads can be used in much the same way as activated carbon. By running the biogas through a packed reactor, siloxanes adsorb onto the gel. The gel can then be regenerated by heating and releasing any siloxanes. One study found that silica gel removed siloxanes three times more effectively than activated carbon (Lampe, 2006).

Liquid Absorption

Scrubbing with water or other solvents has also been suggested, however, in practice the siloxanes are volatile and can be stripped from the solvent if gas flow rates are too high (Ryckebosch et al., 2011). Tetradecane was tested as a solvent in 1996 and found to have a collection efficiency of 97% for D4 siloxanes (Abatzoglou & Boivin, 2009). Absorption methods can take the form of packed columns or spray columns. These methods are generally not expected to be economically feasible for anything other than large flow rates (Abatzoglou & Boivin, 2009).

Refrigeration

Refrigerating the biogas causes condensate to form and some siloxanes are removed with the liquid. The achievable levels are typically not sufficient to eliminate the need for a subsequent clean up step. The energy consumption required for this level of refrigeration is also quite intensive.

The LA County Sanitation District landfill (Lampe, 2006) achieved 50% siloxane removal through refrigeration to 4.5 °C at a pressure of 24 bar. However greater removal efficacy can be seen at lower temperatures. In a bench-scale study on deep refrigeration, a 95% removal of total siloxane can be achieved by cooling to -30 °C (Lampe, 2006).

Degradation

The siloxane molecules can be degraded through use of a strong acid or base. However, strong bases cannot be used because the CO₂ content of biogas would cause the precipitation of carbonates and acids, raising concerns of corrosion (Ryckebosch et al., 2011). Success has been seen with using sulfuric acid solutions at temperatures of 60 °C, but low temperatures will not provide adequate removal of siloxanes (Ryckebosch et al., 2011). It does not appear that significant work has been conducted on this topic. While there has been some preliminary work on the use of microwave reactors to degrade siloxanes into SiO₂ molecules, which can be filtered out, this is used for adsorption media regeneration rather than siloxane removal (Rawson & Spiegel, 2013).

After review of available siloxane removal technologies and current operational experiences, there is evidence to suggest that near complete removal of siloxanes is possible. The most effective siloxane removal techniques will typically leverage several of the above methods in series. For example, the biogas may first be cooled to remove water vapor and, with it, some siloxanes. Subsequently, at a later step, one or more activated carbon vessels may be used to remove any remaining contaminants. The technical details regarding siloxane removal efficiency are not well quantified in the literature, in part due to the measurement uncertainty at low levels of siloxanes.

Appendix D

Technical summary of HV upgrading methods

There are many methods for upgrading biogas HV. The most common method to increase the HV of biogas is by removing inert constituents. Reviews in the literature cover these technologies (Bauer et al., 2013a; Hagen & Polman, 2001; Ong et al., 2014; Persson, 2003; Ryckebosch et al., 2011; Sun et al., 2015). Currently available biogas upgrading methods are considered in this study, however it should be noted that less mature techniques exist as well (e.g., biological upgrading, in situ enrichment, and supersonic separation).

Membrane Separation

Selective membranes can be used to separate CH_4 from CO_2 . The feed gas is pressurized, and the selective membrane allows greater permeance of one species over another. Membrane separators are reliable and simple, but several stages are often needed to achieve high CH_4 purity and membrane replacements can drive up operational expenses. Membrane processes become more difficult and expensive as the desired purity increases. A one-stage membrane system can upgrade biogas to approximately 92% CH_4 , while two- or three-stage systems (arranged in series) can achieve 96% CH_4 (Ryckebosch et al., 2011). Membrane systems often have high methane content in the waste (permeate) stream, which if vented can negate climate benefits of biomethane. The fraction of CH_4 found in the waste stream can be decreased by recirculation of CO_2 -rich permeate (John Boesel & Rutledge, 2005). However, typical permeate streams can contain between 10–25% methane and must be flared or utilized to recover energy (Ryckebosch et al., 2011).

Pressure Swing Adsorption

Pressure Swing Adsorption (PSA) is another method used to remove CO_2 from raw biogas. PSA utilizes zeolites or activated carbon to adsorb CO_2 and other inert constituents from a gaseous mixture. After pressurization, the CO_2 adsorbs to the matrix and the CH_4 -rich product gas is expelled from the vessel. In a purge cycle, the pressure is then reduced to desorb inert gases, which are then rejected. PSA can be used to separate CH_4 from N_2 , O_2 , and CO_2 as all of these species preferentially adsorb onto the media. PSA can upgrade biogas to CH_4 volume fractions of 95 to 98% (Hagen & Polman, 2001; Ong et al., 2014; Sun et al., 2015). Equipment suppliers claim CH_4 losses of ~2%, but cases of 10–12% CH_4 losses have been documented (Ong et al., 2014; Sun et al., 2015). The vented gas must be oxidized to reduce CH_4 -associated GHG impacts.

Amine Scrubbing

Amine absorption is the dominant technology used in the NG industry to remove CO₂ and other acid species from raw NG. Amine scrubbing can achieve CO₂ removal efficiencies greater than 99.5% (Hagen & Polman, 2001; Ryckebosch et al., 2011) hydrogen sulfide, siloxanes, hydrocarbons, ammonia, oxygen, carbon monoxide and nitrogen. In order to transfer biogas into biomethane, two major steps are performed: (1. Amine solvents are regenerated by heating, and some amines are lost due to side reactions. In the case of biomethane, the resultant CH₄ purity will be impacted by the presence of O₂ and N₂ in the raw biogas, which are not removed by amine scrubbing.

Pressurized Water Scrubbing

Water scrubbing takes advantage of the preferential solubility of CO₂ in water compared to CH₄. Water scrubbing is simple and relatively inexpensive, reliably producing gas with CH₄ content of 93-98% (Ryckebosch et al., 2011). CH₄ purity is affected by N₂ and O₂ in the raw gas stream as they are not removed by water scrubbing. CH₄ losses are generally between 3 and 5% (Sun et al., 2015). Water scrubbing consumes large volumes of water. Resulting wastewater is saturated with CO₂ and can be regenerated by decreasing the pressure to release absorbed gases.

Cryogenic Distillation

Cryogenic processes utilize the fact that CO₂ condenses and freezes at a higher temperature than CH₄. First, raw biogas is dried to prevent ice formation in the following steps. After drying, the biogas is compressed to 8000 kPa (80 bar) via intercooled compression. At this point, the biogas can be further cooled to approximately -55 °C and finally expanded to 800-1000 kPa (8-10 bar) in order to cool the gas to -110 °C. At this point the CO₂ will condense in solid phase, and the product gas stream can be removed (Ryckebosch et al., 2011). Cryogenic distillation is energy-intensive but can minimize CH₄ losses. If the desired product is liquefied biomethane, cryogenic techniques are valuable due to production of pre-cooled biomethane.

Propane Addition/Blending

In addition to removal of inert gases, HV specifications can be met by blending biomethane with higher molecular weight hydrocarbons such as propane (C₃H₈). This increases the HV of the product gas. However, this is expensive and reduces the climate benefits of biomethane. Additional safety concerns are raised with regard to housing propane on site at biomethane upgrading facilities. The additional cost incurred by this method of marginal upgrading will be highly dependent on the scale and flow-rate required to meet the specification..

In the same vein of thinking, it has been proposed that biomethane producers can ensure they meet the specifications by mixing their product gas with NG flowing in the nearest

pipeline. Such active blending could be applied in places where the flow of NG is sufficient to allow a well-mixed combination of biomethane and NG to meet the minimum HV specification (see further discussion of dilution in Chapter 6).

Upgrading Summary

Literature suggests that the current specification of 990 BTU/scf is achievable by removal of inert gases but can be challenging due to consistent 98 vol.% CH₄ requirements in the product gas. A recent CEC report concluded that “the higher heating value standards required in California are stricter than those found in other states and countries, and most conventional and emerging gas upgrading technologies may have difficulty in achieving them.” (Ong et al., 2014, p. iii).

Appendix E

Supporting information for economic analysis

E1. Companies contacted and location

Inside U.S.:

BioCNG	Madison, WI
Clean Energy Fuels	Newport Beach, CA
Cornerstone	Middletown, NY
Eisenmann Corporation	Crystal Lake, IL
Energy Systems Group	Newburgh, IN
Guild	Dublin, OH
Prometheus Energy	Houston, TX
Tetra Tech	Pasadena, CA
Unison Solutions	Dubuque, IA

Outside U.S.:

AirScience	Canada
Greenlane Biogas	Canada
Xebec	Canada
Air Liquide	France
Cryostar	France
Prodeval	France
Carbotech	Germany
EnviTec Biogas	Germany
ETW Energietechnik	Germany
Strabag	Germany
DMT	Netherlands
Sysadvance	Portugal
Biosling	Sweden
Malmberg Water	Sweden
Neo-Zeo	Sweden
Puregas Solutions	Sweden
Acrona-systems	Switzerland
Gasrec	UK

E2. Data request document

“We are researching the impact of California’s RNG pipeline injection standards for the cost of supplying renewable natural gas. To this end, we seek your assistance in filling out the cells in the table below. Please input as much information as you can. We deeply appreciate your contributions to this important research that is expected to have significant impact in the determination of standards for renewable natural gas in California and beyond. We commit to protecting your identity and would be happy to acknowledge your help as you see fit. Should have any follow up questions or concerns related to participation please don’t hesitate to contact me, **Austin Stanion** <astanion@ucla.edu>.

