Comments of FuelCell Energy, Inc. on Draft Aliso Canyon Methane Leak Climate Impacts Mitigation Program

Prepared for:
California Air Resources Board
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Introduction

FuelCell Energy, Inc. (FCE) applauds the recommended approach of the California Air Resources Board (ARB) to achieve full mitigation of the climate impacts of the Aliso Canyon natural gas leak. In particular, we appreciate ARB's primary emphasis on reducing methane emissions from California's agriculture and waste sectors, and the corresponding opportunity to convert this biogas into biomethane to be directed towards several beneficial uses, including renewable hydrogen production (P. 11).

To achieve these objectives, FCE believes that the mitigation program could take advantage of the existing Southern California Gas Company (SoCalGas) tariff for Biogas Conditioning and Upgrading Services (G-BCUS)[1], as well as potentially utilize the Distributed Energy Resources Services (GO-DERS)[2] tariff.

a. The mitigation program could leverage the SoCalGas G-BCUS shareholder tariff to offset initial capital costs to plan, design, procure, construct, own, operate and maintain biogas conditioning and upgrading equipment on SoCalGas customer premises. Mitigation funds should be limited to biogas conditioning and upgrading equipment in California, with an emphasis on those areas most impacted by the Aliso Canyon leak.
b. In addition, the mitigation program could potentially leverage the SoCalGas GO-DERS shareholder tariff to offset initial capital costs to plan, design, procure, construct, own, operate, and maintain eligible distributed energy equipment on SoCalGas customer premises.
c. Mitigation funds should focus on project opportunities, such as renewable hydrogen production from Tri-Generation fuel cell systems, which have the greatest impact on reducing carbon emissions, criteria air pollutant emissions, and water consumption from multiple sources.

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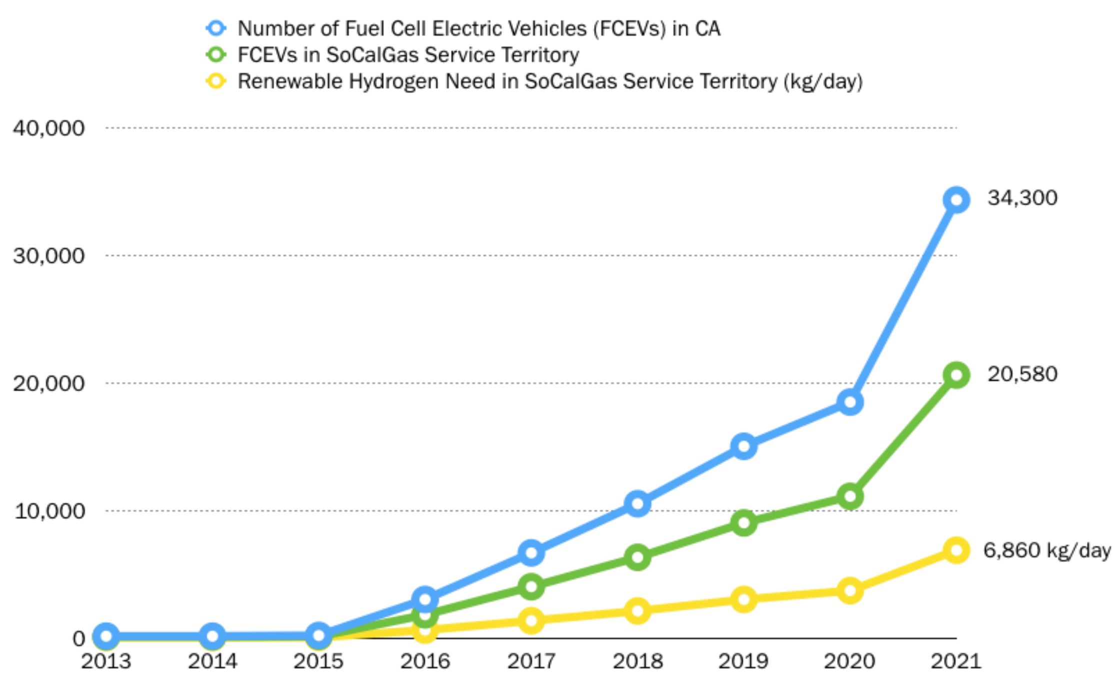
[1] Effective February 21, 2015, the California Public Utilities Commission (CPUC) approved G-BCUS.
[2] Effective October 22, 2015, the CPUC approved GO-DERS. CPUC has limited customer end-use applications to be served by GO-DERS to CHP systems that meet or exceed the GHG emissions threshold set by the Self-Generation Incentive Program (350 kg CO_2/MWh).[2]