Once again, thank you for your time and assistance. We look forward to your participation.

Brief definition of terminology used in the table below

Capital Costs: Equipment, installation, starting media, and other upfront costs.

Cost of Conditioning / Pretreatment: The cost of the process of removing contaminants such as VOCs, ammonia, H₂S, PCBs. We understand this can vary by scenario. Please use a reasonable estimate based on the source gas (landfill, wastewater treatment, etc.).

Composition: Content of source gas including methane and inert gases.

Equipment Life: Working life of the conditioning/upgrading equipment (in years).

Input Flow Rate: Volume of source gas entering upgrading system per hour.

Media Life: Working life of conditioning/upgrading media (e.g. membranes) before replacement is needed.

Media Replacement Costs: Cost of new conditioning/upgrading media, includes associated labor costs.

Monthly O&M Costs: Monthly operations and maintenance costs of equipment, averaged over equipment life. Does not include costs of replacing media.

Outlet Flow Rate: Volume of source gas produced by upgrading system per hour (m³/h).

Outlet Pressure: Pressure of gas produced by upgrading system (psi).

Please read before filling out:

1. We request information for producing RNG from four different sources - Landfill, Wastewater Treatment, Dairy and Municipal Solid Waste, with different compositions for each source gas as shown in the table below.
2. Cells In Green represent cost associated with cost of conditioning and pre-treatment.
3. Cells in Blue represent cost for delivering RNG with a heating value of 990 BTUs per standard cubic foot.
4. Cells in Purple represent cost for delivering RNG with a heating value of 970 BTUs per standard cubic foot.”

Table 21. Data request table provided to biomethane upgrading equipment suppliers

Source Gas Info	Cost of Conditioning/ Pretreatment: Assume average level of contaminants based on source gas	Costs to upgrade to: 990 BTUs per standard cubic foot	Costs to upgrade to: 970 BTUs per standard cubic foot
<u>Landfill:</u> Composition: 45% CH ₄ , 40% CO ₂ , 14% N ₂ , 1% O ₂ Input Flow Rate: 1,110 m ³ /h	Capital Costs: Equipment Life: Monthly O&M Costs: Media/Consumables Replacement Costs: Media Life:	Capital Costs: Equipment Life: Monthly O&M Costs: Media/Consumables Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:	Capital Costs: Equipment Life: Monthly O&M Costs: Media/Consumables Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:
<u>Wastewater Treatment Plant:</u> Composition: 60% CH ₄ , 38% CO ₂ , ~ 1% N ₂ , ~0.5% O ₂ Input Flow Rate: 300 m ³ /h	Capital Costs: Equipment Life: Monthly O&M Costs: Media/Consumables Replacement Costs: Media Life:	Capital Costs: Equipment Life: Monthly O&M Costs: Media/Consumables Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:	Capital Costs: Equipment Life: Monthly O&M Costs: Media/Consumables Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:
<u>Dairy:</u> Composition: 55% CH ₄ , 44% CO ₂ , <1% N ₂ , <1% O ₂ Input Flow Rate: 150 m ³ /h	Capital Costs: Equipment Life: Monthly O&M Costs: Media Replacement Costs: Media Life:	Capital Costs: Equipment Life: Monthly O&M Costs: Media Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:	Capital Costs: Equipment Life: Monthly O&M Costs: Media Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:

Source Gas Info	Cost of Conditioning/ Pretreatment: Assume average level of contaminants based on source gas	Costs to upgrade to: 990 BTUs per standard cubic foot	Costs to upgrade to: 970 BTUs per standard cubic foot
<u>Municipal Solid Waste:</u> Composition: 60% CH ₄ , 36% CO ₂ , 3% N ₂ , ~ 1% O ₂ Input Flow Rate: 700 m ³ /h	Capital Costs: Equipment Life: Monthly O&M Costs: Media Replacement Costs: Media Life:	Capital Costs: Equipment Life: Monthly O&M Costs: Media Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:	Capital Costs: Equipment Life: Monthly O&M Costs: Media Replacement Costs: Media Life: Outlet Flow Rate: Outlet Pressure:

E3. Manufacturer Concerns

In addition to providing estimates of the costs of upgrading biomethane, some manufacturers also expressed insights and concerns about the economic impact of regulation on producers of biomethane. These qualitative observations were gathered both from phone conversations and email exchanges with RNG equipment manufacturers. Three common concerns are noted below.

Manufacturer Concern #1: While equipment manufacturers and producers of biomethane were generally in favor of a lower BTU standard across the state, one biomethane professional advocated in favor of a case-by-case BTU standard rather than a statewide universal standard. This manufacturer argued that a case-by-case standard could take into account nature and scale of the biomethane operation, as well as the type of natural gas pipeline which the biomethane would be injected into. A statewide standard, on the other hand, might set an arbitrary standard across diverse biomethane operating conditions.

Manufacturer Concern #2: Similarly, one biomethane equipment manufacturer noted that HV standards should be relaxed when injecting biomethane into large natural gas pipelines because the ratio of conventional natural gas in the pipeline to injected biomethane would be high compared to biomethane injected into a small pipeline. A higher conventional natural gas to injected biomethane ratio would effectively dilute the injected biomethane, so a lower heating value injection standard would have little to no impact on the quality of natural gas for pipeline consumers. This equipment manufacturer mentioned that some European countries have relative injection standards based on the size of the destination natural gas pipeline.

Manufacturer Concern #3: Finally, almost every manufacturer and biomethane professional agreed that the current California pipeline injection standard of 990 BTUs per standard cubic foot is unnecessarily strict.

Appendix F

Supporting data tables for gas grid simulation

Table 22. HV delivered by zip code for the San Diego regional case study. 1050 BTU/scf was used as baseline for NG and 972 BTU/scf was used for biomethane.

Zip Code	Average HV Delivered by Month (BTU/scf)				Annual Average (BTU/scf) April
	January	April	July	October	
92082	1050	1050	1050	1050	1050
92173	1049	1039	1048	1048	1046
92075	1049	1049	1049	1049	1049
92105	1049	1045	1048	1049	1048
92104	1049	1045	1048	1049	1048
92118	1049	1039	1048	1048	1046
92011	1049	1049	1049	1049	1049
91914	1043	972	1042	1042	1032
92025	1050	1050	1050	1050	1050
92028	1050	1050	1050	1050	1050
92115	1049	1045	1048	1049	1048
92130	1050	1050	1050	1050	1049
91942	1049	1031	1048	1049	1045
92122	1050	1017	1050	1050	1047
92126	1050	1050	1050	1050	1050
92091	1050	1050	1050	1050	1049
92009	1050	1050	1050	1050	1049
92154	1043	972	1042	1042	1032
92007	1049	1049	1049	1049	1049
92026	1050	1050	1050	1050	1050
92124	1047	1040	1046	1046	1044
92109	1049	1049	1049	1049	1049
92117	1050	1050	1050	1050	1049
92119	1045	1031	1043	1044	1041
92056	1050	1050	1050	1050	1050
92127	1050	1050	1050	1050	1050
92116	1049	1045	1048	1049	1048
92084	1050	1050	1050	1050	1050
92120	1049	1045	1048	1049	1048
92027	1050	1050	1050	1050	1050
92008	1050	1050	1050	1050	1049

Appendix F

Zip Code	Average HV Delivered by Month (BTU/scf)				Annual Average (BTU/scf) April
	January	April	July	October	
91941	1046	1031	1045	1045	1042
91910	1049	1039	1048	1048	1046
92129	1050	1050	1050	1050	1050
92010	1050	1050	1050	1050	1050
92014	1049	1049	1049	1049	1049
92024	1050	1050	1050	1050	1049
91977	1046	1031	1045	1045	1042
92071	1045	1031	1043	1044	1041
92057	1050	1050	1050	1050	1050
91950	1049	1039	1048	1048	1046
92078	1048	1050	1047	1047	1039
92081	1050	1050	1050	1050	1050
91945	1049	1034	1048	1049	1046
92020	1045	1031	1043	1044	1041
91911	1049	1039	1048	1048	1046
91913	1043	972	1042	1042	1032
91915	1043	972	1042	1042	1032
91978	1046	1031	1045	1045	1042
92003	1050	1050	1050	1050	1050
92019	1045	1031	1043	1044	1041
92040	1045	1031	1043	1044	1041
92123	1047	1040	1046	1046	1044
92037	1049	1049	1049	1049	1049
92029	1050	1048	1050	1050	1050
92121	1050	1050	1050	1050	1049
92103	1049	1045	1048	1049	1048
92101	1049	1049	1049	1049	1049
92102	1049	1039	1048	1048	1046
92083	1050	1050	1050	1050	1050
92069	1050	1041	1050	1050	1049
92106	1049	1049	1049	1049	1049
92111	1050	1050	1050	1050	1049
92113	1049	1039	1048	1048	1046
92110	1049	1049	1049	1049	1049
92114	1049	1034	1048	1049	1046
92108	1049	1045	1048	1049	1048
92139	1049	1034	1048	1049	1046
92067	1050	1050	1050	1050	1049
92021	1045	1031	1043	1044	1041
92131	1050	1050	1050	1050	1050
91902	1046	1020	1045	1045	1041

Table 23. HV delivered by zip code for the South Bay Area regional case study. 1050 BTU/scf was used as baseline for NG and 972 BTU/scf was used for biomethane.

Zip Code	Average HV Delivered by Month (BTU/scf)				Annual Average (BTU/scf)
	January	April	July	Oct	
94116	1044	1040	1041	1040	1041
95050	1045	1041	1043	1041	1043
94612	1049	1049	1049	1049	1049
94019	1002	991	995	996	997
94108	1039	1031	1035	1033	1034
94606	1049	1049	1049	1049	1049
95139	1049	1049	1049	1049	1049
94588	1049	1049	1049	1049	1049
94121	1044	1039	1040	1040	1041
94014	1046	1042	1043	1043	1043
94541	1049	1049	1049	1049	1049
95131	1050	1049	1050	1050	1050
94086	1042	1036	1035	1036	1037
94542	1049	1049	1049	1049	1049
94024	1046	1043	1043	1043	1044
94404	1045	1041	1041	1041	1042
95122	1050	1049	1050	1050	1050
94605	1049	1049	1049	1049	1049
94601	1049	1049	1049	1049	1049
94607	1049	1049	1049	1049	1049
94061	1046	1043	1043	1043	1044
94010	1046	1042	1043	1043	1043
94134	1044	1039	1040	1040	1041
94582	1049	1049	1049	1049	1049
94618	1049	1049	1049	1049	1049
95032	1050	1049	1050	1050	1050
94806	1049	1049	1049	1049	1049
95119	1049	1049	1049	1049	1049
94705	1049	1049	1049	1049	1049
94586	1050	1050	1050	1050	1050
95118	1050	1049	1050	1050	1050

Table 24. HV delivered by zip code for the Hanford 50% build-out regional case study. 1050 BTU/scf was used as baseline for NG and 972 BTU/scf was used for biomethane.

Zip Code	Average HV Delivered by Month (BTU/scf)		Annual Average (BTU/scf)
	June	Dec	
93235	972	972	972
93202	972	1049	1002
93219	972	972	972
93631	983	1028	993
93230	972	1049	990
93656	972	1036	987
93662	984	1033	996
93212	972	972	972
93272	972	972	972
93256	972	972	972

Table 25. HV delivered by zip code for the Hanford 10% build-out regional case study. 1050 BTU/scf was used as baseline for NG and 972 BTU/scf was used for biomethane.

Zip Code	Average HV Delivered by Month (BTU/scf)		Annual Average (BTU/scf)
	June	Dec	
93235	980	1025	997
93202	1050	1050	1050
93219	972	973	976
93631	1050	1050	1050
93230	1050	1050	1049
93656	972	1050	997
93662	1050	1050	1050
93212	972	972	974
93272	972	973	978
93256	972	973	976

Appendix G

Study Charge

Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Siloxane Specifications

Background

Pursuant to AB 1900 (Gatto, Chapter 602, Statutes of 2012), Public Utilities Code §784 requires the California Public Utilities Commission (CPUC) to adopt common carrier pipeline access rules to “ensure that each gas corporation provides nondiscriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the delivery of gas.” The purpose of the law was to increase California’s use of biomethane, thereby decreasing California’s greenhouse gas emissions.

The CPUC made a series of decisions on how to implement AB 1900’s directive to allow delivery of biomethane to the pipeline. Two of the decisions were as follows:

1. To keep the minimum heating value for gas entering the pipelines of San Diego Gas and Electric (SDG&E) and Southern California Gas Company (SoCalGas) at 990 British thermal units per standard cubic foot (BTU/scf).
2. To permit biomethane generators to blend biomethane with gases possessing a higher heating value before gas enters the pipeline, but to prohibit downstream blending.

Biomethane generated by landfills, sewage treatment plants, and dairies typically has a heating value below 990 BTU/scf. To meet the standard of 990 BTU/scf, biomethane would need to undergo an upgrading process, such as blending with a gas source of a higher heating value. Upstream upgrading costs would be borne by the biomethane generator prior to injection into the pipeline system.

The CPUC decision noted a number of items where there was insufficient evidence presented to justify altering their heating value standard; e.g. they note a lack of scientific evidence that lowering the heating value will not cause end use equipment problems, and that the policies of other states are not in themselves evidence that such a change would not cause problems.

The CPUC requested CCST to undertake a study looking into these issues in accordance with SB 840 (Budget Bill, 2016). The purpose of the study is to provide the state with an up-to-date, independent assessment of the minimum heating value and the maximum siloxanes content of biomethane before it can be injected into the pipeline.

The study scope of work is organized into five key subject areas:

Key Subject Area 1: Heating Value Specification for Pipeline Injection of Biomethane

Key Subject Area 2: Siloxane Specifications for Pipeline Injection of Biomethane

Key Subject Area 3: Options for Purification and Upgrading Biomethane's Heating Value

Key Subject Area 4: Investigation of Dilution of Biomethane After Injection

Key Subject Area 5: Case Studies on Region-Specific and Utility-Specific Considerations

Senate Bill 840 (Budget Bill, 2016)

SEC. 11.

Section 784.1 is added to the Public Utilities Code, to read:

784.1.

(a) The Legislature requests that the California Council on Science and Technology undertake and complete a study analyzing the regional and gas corporation specific issues relating to minimum heating value and maximum siloxane specifications for biomethane before it can be injected into common carrier gas pipelines, including those specifications adopted in Sections 4.4.3.3 and 4.4.4 of commission Decision 14-01-034 (January 16, 2014), Decision Regarding the Biomethane Implementation Tasks in Assembly Bill 1900. The study shall consider and evaluate other states' standards, the source of biomethane, the dilution of biomethane after it is injected into the pipeline, the equipment and technology upgrades required to meet the minimum heating value specifications, including the impacts of those specifications on the cost, volume of biomethane sold, equipment operation, and safety. The study shall also consider whether different sources of biogas should have different standards or if all sources should adhere to one standard for the minimum heating value and maximum permissible level of siloxanes. The study shall develop the best science reasonably available and not merely be a literature review. In order to meet the state's goals for reducing emissions of greenhouse gases and short-lived climate pollutants and the state's goals for promoting the use of renewable energy resources in place of burning fossil fuels, the California Council on Science and Technology, if it agrees to undertake and complete the study, shall complete the study within nine months of entering into a contract to undertake and complete the study.

(b) (1) If the California Council on Science and Technology agrees to undertake and complete the study pursuant to subdivision (a), the commission shall require each gas corporation operating common carrier pipelines in California to proportionately contribute to the expenses to undertake the study pursuant to Sections 740 and 740.1. The commission may modify the monetary incentives made available pursuant to commission Decision 15-06-029 (June 11, 2015), Decision Regarding the Costs of Compliance with Decision 14-01-034 and Adoption of Biomethane Promotion Policies and Program, to allocate some of the moneys that would be made available for incentives to instead be made available to pay for the costs of the study so as to not further burden ratepayers with additional expense.

(2) The commission's authority pursuant to paragraph (1) shall apply notwithstanding whether the gas corporation has proposed the program pursuant to Section 740.1.

(c) If the California Council on Science and Technology agrees to undertake and complete the study pursuant to subdivision (a), within six months of its completion, the commission shall reevaluate its requirements and standards adopted pursuant to Section 25421 of the Health and Safety Code relative to the requirements and standards for biomethane to be injected into common carrier pipelines and, if appropriate, change those requirements and standards or adopt new requirements and standards, giving due deference to the conclusions and recommendations made in the study by the California Council on Science and Technology.