Potential Application of Mitigation Program for Renewable Hydrogen Production

An innovative potential use of the Aliso Canyon mitigation program would be to help California achieve a renewable hydrogen fueling solution for Fuel Cell Electric Vehicles (FCEVs). The Governor's office, legislature, California Energy Commission (CEC), and ARB all have made hydrogen infrastructure a key priority for meeting the state's zero emission vehicle goals. Early deployment presents a challenge to the hydrogen FCEV industry because station investment often needs to come before vehicle demand.

Auto manufacturers from around the world have announced plans to commercialize FCEVs and have called for increased investment in refueling infrastructure. Senate Bill 1505 (2006) requires that at least one third of all hydrogen for FCEVs come from eligible renewable resources. According to estimates from the CEC, ARB and California Fuel Cell Partnership (CaFCP), by 2021 over 34,300 FCEVs will be located in California, with approximately 20,580 located in SoCalGas service territory.

Figure 1: FCEV Projection and Renewable Hydrogen Production Needs Through 2021



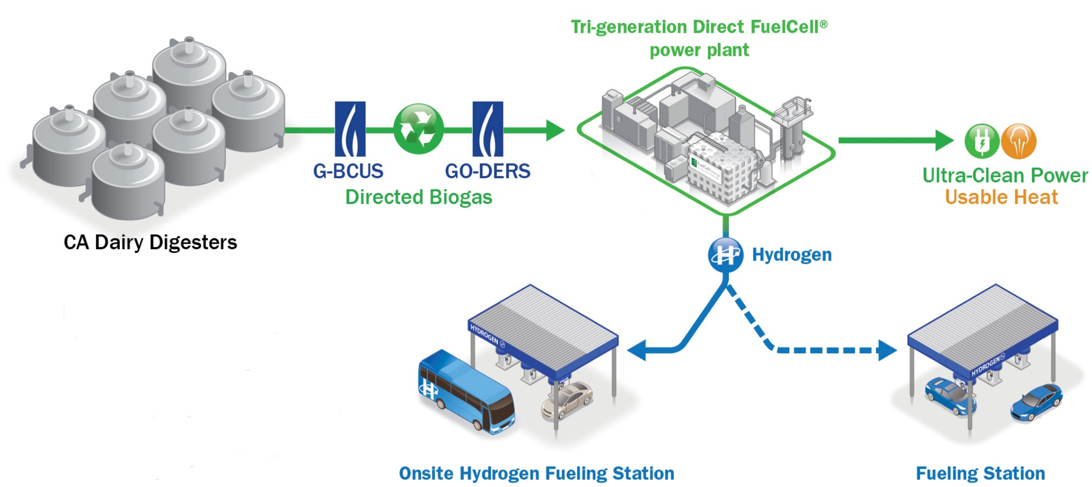
Sources: 2014-15 CARB/CEC ARFVTP reports, CA Fuel Cell Partnership estimates.

Certain Combined Heat and Power (CHP) fuel cells have the technical capability to co-produce renewable hydrogen to fuel these vehicles. One such system from FCE, the Tri-Generation Direct FuelCell® (Tri-Gen), generates approximately 1,200 kilograms per day of hydrogen. Simultaneous with hydrogen production is the generation of approximately 2 megawatts of electric power and 2 million Btu/hour of thermal energy. Tri-Gen CHP fuel cells can provide a local, renewable, cost-effective, and efficient infrastructure bridge for distributed hydrogen production for FCEVs.

In January 2016, ARB's Low Carbon Fuel Standard (LCFS) team completed a life cycle analysis on the Tri-Gen fuel cell system and determined that it has a negative carbon footprint when using biomethane from a water resource recovery facility. According to ARB, using dairy-derived biomethane has the potential for superior environmental benefits. As will be discussed in detail, Tri-Gen is an environmentally superior use of directed biomethane when compared to alternatives such as Renewable Natural Gas (RNG) for vehicles, hydrogen generation through Steam Methane Reformation (SMR), or CHP combustion systems for electricity and heat generation.