Appendix H

Statement of Work

Study Process

The standard California Council on Science and Technology (CCST) process is tailored to the scope and timeline of this project. Our approach, modeled after the National Academies of Sciences' National Research Council process, is designed to ensure independent, objective, and nonpartisan advice with high standards of scientific and technical quality through the use of recognized experts and peer review. Checks and balances are applied at every step in the Study process to protect the integrity of the reports and to maintain public confidence in them.

Reports are researched and written by principal researchers under the guidance of and with feedback from a steering committee with an appropriate range of expertise, a balance of perspectives, and no conflicts of interest (unless a conflict is deemed unavoidable and is promptly and publicly disclosed). After these two groups come to agreement on a draft report, it is submitted to another set of experts that provide anonymous peer review. The review comments are addressed by the researchers under the oversight of the steering committee. The revised report draft and comment responses are subsequently assessed for adequacy by a fourth set of expert called the "report monitor." The researchers, again under the guidance of the steering committee, make further adjustments to address any response inadequacies identified by the report monitors.

CCST strives to produce reports through a transparent process to ensure that the final product is responsive to the questions of the sponsor, while maintaining full scientific independence. Transparency is achieved by engaging the sponsor in dialogue about the nature of the information they need and informing the sponsoring agency of our progress, typically with monthly meetings and written updates.

More details on CCST's Study process are available at <http://ccst.us/ccstinfo/process.php>.

Preliminary Questions¹

CCST will consider the following questions within each chapter:

Chapter 1: Heating Value (HV) Specification for Pipeline Injection of Biomethane

Questions:

- a. What is the typical current and historical range of heating values in public gas pipelines in California?
- b. What are the Heating Value specifications for biomethane injection in other states? How did they arrive at those standards?
- c. What is the typical range of heating values in raw biogas from its major sources in CA (including agricultural waste digesters, forestry residues, landfills, food waste, dairies, and sewage treatment plants)?
- d. What processes are available, including blending and removal of inert constituents, for upgrading the heating value of biomethane, and what is the range of heating values typically attained?
- e. What are the technical considerations in blending to increase the heating value of biomethane? What is the process for obtaining other gases for blending, such as flowing gas supplies in a utility pipeline system? What proportion of other gases possessing a higher heating value (including liquid petroleum fuels or diverted flowing gas supplies from the utility pipeline system) are required to raise the heating value of biomethane to a given level?
- f. What are the cost implications of upstream upgrading (prior to injection into the pipeline system) versus downstream upgrading (such as by dilution following injection into the pipeline system)? How do these cost implications affect the volume of biomethane potentially viable to produce?
- g. Are there safety trade-offs on the production side for upstream upgrading versus downstream dilution?
- h. What are the potential impacts of using lower HV gas in appliances (residential, commercial, and industrial) that are tuned for a higher HV baseline?

1. The degree to which the following questions can be addressed may be constrained by the timeframe and funding available for this Study.

- i. Are there scientific studies documenting the use of lower HV gas in residential, commercial, and industrial appliances tuned for pipeline-quality natural gas?
- j. How does the current utility heating value specification for natural gas avoid operational, efficiency, or safety issues for public utilities, or consumers in the utility's service territory? If revised, what are the issues that could arise?
- k. How does the current utility heating value specification for natural gas ensure gas interchangeability? If revised, what operational, efficiency, human health or pipeline safety and integrity impacts would this have with regard to interchangeability?
- l. How does the heating value specification affect potential total volume of biomethane used in the state?
- m. How does the heating value specification affect the cost to produce biomethane in California?
- n. What is the technical feasibility of other approaches for increasing the heating value of biomethane apart from blending, such as removal of low heating value constituents? How do other options compare in cost and safety to blending?
- o. Is it appropriate to establish separate heating value specs based on the source of biomethane?

Chapter 2: Siloxane Specifications for Pipeline Injection of Biomethane

Questions:

- a. What is the typical range of siloxane concentration and composition in biomethane from its major sources in CA (including agricultural waste digesters, forestry residues, landfills, dairies, and sewage treatment plants)?
- b. What are the current siloxane specifications for biomethane injection in other states and jurisdictions? How did they arrive at these standards?
- c. Review of international experience with siloxane regulation.
- d. What processes are available for purification of biomethane of siloxanes? What range of concentration is achievable and verifiable? Can action be taken to upgrade or purify biomethane feedstock to improve the siloxane concentrations of biomethane for pipeline injection?
- e. What are the impacts of siloxane on end-use equipment and on pipeline infrastructure?

- f. Are there scientific studies documenting the use of gas with higher siloxane concentration in appliances? Residential, commercial, industrial?
- g. What are the current specifications for siloxane concentration limits by manufacturers of the end-use equipment?
- h. What is siloxane's effect on pipeline integrity and what are possible impacts of revised siloxane standards on human health? Include the potential health impacts of the post-combustion products of siloxanes.
- i. How does the current siloxane specification impact the cost to produce biomethane in California?
- j. How does the current siloxane specification impact the volume of biomethane produced in California?
- k. Is it appropriate to establish separate siloxane specs or verification regimes based on the source of biomethane?

Chapter 3: Options for Dilution of Biomethane after Pipeline Injection

Questions:

- a. What is the reasonable expectation of diffusion and mixing of biomethane into a pipeline? What conditions (pressure, proportional flow-rate, residence time) is necessary for acceptable mixing? After what distance does biomethane signature become indistinguishable from background gas?
- b. What are the locations of the possible injection sites? What are the locations of the end-users?
- c. What percentage of gas is going to a user facility that could be treated on site prior to customer use?
- d. Does dilution occur on gas distribution lines as well as gas transmission lines?
- e. Are there areas of gas utility service territories where dilution is not possible or problematic due to low volumetric flow-rates of compliant gas?
- f. Could dilution problems feature seasonal trends?
- g. Would downstream dilution affect the cost to produce biomethane in CA? How could this impact potential volume of biomethane?

- h. Are there safety trade-offs on the utility side for dilution compared to active upstream upgrading?

Chapter 4: Case Studies on Region-Specific and Utility-Specific Considerations

Questions:

- a. Explore possible injection scenarios based on specific regions of CA or specific utility systems
- b. From a regulatory perspective, what are the variations between California gas utility standards of injection and how might this need to change to accommodate biomethane?

Chapter 5: Summary and Future Directions

Questions:

- a. Are there areas that are in need of deeper research (i.e., experimental study) in order to definitively draw conclusions about equipment use with lower HV and/or higher siloxane concentrations?
- b. Are there other options besides lowering the specified heating value and upgrading biomethane to allow biomethane into the public gas pipelines?
- c. Which of above options will minimize costs, maximize benefits, and allow efficient and safe delivery of biomethane to public utilities? How well are these costs and benefits understood?

Sources

This Study will be conducted as a synthesis of existing available data including the results of many currently on-going or recently related studies, protocols and proposed regulations. The quality of the assessment will depend on the quality of the information and time available for the study and the study will include an assessment of data adequacy and limitations posed by time constraints. Every effort is made to use publically available data where possible.

Appendix I

CCST Steering Committee Members

The Steering Committee (SC) oversees the report authors, reaches conclusions based on the findings of the authors, drafts recommendations and writes an executive summary. Lead authors and technical experts for each chapter also serve as ex officio, non-voting SC members.

Full *curricula vitae* for the SC members are available upon request. Please contact the California Council on Science and Technology (916) 492-0996.

Steering Committee Members

- **James L. Sweeney**, Stanford University and Chair of the CCST Council (Chair)
- **Charles Benson**, etaPartners LLC
- **Fokion Egolfopoulos**, University of Southern California
- **Charles Kolstad**, Stanford University
- **Diane Saber**, REEthink
- **Jessica Westbrook**, Sandia National Laboratories

Ex Officio, Non-Voting Committee Members

- **Adam Brandt (Lead Author)**, Stanford University

James L. Sweeney, Ph.D., Steering Committee Chair

*Director, Precourt Energy Efficiency Center, Professor of Management Science & Engineering,
Senior Fellow at Precourt Institute for Energy and at the Stanford Institute For Economic Policy
Research and, by courtesy, at The Hoover Institution*

CCST Council Chair

Dr. Sweeney is the CCST Council Chair, the director and founder of Stanford's Precourt Energy Efficiency Center, and professor of Management Science and Engineering. He is a senior fellow of the U.S. Association for Energy Economics, CCST, Hoover Institution, Precourt Institute for Energy, and Stanford Institute for Economic Policy Research. At Stanford he has served as Director of the Energy Modeling Forum, Chairman of the Institute for Energy Studies, and Director of the Center for Economic Policy Research (now Stanford Institute for Economic Policy Research). He is a member of the external Council Chair advisory council of the National Renewable Energy Laboratory and of the California Energy Commission's Petroleum Market Advisory Committee. He was a founding member of the International Association for Energy Economics and has been a member of numerous National Research Council committees. Dr. Sweeney earned his bachelor's degree from MIT in electrical engineering and his Ph.D. from Stanford in engineering-economic systems.

Adam Brandt, Ph.D.*

Assistant Professor of Energy Resources Engineering and Center Fellow, by courtesy, at the Pre-court Institute for Energy

Dr. Brandt holds a Ph.D. and M.S. in energy and resources from the University of California, Berkeley. He is interested in reducing the environmental impacts of energy systems and, more specifically, in understanding, measuring, and reducing greenhouse gas (GHG) emissions from fossil energy sources. His research uses the tools of life cycle assessment (LCA) and process optimization to measure and estimate impacts from technologies at broad scales (LCA) and to help reduce these impacts (optimization). More specifically, his research focuses on the environmental impacts of oil shale and other substitutes for conventional petroleum; mathematical modeling of petroleum depletion and the transition to oil substitutes; and capture and storage systems. He serves on the Science Advisory Panel, Methane Reconciliation Project, National Renewable Energy Laboratory and was a technical steering committee member for an Independent Review of Well Stimulation by the California Council on Science and Technology. Dr. Brandt earned a B.S. in environmental studies with an emphasis on physics from UC Santa Barbara.

** The individual marked with an asterisk is an Ex Officio, Non-Voting Steering Committee member due to his role as the lead author for the report. Serving as an ex officio, non-voting member ensures regular interaction with the rest of the Steering Committee and improves the quality of the final report.*

Charles Benson

Managing Partner, etaPartners LLC

Charles Benson is the Managing Partner of etaPartners LLC. He has 35 years of experience in the development, design, and optimization of energy systems. His work has focused on applications in the industrial, power generation, commercial, and residential sectors. These include industrial furnaces, boilers, gas turbines, and appliances. Of note is his work on low-NO_x burner technologies and on the utilization of new fuels. He has worked with natural gas producers, pipeline companies, and local distribution companies to address interchangeability issues associated with the distribution of shale gas, coal bed methane, liquefied natural gas, propane-air peak shaving gas, and bio-derived gas. Prior positions that he has held include engineering roles at Pratt & Whitney and Exxon Research & Engineering Co., Vice President at Arthur D. Little Inc., Energy & Transportation Technology Sector Leader at TIAX LLC, and Principal at ENVIRON International Corp. Mr. Benson is an officer of the American Flame Research Committee. He also serves on the Executive Committee and Council of the International Flame Research Foundation.

Fokion Egolfopoulos, Ph.D.

William E. Leonhard Professor in Engineering, Department of Aerospace and Mechanical Engineering, University of Southern California

Professor Egolfopoulos is the founder of the Combustion and Fuels Research Laboratory at the University of Southern California. He has been actively involved in research for more than 25 years on the fundamentals that control a variety of phenomena encountered in high-temperature, high-activation energy reacting flows. Examples of such phenomena include physical and chemical processes in flames, high-speed air-breathing propulsion, turbulent combustion, plasma-assisted combustion, conventional and alternative fuels, and mechanisms of combustion-generated oxides of nitrogen, to name a few. Dr. Egolfopoulos is the Editor in Chief of *Combustion and Flame* since 2009 and a member of the Editorial Board of *Progress in Energy and Combustion Science*. He is a Fellow of the American Society of Mechanical Engineers (ASME) Fellow, an Associate Fellow of the American Institute of Aeronautics and Astronautics (AIAA), and an elected member of to the Board of Directors of the Combustion Institute. He received his Ph.D. in mechanical engineering from the University of California, Davis, his master's degree in mechanical engineering from San Jose State University, and his Diploma degree in mechanical engineering from National Technical University of Athens, Greece.

Charles D. Kolstad, Ph.D.

*Senior Fellow at the Stanford Institute for Economic Policy Research
and at the Precourt Institute for Energy*

Dr. Kolstad is an energy and environmental economist with a research focus on regulation. Much of his applied work is in the area of climate change and energy markets. He has been a Convening Lead Author for the Intergovernmental Panel on Climate Change (co-recipient of the 2007 Nobel Peace Prize), is a founding Co-Editor of the Oxford University Press journal *Review of Environmental Economics & Policy* and has served on many advisory boards. He is currently a Council Member for the California Council on Science and Technology (CCST) and a former president of the Association of Environmental and Resource Economists (AERE). At Stanford, in addition to his affiliation with the Department of Economics, Dr. Kolstad holds senior fellow appointments in the Precourt Institute for Energy (PIE), the Stanford Institute for Economic Policy Research (SIEPR) and the Woods Institute for the Environment. Prior to joining Stanford in 2012, Dr. Kolstad was on the faculty of the University of California, Santa Barbara, where he was a Bren Distinguished Professor of Environmental Economics, Chair of the Department of Economics and co-director of the system-wide University of California Center for Energy and Environmental Economics (UCE3). Dr. Kolstad holds a Ph.D. in engineering-economic systems and economics from Stanford University, a M.A. in mathematics from the University of Rochester, and a B.S. in mathematics from Bates College in Maine.

Diane Saber, Ph.D.

President, REEthink

Diane Saber, Ph.D., is a nationally recognized expert in the area of production and characterization of biomethane, having conducted the largest collaborative research projects in this area to date. In 2008, the industry-funded (22 natural gas companies world-wide) report, Pipeline Quality Biomethane: North American Guidance Document for Dairy Waste Conversion was produced; this served as a template for the further study funded by DOT/PHMSA, Pipeline Quality Biogas: Guidance Document for Dairy Waste, Wastewater Treatment Sludge and Landfill Conversion (2009). Dr. Saber also served as contributor and sole non-utility author of the Canadian Gas Association's Report, Biomethane Guidelines for the Introduction of Biomethane into Existing Natural Gas Distribution & Transmission Systems (2011). These reports serve as seminal works in the development of pipeline quality biomethane in North America, with particular insights into trace constituents in biogas/biomethane and natural gas, including biologicals. She was also responsible for the creation and management of a wide variety of projects associated with biomethane, including analytical techniques, database construction and company-specific specifications. She was previously a Director at the Gas Technology Institute in Des Plaines, IL, responsible for a multi-million dollar portfolio of projects and research specific to the Natural Gas industry in the areas of renewable natural gas, environmental science and forensic chemistry. Dr. Saber holds a Ph.D. in microbiology from the University of Minnesota.

Jessica Westbrook, Ph.D.

Principal Member of Technical Staff, Sandia National Laboratories

Dr. Westbrook is a Principal Member of Technical Staff at Sandia National Laboratories. She is a Council Member for the California Council on Science and Technology (CCST) and was a CCST Science and Technology Policy Fellow, placed as a consultant on the State Assembly Natural Resources Committee. While working for the Committee, she published numerous Senate and Assembly bill analyses relating to advanced energy storage, California Air Resources Board member qualifications, electricity, air pollution, and the economic impacts of climate change, to name a few. Dr. Westbrook earned a Ph.D. from the Department of Horticulture at Cornell University and received her B.S. in plant biology from the University of California, Davis.

Appendix J

Science Team Report Author Biosketches

Report Authors

Professor Adam Brandt, the report's lead author, and Gregory Von Wald at Stanford University primarily researched and wrote the body of the report. In addition, Professor Deepak Rajagopal and Austin Stanion at the University of California, Los Angeles (UCLA) assisted in writing the economics sections of the report.

- Adam Brandt*, Stanford University
- Gregory Von Wald, Stanford University
- Deepak Rajagopal, UCLA
- Austin Stanion, UCLA

**Lead author and Ex Officio, Non-Voting Steering Committee Member*

ADAM BRANDT

Dept. of Energy Resources Engineering

Stanford University

Green Earth Sciences 065

Phone: (650) 724-8251, abrandt@stanford.edu

EDUCATION

- | | |
|------|---|
| 2008 | PHD, ENERGY AND RESOURCES, University of California, Berkeley |
| 2005 | MS, ENERGY AND RESOURCES, University of California, Berkeley |
| 2003 | BS, ENVIRONMENTAL STUDIES (emphasis Physics), Highest Honors, University of California, Santa Barbara |

CURRENT AND PAST POSITIONS

- | | |
|--------------|---|
| 2012-Present | Assistant Professor, Department of Energy Resources Engineering, Stanford University |
| 2009-2012 | Acting Assistant Professor, Department of Energy Resources Engineering, Stanford University |
| 2010-2011 | Technical Consultant, Directorate General Climate Action European Commission, Brussels, Belgium |
| 2007-2009 | Consultant, Life Cycle Associates LLC, Portola Valley, CA |
| 2008 | Consulting Author, UK Energy Research Centre, Imperial College London, United Kingdom |
| 2007-2008 | Teaching Assistant, University of California, Santa Barbara |
| 2006 | Consultant, Natural Resources Defense Council, San Francisco, California |

HONORS AND AWARDS

- | | |
|------|---|
| 2006 | Student Paper Award for paper “Testing Hubbert,” 26th Annual Conference of the United States Association of Energy Economists |
|------|---|

GREGORY VON WALD

*Dept. of Energy Resources Engineering
Stanford University
gvonwald@stanford.edu*

EDUCATION

Exp. 2018	MS, ENERGY RESOURCES ENGINEERING, Stanford University, Stanford, CA
2016	BS, INTEGRATED SCIENCE & TECHNOLOGY, James Madison University, Harrisonburg, VA

CURRENT AND PAST POSITIONS

2016-Present	Graduate Research Assistantship, Environmental Assessment and Optimization Group, Stanford, CA
2016	ISAT Senior Capstone Research, James Madison University, Harrisonburg, VA
2015	Technology Consulting Analyst Intern, Accenture Federal Services (AFS), Arlington, VA
2014	Systems Analysis Intern, Department of Energy, Office of Energy Efficiency and Renewable Energy, Washington D.C.