We propose potential use of the G-BCUS tariff to provide directed biomethane for five (5) Tri-Gen fuel cell systems, which can be deployed using the GO-DERS tariff or third-party financing.

Figure 2: Tri-Gen Deployment using Directed Biomethane



In addition to reduced carbon emissions, Tri-Gen produces hydrogen without using water, which is consumed in both water electrolysis and conventional SMR. The Tri-Gen system uses waste heat and water byproducts produced by the fuel cell during power generation to make hydrogen efficiently and without the need for external water consumption. In fact, Tri-Gen is a *net producer* of water. During the process of hydrogen recovery, water created by the Tri-Gen fuel cell system's reactions is condensed and separated for other purposes. This leads to net water production of 0.6 million gallons per year for each Tri-Gen system.

E3 Cost-Benefit Analysis

As Appendix 1 to these comments, we attach independent analysis performed by Energy & Environmental Economics (E3) that offers an objective cost-benefit assessment of Tri-Gen. According to E3, the deployment of five (5) Tri-Gen systems in SoCalGas service territory could mitigate all of the emissions from the Aliso Canyon leak in less than seven (7) years of operation.

Moreover, under current LCFS and SGIP incentives, Tri-Gen systems are financially beneficial to the host. At a directed biomethane price of $13/MMBtu, LCFS and SGIP are not necessary to match the costs of the infrastructure and renewable fuel needs. With current availability of LCFS and SGIP, it would take a biomethane price of over $24/MMBtu to cause a negative financial outcome from a Tri-Gen project.

Accordingly, an effective and efficient use of mitigation program funds would be to offset initial capital costs associated with biogas conditioning and upgrading equipment. Such an offset would decrease the price of corresponding directed biomethane, improve the financial benefits of resulting Tri-Gen projects, and eliminate the impact of regulatory and policy uncertainty around LCFS and SGIP.

Comparative Environmental Analysis

In addition to the E3 analysis, we have compared the environmental benefits of Tri-Gen to other alternatives that ARB may be considering. For purposes of this comparison we focus on three other ways to potentially use directed biomethane from in-state resources: 1) RNG for internal combustion engine vehicles (ICEVs), 2) renewable hydrogen production using SMR, and 3) conventional CHP combustion projects. Our analysis concludes that Tri-Gen offers three superior environmental attributes: 1) reduced carbon emissions, 2) reduced criteria air pollutant emissions, and 3) reduced water consumption.

Carbon Emissions Comparison

Tri-Gen offsets more carbon emissions than alternatives. This is largely because hydrogen fuel cell propulsion systems offer superior efficiency compared to combustion technologies. The benefits of fuel cells are made clear by ARB's Energy Economy Ratio (EER) for FCEVs operating on hydrogen when compared with ICEVs running on RNG. The EER accounts for the differing energy efficiency of powertrains that use various fuels. Relative to gasoline for ICEVs, FCEVs using hydrogen have an EER of 2.5. On the other hand, ICEVs using natural gas (including RNG) have an EER of 1.0, the same as gasoline. Therefore, using biomethane for renewable hydrogen production is inherently more efficient than using the same biomethane as direct transportation fuel for ICEVs.