DEEPAK RAJAGOPAL

*Inst. of Environment and Sustainability, Dept. of Urban Planning
University of California, Los Angeles
Phone: 310-794-4903, rdeepak@ioes.ucla.edu*

EDUCATION

2009	PHD, ENERGY AND RESOURCES, University of California, Berkeley
2009	MS, AGRICULTURAL AND RESOURCE ECONOMICS, University of California, Berkeley
2001	MS, MECHANICAL ENGINEERING, University of Maryland, College Park, MD
1999	B.TECH, MECHANICAL ENGINEERING, Indian Institute of Technology, Madras, India

CURRENT AND PAST POSITIONS

2010-Present	Assistant Professor, Institute of the Environment and Sustainability, University of California, Los Angeles
2013-2015	Visiting Assistant Professor, School of Public and Environmental Affairs, Indiana University, Bloomington, IN
2009-2010	Postdoctoral Researcher, Energy Biosciences Institute, University of California, Berkeley
2001-2004	Engineer in Structural Integrity and Reliability, United Technologies Research Center, East Hartford, CT

HONORS AND AWARDS

2009	Student Paper Award, "Greenhouse gas regulation of transportation fuels: Emission quota versus intensity standards," 32nd Annual Conference of the International Association for Energy Economics
2005	United Nations Industrial Development Organization and University of California Berkeley, Management of Technology Program Fellowship, Haas School of Business

2003	Outstanding Achievement Award for the project on Modeling and Analysis of Cooling, Heating and Power (CHP) Systems for Buildings, United Technologies Research Center
2002	Outstanding Achievement Award for the project Integrated Total Aircraft Power Systems Modeling and Analysis, United Technologies Research Center
2000	Outstanding Teaching Assistant Award for 1999-2000 by the Center for Teaching Excellence, University of Maryland

AUSTIN JUDE STANION

*Luskin School of Public Affairs
University of California, Los Angeles
astanion@ucla.edu*

EDUCATION

- Exp. 2019 MS, URBAN AND REGIONAL PLANNING, Transportation Policy and Planning, Luskin School of Public Affairs, University of California, Los Angeles
- 2012 BA, ANTHROPOLOGY, University of North Carolina, Chapel Hill

PAST AND CURRENT POSITIONS

- 2017-Present Master's student in Urban and Regional Planning at the UCLA Luskin School of Public Affairs

HONORS AND AWARDS

- 2012-2014 Venture For America Fellow
- 2012 Robertson Scholar, full tuition merit scholarship to UNC and Duke, including research in New Orleans, Sierra Leone, and Detroit

Appendix K

Glossary

Absorption – Process by which an atom, compound, or molecule enters a bulk liquid phase

Activated carbon – Bulk carbon media that has been processed to consist of very small pores which increase the surface area available for chemical reactions and adsorption of molecules

Adsorption – Process by which an atom, compound or molecule adheres to a solid surface

Anaerobic digestion – The process by which organic matter is broken down by microbes in an environment without oxygen, typically producing a gaseous mixture of largely carbon dioxide and methane among many other trace constituents.

Billing factors – Factors employed by Southern California Gas Company to correct customer bills for deviations in the energy content of gas delivered each month.

Biogas – Unprocessed product gas of anaerobic digestion consisting of largely carbon dioxide and methane.

Biogas upgrading – Process by which trace contaminants and inert major components are removed from raw biogas to produce biomethane.

Biomethane – Biogas that has been processed, or upgraded, to the point that it can be considered a substitute for natural gas.

Blending – Combining two gas streams to create a gaseous mixture.

Blow-off – Combustion phenomenon occurring when the flame is extinguished or “blown-off” the burner tip.

British thermal unit (BTU) - The amount of heat required to raise the temperature of one pound of water by one degree, Fahrenheit.

BTU districts – Geographical segmentations of a gas utility service territory which receive historically different energy content in the gas delivered.

Compressibility – The deviation in thermodynamic properties observed for a real gas compared to those expected for an ideal gas.

Cryogenic distillation – Using very low temperatures to separate compounds with different freezing points

Discount rate – Interest rate used for the purposes of calculating present value of an investment.

Flame lifting – Combustion phenomenon occurring when there is a decrease in the rate of energy delivered to the point of combustion coupled with an increase in the flow rate of gas through the burner tip. This can cause the flame to “lift” off the burner tip. This lifting may allow for some fuel to escape with only partial oxidation, leading to CO emissions or blow out (extinguishment) of the flame.

Flashback – The reverse flow of a flame or gas into the point of supply

Heating value - Essentially the amount of heat released when a fuel is burned, most commonly presented in units of thermal energy per standard unit of volume

Higher heating value (HHV) – Total energy content of a fuel measured as the gross heat of combustion available by combusting the fuel at standard conditions. Fuels are combusted with all reactants starting at a standard temperature of 25 °C. The combustion products are then cooled back to standard temperature of 25 °C and the removed sensible heat is measured. Also known as gross calorific value (GCV).

Incomplete combustion – Combustion phenomenon occurring when hydrocarbons are only partially oxidized, resulting in carbon monoxide formation. Incomplete combustion can arise when there is insufficient air flow at the point of combustion or when reactants are not adequately mixed.

Inert gas – Non-combustible gaseous compound such as carbon dioxide and nitrogen.

Interchangeability – The ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency, performance or materially increasing air pollutant emissions.

Latent heat of vaporization – The energy needed to break the intermolecular forces which maintain the liquid phase.

Lower heating value (LHV) – The higher heating value less the latent heat of vaporization of water vapor in combustion products. In other words, the LHV is the amount of energy available without condensing moisture in exhaust products. Also known as net calorific value (NCV).

Mole fraction – The percentage of molecules in a gaseous mixture (synonymous with vol.%).

Natural gas – A mixture of various gases (mostly methane, ethane, and propane) produced from subsurface geologic reservoir rocks. The original source material for natural gas is ancient, buried organic matter.

Raw biogas – The unprocessed, gaseous product of anaerobic digestion of organic matter by microbes, containing a mixture of CH₄, CO₂, and many other constituents. Can be upgraded to biomethane.

Receipt point – The location at which the local distribution company accepts gas into the intrastate pipeline.

Rule 21 – Tariff of regulations regarding transportation of gas by Pacific Gas and Electric Company (PG&E).

Rule 30 – Tariff of regulations regarding transportation of customer-owned gas by Southern California Gas Company (SoCalGas).

Siloxane – A family of volatile organic silicon-containing compounds often containing oxygen and silicon (O-Si-O) bonds, with methyl (CH₃) groups bound to the silicon atoms. Siloxanes can be cyclic or linear in structure and are often referred to by abbreviations such as L2, D4, etc. with the number indicating the number of silicon atoms and the letter indicating the structure (linear, L or cyclic, D).

Specific gravity – The density of a gaseous mixture at standard conditions relative to the density of air.

Upgrading – The process by which raw biogas is turned into biomethane, including the removal of inert components to increase heating value

Vol.% - The percentage by volume (synonymous with mole fraction).

Wobbe index – A metric for gaseous fuel interchangeability defined as the higher heating value of a gas divided by the square root of the gas specific gravity (also called Wobbe Number).

Appendix L

Review of Information Sources

This study was conducted as a synthesis of existing publically available data including the results of many currently on-going or recently completed relevant studies, protocols and proposed regulations. The quality of the assessment depended on the quality of the information and time available for the study. The study includes an assessment of data adequacy and limitations posed by time constraints.

Our scientists cited a given reference in the report if it met all three of the following criteria:

1. Fit into one of the seven categories of admissible literature (described in a-g below).
 - a. Published, peer-reviewed scientific papers.
 - b. Government data and reports including analysis of available data from CPUC, DOGGR, and other publically available sources.
 - c. Academic studies that are reviewed through a university process, textbooks, and papers from technical conferences.
 - d. Studies generated by non-government organizations that are based on data, and draw traceable conclusions clearly supported by the data.
 - e. Voluntary reporting from industry. This data is cited with the caveat that, as voluntary, there is no quality control on the accuracy or completeness of the data.
 - f. Other relevant publications including reports and theses. We state the qualifications of the information used in the report.
 - g. Additional authoritative sources including the expert opinion of the committee and scientific community.
2. Was relevant to the scope of the report.
3. Added substantive information to the report.

For this report, the authors reviewed many sources of public information, including some that are not easily accessible to all citizens, such as fee-based scientific journals. If a member of the public wishes to view a document referenced in the report, they may visit California Council on Science and Technology at 1130 K Street, Suite 280, Sacramento, CA 95814-

3965. We cannot duplicate or electronically transmit copyright documents. Please make arrangements in advance by contacting CCST at (916) 492-0996.

When appropriate, proprietary data were requested by CCST from the CPUC and from utilities. Not all requests were honored. Despite the data limitations, information gathered from multiple independent sources gives largely consistent results, and the authors think the report findings are generally accurate and representative of biomethane injection into the common carrier pipeline in California. Additional data in the future might change some of the quantitative findings about biomethane injection in the report, but, absent some major external influence, it is unlikely these will fundamentally alter the report findings.

Appendix M

California Council on Science and Technology Study Process

California Council on Science and Technology (CCST) studies are viewed as valuable and credible because of the organization's reputation for providing independent, objective, and nonpartisan advice with high standards of scientific and technical quality. Checks and balances are applied at every step in the study process to protect the integrity of the studies and to maintain public confidence in them.

Study Process Overview—Ensuring Independent, Objective Advice

For nearly 30 years, CCST has been advising California on issues of science and technology by leveraging exceptional talent and expertise.

CCST enlists the state's foremost scientists, engineers, health professionals, and other experts to address the scientific and technical aspects of society's most pressing problems.

CCST studies are funded by state agencies, foundations and other private sponsors. CCST provides independent advice; external sponsors have no control over the conduct of a study once the statement of task and budget are finalized. Authors and the Steering Committee gather information from many sources in public and private meetings but they carry out their deliberations in private in order to avoid political, special interest, and sponsor influence.

Stage 1: Defining the Study

Before the author and Steering Committee selection process begins, CCST staff works with sponsors to determine the specific set of questions to be addressed by the study in a formal "statement of task," as well as the duration and cost of the study. The statement of task defines and bounds the scope of the study, and it serves as the basis for determining the expertise and the balance of perspectives needed for the study authors, Steering Committee members, and peer reviewers.

The statement of task, work plan, and budget must be approved by CCST's Project Director in consultation with CCST leadership. This review sometimes results in changes to the proposed task and work plan. On occasion, it results in turning down studies that CCST believes are inappropriately framed or not within its purview.

Stage 2: Study Authors and Steering Committee (SC) Selection and Approval

Selection of appropriate authors and SC members, individually and collectively, is essential for the success of a study. All authors and SC members serve as individual experts, not as representatives of organizations or interest groups. Each expert is expected to contribute to the project on the basis of his or her own expertise and good judgment. The lead author(s) serves as an ex officio, nonvoting member of the SC to ensure continued communication between the study authors and the SC. CCST sends nominations of experts to the Oversight Committee (made up of two CCST Board Members and an outside expert) for final approval after conducting a thorough balance and conflict of interest (COI) evaluation including an in-person discussion. Any issues raised in that discussion are investigated and addressed. Members of a SC are anonymous until this process is completed.

Careful steps are taken to convene SCs that meet the following criteria:

An appropriate range of expertise for the task. The SC must include experts with the specific expertise and experience needed to address the study's statement of task. A major strength of CCST is the ability to bring together recognized experts from diverse disciplines and backgrounds who might not otherwise collaborate. These diverse groups are encouraged to conceive new ways of thinking about a problem.

A balance of perspectives. Having the right expertise is not sufficient for success. It is also essential to evaluate the overall composition of the SC in terms of different experiences and perspectives. The goal is to ensure that the relevant points of view are, in CCST's judgment, reasonably balanced so that the SC can carry out its charge objectively and credibly.

Screened for conflicts of interest. All provisional SC members are screened in writing and in a confidential group discussion about possible conflicts of interest. For this purpose, a "conflict of interest" means any financial or other interest which conflicts with the service of the individual because it could significantly impair the individual's objectivity or could create an unfair competitive advantage for any person or organization. The term "conflict of interest" means something more than individual bias. There must be an interest, ordinarily financial, that could be directly affected by the work of the SC. Except for those rare situations in which CCST determines that a conflict of interest is unavoidable and promptly and publicly discloses the conflict of interest, no individual can be appointed to serve (or continue to serve) on a SC used in the development of studies if the individual has a conflict of interest that is relevant to the functions to be performed.

Point of View is different from Conflict of Interest. A point of view or bias is not necessarily a conflict of interest. SC members are expected to have points of view, and CCST attempts to balance these points of view in a way deemed appropriate for the task. SC members are asked to respectfully consider the viewpoints of other members,

to reflect their own views rather than be a representative of any organization, and to base their scientific findings and conclusions on the evidence. Each SC member has the right to issue a dissenting opinion to the study if he or she disagrees with the consensus of the other members.

Other considerations. Membership in CCST and previous involvement in CCST studies are taken into account in SC selection. The inclusion of women, minorities, and young professionals are additional considerations.

Specific steps in the SC selection and approval process are as follows:

CCST staff solicit an extensive number of suggestions for potential SC members from a wide range of sources, then recommend a slate of nominees. Nominees are reviewed and approved at several levels within CCST. A provisional slate is then approved by the Oversight Committee. Prior to approval, the provisional SC members complete background information and conflict-of-interest disclosure forms. The SC balance and conflict-of-interest discussion is held at the first SC meeting. Any conflicts of interest or issues of SC balance and expertise are investigated; changes to the SC are proposed and finalized. The Oversight Committee formally approves the SC. SC members continue to be screened for conflict of interest throughout the life of the committee.

CCST uses a similar approach as described above for SC development to identify study authors who have the appropriate expertise and availability to conduct the work necessary to complete the study. In addition to the SC, all authors, peer reviewers, and CCST staff are screened for COI.

Stage 3: Author and Steering Committee Meetings, Information Gathering, Deliberations, and Drafting the Study

Authors and the Steering Committee typically gather information through:

1. meetings;
2. submission of information by outside parties;
3. reviews of the scientific literature; and
4. investigations by the study authors and/or SC members and CCST staff.

In all cases, efforts are made to solicit input from individuals who have been directly involved in, or who have special knowledge of, the problem under consideration.

The authors shall draft the study and the SC shall draft findings and recommendations. The SC deliberates in meetings closed to the public in order to develop draft findings and

recommendations free from outside influences. All analyses and drafts of the study remain confidential.

Stage 4: Report Review

As a final check on the quality and objectivity of the study, all full CCST reports must undergo a rigorous, independent external peer review by experts whose comments are provided anonymously to the authors and SC members. CCST recruits independent experts with a range of views and perspectives to review and comment on the draft report prepared by the authors and the SC.

The review process is structured to ensure that each report addresses its approved study charge, that the findings are supported by the scientific evidence and arguments presented, that the exposition and organization are effective, and that the report is impartial and objective.

The authors and the SC must respond to, but need not agree with, reviewer comments in a detailed “response to review” that is examined by one or more independent “report monitor(s)” responsible for ensuring that the report review criteria have been satisfied. After all SC members and appropriate CCST officials have signed off on the final report, it is transmitted to the sponsor of the study and the sponsor can release it to the public. Sponsors are not given an opportunity to suggest changes in reports. All reviewer comments and SC deliberations remain confidential. The names and affiliations of the report reviewers are made public when the report is released.

Appendix N

Expert Oversight and Review

Oversight Committee:

Richard C. Flagan, California Institute of Technology, CCST Board Member

John C. Hemminger, University of California Irvine, former CCST Board Member
(retired March 2018)

Samuel J. Traina, University of California Merced, CCST Board Member
(Joined March 2018)

Robert F. Sawyer, University of California, Berkeley, External Member

Report Monitors:

Robert F. Sawyer, University of California, Berkeley

Expert Reviewers:

Michael Adewumi, Pennsylvania State University

Charles Anderson, Anderson RNG

Jack Brouwer, University of California, Irvine

Dave Jones, DMJ Gas Marketing Consultants LLC

Sean Mezei, Fortistar

Rob Oglesby, Retired, Former CEC Executive Director

Jeffrey Rosenfeld, ICF

Rishi Shukla, Archer Daniels Midland

Jeffrey Wetzel, Snap Energy Systems LLC

Appendix O

Full List of Findings, Conclusions, and Recommendations

Findings, Conclusions and Recommendations related to Heating Values

Finding 1: California allowed a lower heating value – 970 BTU/scf – before 2006.