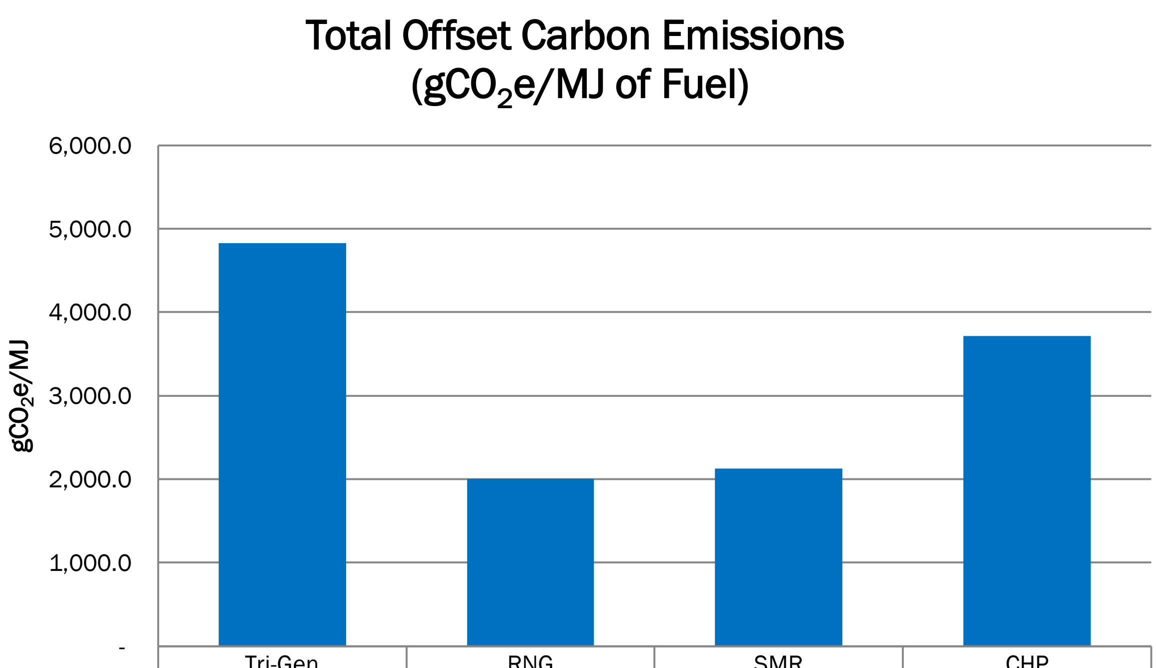
In addition, per kilogram of hydrogen produced, Tri-Gen offers lower carbon intensity compared to SMR. Both Tri-Gen and SMR combine steam and methane in a high-temperature endothermic reaction. In Tri-Gen, exothermic heat from the fuel cell reactions is used to drive the endothermic steam reformation reaction to produce hydrogen. In SMR, on the other hand, additional fuel must be combusted to generate the required heat to drive the same reactions. This results in a higher efficiency and lower carbon intensity for Tri-Gen.

Finally, in addition to producing electricity and heat, Tri-Gen produces hydrogen that offsets transportation-related carbon dioxide from the production of gasoline. As a result, Tri-Gen provides more significant carbon reductions than combustion CHP systems.

Should ARB allow Aliso Canyon mitigation projects using the GO-DERS tariff, SoCalGas could use the tariff to operate conventional CHP assets, such as internal combustion engines, gas turbines, or microturbines. Tri-Gen offers important carbon emissions reduction benefits that combustion CHP resources do not.

A comparison of total offset carbon emissions is summarized in Figure 3, below.

Figure 3: Carbon Emissions Comparison of Tri-Gen, RNG, SMR, and CHP[3]



	Tri-Gen	RNG	SMR	CHP
gCO2/MJ	4,826.9	2,006.9	2,128.5	3,714.6

[3] Total offset carbon emissions (gCO_2e/MJ of fuel) for CHP assumes that electricity produced by the CHP system is used in Battery Electric Vehicles. This assumption allows for a comparison of CHP to other alternatives on a MJ of transportation fuel basis.

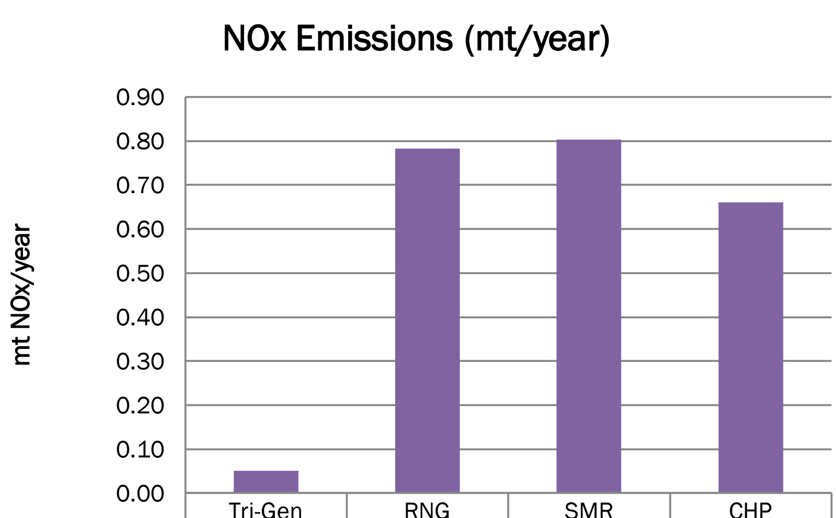
Criteria Air Pollutant Emissions Comparison

Renewable hydrogen production using Tri-Gen also will reduce criteria pollutant emissions such as NOx. The Tri-Gen system generates electricity, heat and hydrogen with extremely low criteria pollutant emissions. The resulting renewable hydrogen will then be used in FCEVs with no criteria pollutants. Therefore, Tri-Gen reduces criteria air pollution from stationary power generation and transportation sources. In addition, waste heat from a Tri-Gen system can be used to offset use of conventional gas boilers for thermal applications, such as steam and hot water.

Unlike Tri-Gen, hydrogen production from SMR relies on an external burner that takes a significant percentage of available fuel to create the necessary steam to drive the reformation reaction. This burner produces significant emissions of NOx and related criteria air pollutants. Tri-Gen, on the other hand, does not rely on an external burner due to the water and thermal energy provided by clean exothermic fuel cell reactions.

Like Tri-Gen, conventional CHP also produces electricity and heat. However, CHP relies on high-temperature combustion, which produces criteria air pollutants such as NOx. A comparison of NOx emissions are summarized in Figure 4, below.

Figure 4: Criteria Air Pollutant Emissions Comparison of Tri-Gen, RNG, SMR, and CHP



	Tri-Gen	RNG	SMR	CHP
mt NOx/year	0.05	0.78	0.80	0.66

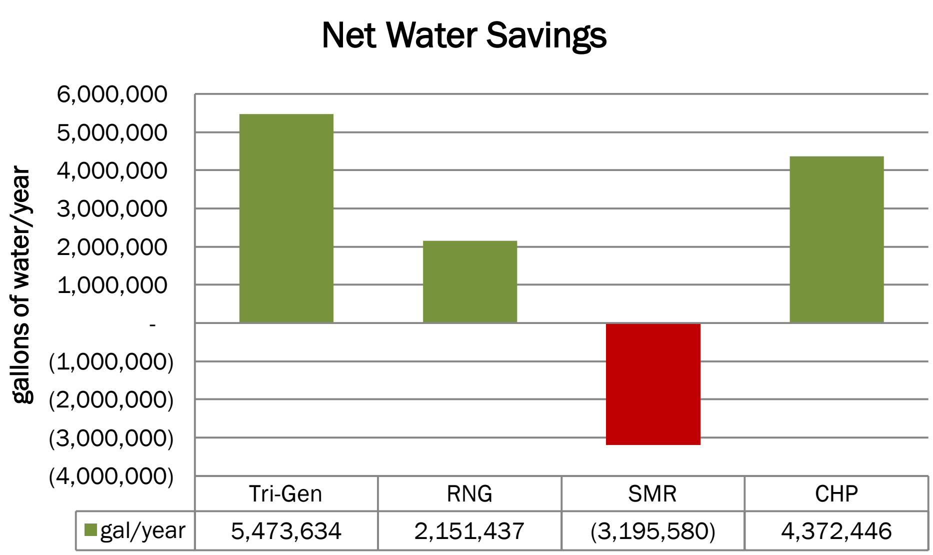
Water Consumption Comparison

Because of Tri-Gen's unique technical attributes, each Tri-Gen system saves over 5 million gallons per year of water versus conventional methods of generating the same electricity, heat and hydrogen. This is significant given state water conservation goals.

Both Tri-Gen and SMR combine steam and methane in a high-temperature endothermic reaction to produce hydrogen. Tri-Gen, however, uses the water already produced from exothermic reactions within the fuel cell system. This means that no external water source is needed. The result is a notable difference in water consumption. While SMR requires large amounts of water to create steam, each Tri-Gen system results in 0.6 million gallons per year of excess water that can be used for other purposes.

While RNG offsets some water from gasoline production, Tri-Gen offers far superior water consumption benefits. Tri-Gen also offers water consumption benefits versus combustion CHP systems. While both Tri-Gen and CHP offset electricity from the grid, Tri-Gen is also a net producer of water. During the extraction of hydrogen from the fuel cell process, fuel cell product water is also extracted. CHP systems, on the other hand, reject all of their water as dilute vapor in the system exhaust. Net water savings from Tri-Gen are summarized in Figure 5, below.

Figure 5: Water Savings Comparison of Tri-Gen, RNG, SMR, and CHP



Flexible Renewable Hydrogen Production

In order to meet the statutory requirement of Senate Bill 1505, one third of all hydrogen for FCEVs must come from eligible renewable resources. As we have discussed, ARB and CaFCP have estimated that by 2021, SoCalGas service territory will have 20,580 FCEVs. Accordingly, the projected need for renewable hydrogen in 2021 for FCEVs will be at least 6,800 kilograms per day (to meet the 33% renewable requirement). Each Tri-Gen system produces 1,200 kilograms per day, meaning that deployment of five Tri-Gen systems by 2021 within SoCalGas service territory would provide most of the necessary renewable hydrogen for the region. Large-scale SMR could also meet this need with directed biomethane, but at the expense of the water consumption and criteria pollutant emissions discussed above, plus added emissions from longer distance transportation.

Timing and Location Considerations

FCE agrees with ARB that projects under the mitigation program should be subject to a time limit. As ARB states, “a time limit will ensure prompt action is taken to implement the mitigation program, facilitate the monitoring of program progress, lessen the administrative costs associated with program implementation, and avoid the contingencies that may complicate or frustrate distant emission reductions” (P. 7).

Tri-Gen systems can be in service within one year of commencement of construction. Site locations can be optimized throughout SoCalGas service territory to emphasize primary need areas. Tri-Gen locations within SoCalGas territory should be based on two factors: 1) the geographic areas with the highest expected number of FCEVs and hydrogen stations, which will minimize hydrogen transportation costs (hub and spoke model), and 2) the local communities most impacted by the Aliso Canyon leak.

Conclusion

Tri-Gen systems help California towards several policy goals and mandates, such as renewable hydrogen production, renewable electricity production, CHP deployment, reduced greenhouse gas emissions, reduced criteria air pollutants, and reduced water consumption. Alternatives do not offer a similar scope of responsive policy attributes.

Using the Aliso Canyon mitigation program to accelerate the production of renewable hydrogen using Tri-Gen will provide a cost effective, responsive, and innovative means to fully mitigate Aliso Canyon's methane emissions while protecting ratepayers and assisting with a variety of policy objectives.

Sincerely,

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Appendix 1
E3 Cost-Benefit Analysis

Costs and Benefits of Tri-Gen Fuel Cell Technology

Prepared for:
FuelCell Energy

March 2016

Energy+Environmental Economics

Costs and Benefits of Tri-Gen Fuel Cell Technology

Prepared for:
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March 2016

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Table of Contents

1 Background

FuelCell Energy, Inc. (FCE) engaged Energy + Environmental Economics to conduct a financial and environmental analysis of the use of dairy biomethane with their Tri-Generation (Tri-Gen) fuel cell technology in Southern California Gas Company (SoCalGas) territory. Running a Tri-Gen fuel cell on biomethane significantly decreases the environmental impact of electricity and heat production on site, generates renewable hydrogen, and creates an opportunity for utilization of biomethane, a potent greenhouse gas, which would otherwise be vented.

We evaluated two different scenarios as a part of this effort, (1) a baseline scenario which represents the status quo, and (2) an alternative scenario where dairy biomethane is used in FCE's Tri-Gen technology at a large commercial and industrial customer site (e.g. hospital, office, etc.), in this document referred to as the "host."

Our mitigation scenario assumes that raw biogas is collected at the dairy, conditioned and upgraded to highly concentrated biomethane, and then injected into the SCG pipeline as directed biogas.

FCE's Tri-Gen technology uses biomethane as a fuel, and generates electricity, recoverable heat, and hydrogen. We analyzed the economics of the technology from the perspective of the host, and calculated the net annual emissions savings from the operations of the fuel cell.

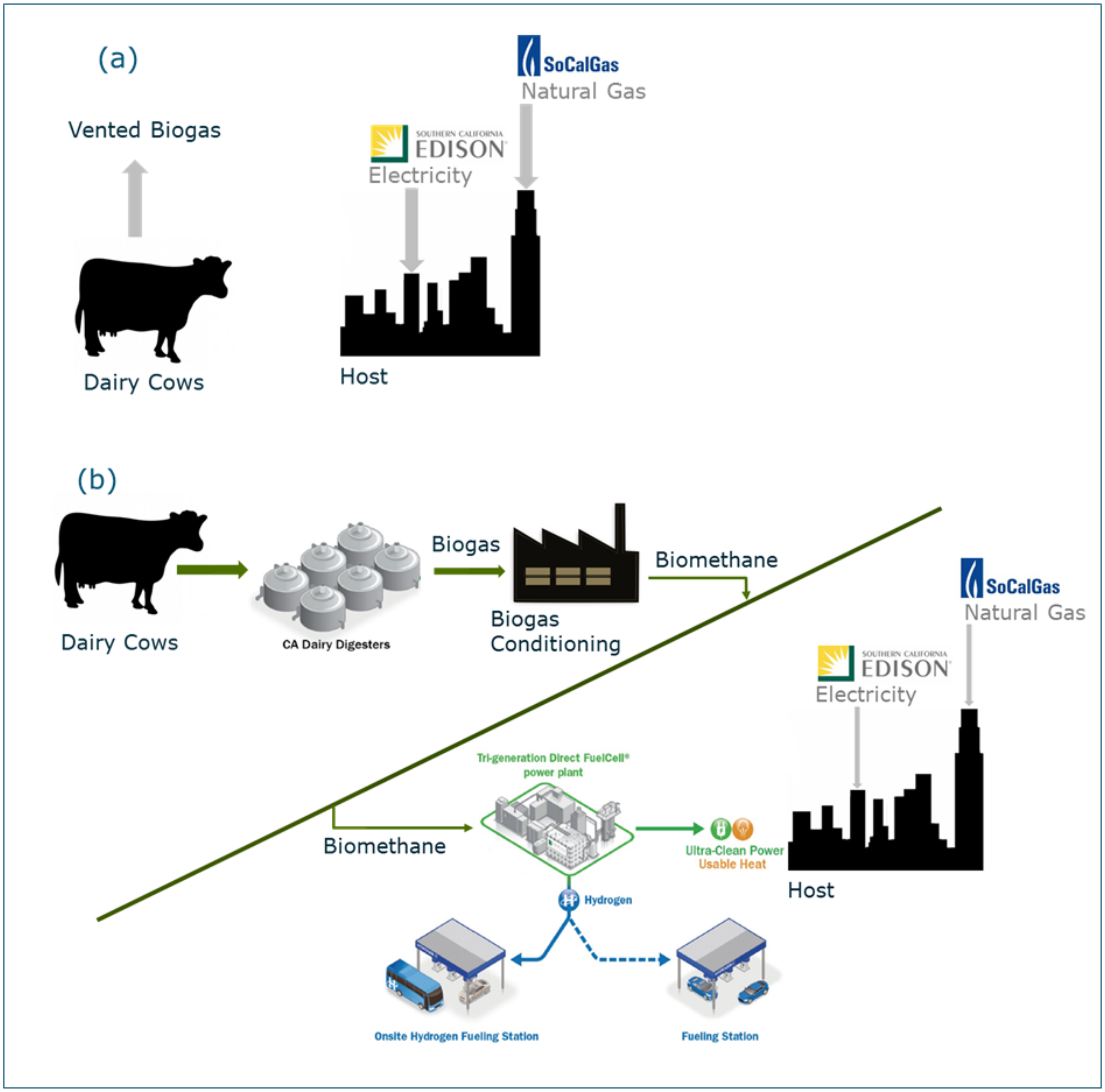

Figure 1: Illustration of (a) Baseline and (b) Proposed