Finding 2: Other states have lower minimum heating values, as low as 950 BTU/scf. The most common minimum HV requirement in the United States is approximately 970 BTU/scf.

Finding 3: The NGC+ Interchangeability Work Group determined that the Wobbe Number is the most efficient and robust single interchangeability index. Their interim guidelines specified a Wobbe Number range of +/- 4% from the local historical average gas. These guidelines were implemented in Rule 30 and, along with the AGA lifting index, are sufficient to define the range of interchangeable biomethane supplies.

Finding 4: There is substantial variability in upgrading cost across varying sources of biogas and varying vendor-supplied estimates. Seven companies, out of 28 initially contacted, provided detailed cost estimates. Mean estimates of upgrading biogas to biomethane, at 970 BTU/scf, range from \$5 to \$18 per MMBTU. The mean estimates of the additional cost of upgrading to 990 BTU/scf rather than 970 BTU/scf are between \$1 and \$5 per MMBTU.

Conclusion 1: The scientific modeling by authors of this paper and in the literature provide evidence that keeping the current minimum WN and relaxing the HV specification to a level near 970 is unlikely to impact safety or equipment reliability.

Conclusion 2: The admittedly incomplete available evidence suggests that relaxing the HV specification to a level near 950 could affect safety.

Recommendation 1: Keep the WN minimum requirements as they are now.

Recommendation 2: Reexamine regulations on HV minimum levels. Initiate a regulatory proceeding to examine the option of allowing biomethane satisfying the current WN limits and all other requirements, but with a heating value as low as 970 BTU/scf.

Findings, Conclusions and Recommendations related to Siloxanes

Finding 5: Because of their broad use, siloxanes are often found in wastewater and landfills and therefore can be in biomethane produced from wastewater treatment plants and landfills.

Finding 6: Siloxanes are not expected to be present in dairy waste, agriculture waste, and forestry residues.

Finding 7: During combustion, siloxanes are fully oxidized and form silica molecules. Deposition of silica can cause a wide variety of operational issues and hazards. Possible direct health impacts are not well known and need more study.

Conclusion 3: Current California siloxane specifications are based on very little data and involve broad extrapolation from that data.

Finding 8: Siloxanes can be removed before injections into pipelines at relative small cost, but possibly not to the current California standards.

Finding 9: At present, no standardized measurement protocol exists for dependable measurement for the specification of 0.1 mg Si/m³. Several testing laboratories claim detection limits of 0.1 mg Si/m³ or lower. However, we have not been able to independently test these claims.

Finding 10: ASTM International is developing a standard test method for siloxane measurement and quantification in order to determine the gas-phase concentrations of volatile silicon compounds in the ppbv to ppmv concentration range. Once done, it will be tested by labs over a five-year period.

Conclusion 4: There is not enough information available now to determine whether 0.1 mg Si/m³ is too stringent or not stringent enough to meet safety requirements.

Conclusion 5: Some sources are very unlikely to have siloxanes – e.g., dairies or agricultural waste. These sources could be held to a reduced and simplified verification regime to avoid unnecessarily encumbering sources that do not produce siloxanes.

Conclusion 6: Additional testing and experimentation are required in order to more rationally set a siloxane standard in the future.

Conclusion 7: There is not enough scientific evidence to support an increase or a decrease in maximum allowable concentrations.

Recommendation 3: Support a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes.

Recommendation 4: There is not enough evidence to recommend any changes to the maximum allowable siloxanes concentration at this time.

Recommendation 5: Consider the development of a reduced and simplified verification regime for sources that are very unlikely to have siloxanes, such as dairies or agricultural waste.

Recommendation 6: Monitor the ASTM International process to adopt and test a standard test method for siloxanes.

Recommendation 7: Use the learnings from the siloxane research and the ASTM International process to revisit the siloxane maximum standards once more complete information becomes available.

Findings, Conclusions related to Alternatives to Pipeline Transportation

Finding 11: Blending of upgraded biogas with natural gas in or at the pipeline might allow safe pipeline movement of upgraded biogas that does not meet all specifications, but only under very specific conditions, typically dictated by the pipeline company.

Conclusion 8: An important question for the State of California is under what conditions biogas should be upgraded to biomethane and the biomethane transported on common-carrier pipelines. An alternative is to use upgraded biogas (not meeting all pipeline standards) or biomethane on-site, typically for generating electricity.

Findings, Conclusions, Recommendations related to Market Distortions Stemming from Existing California and Federal Regulations

Finding 12: Financial incentives through the California Low Carbon Fuel Standard (LCFS) and the Federal Renewable Fuel Standard (RFS) programs can be a factor of up to 18 times greater than the commodity value of the biomethane itself. Both the LCFS and RFS programs have volatile prices; thus investments are subject to substantial regulatory risk.

Finding 13: The producer of biomethane can stack financial incentives; they can receive both the financial incentives of the LCFS and those of the RFS if it can be demonstrated that the biomethane is used for transportation. If it is used for purposes other than transportation, neither incentive is available. Stacking may result in total magnitude of regulatory incentives greater than initially intended by either the State of California or the United States government.

Conclusion 9: The differential treatment under the Federal Renewable Fuel Standard program creates a substantial market distortion away from electricity generation and toward direct use of biomethane. In addition, if CARB regulations allow electricity to obtain only cap-and-trade credits rather than LCFS credits, that regulatory difference adds an additional substantial financial market distortion away from electricity generation.

Recommendation 8: State and Federal agencies should examine whether the substantial differences in incentives for various uses of biogas and biomethane are consistent with the State and Federal policy intentions.

Appendix P

Acknowledgements

The steering committee and authors of the report would like to acknowledge the support and hard work of many individuals who were essential to the success of this report.

Dr. Amber Mace, CCST project director, oversaw the development and implementation of the study. Dr. Sarah Brady, CCST project manager extraordinaire, coordinated all of the experts, contracts and project details as well as the day-to-day activities to deliver the project on time and under budget. Puneet Bhullar, CCST project assistant, and Dr. Mikel Shybut, CCST project associate, provided exceptional organizational support at every stage. Donna King, CCST accountant, oversaw the financial aspects of the contract. Other staff at CCST were also invaluable, in particular, CCST's Executive Director Dr. Susan Hackwood as well as Dr. Christine Casey, Ben Landis, Annie Pierce, Dr. Brie Lindsey and Christy Shay.

Staff and appointees of the California Executive Branch provided vital information and support for the project. Our contacts at the California Public Utilities Commission (CPUC) were essential to the inception and contract management of the project, particularly Eugene Cadenasso, Franz Cheng, Carlos Velasquez, and Jamie Ormond. Many diligent government employees and appointees from the California Energy Commission (CEC) and the CPUC furnished essential data used in this report.

We also wish to acknowledge the oversight committee for their guidance in assembling and appointing the steering committee: Richard Flagan, John Hemminger, Sam Traina and Bob Sawyer. Bob Sawyer also served as the report monitor. We thank the peer reviewers who provided insightful comments on the draft report: Michael Adewumi, Charles Anderson, Jack Brouwer, Dave Jones, Sean Mezei, Rob Oglesby, Jeffrey Rosenfeld, Rishi Shukla, and Jeffrey Wetzel.

Without the contributions of these individuals and many more, this report would not have been possible.



CCST
CALIFORNIA COUNCIL ON
SCIENCE & TECHNOLOGY

CCST is a nonpartisan, nonprofit organization established via the California State Legislature – making California's policies stronger with science since 1988. We engage leading experts in science and technology to advise State policymakers – ensuring that California policy is strengthened and informed by scientific knowledge, research, and innovation.

CCST operates in partnership with, as well as receives financial and mission support, from a network of public and private higher-education institutions and federally funded laboratories and science centers:

The University of California System
California State University System
California Community Colleges
California Institute of Technology
Stanford University
NASA Ames Research Center
NASA Jet Propulsion Laboratory
Lawrence Berkeley National Laboratory
Lawrence Livermore National Laboratory
Sandia National Laboratories-California
SLAC National Accelerator Laboratory
National Renewable Energy Laboratory

To request additional copies of this publication, please contact:

CCST
1130 K Street, Suite 280
Sacramento, California 95814
(916) 492-0996 • ccst@ccst.us
www.ccst.us • facebook.com/ccstorg • @CCSTorg

BIOMETHANE IN CALIFORNIA COMMON CARRIER PIPELINES:
ASSESSING HEATING VALUE AND MAXIMUM SILOXANE
SPECIFICATIONS – AN INDEPENDENT REVIEW OF
SCIENTIFIC AND TECHNICAL INFORMATION
(FULL REPORT)
California Council on Science and Technology • June 2018

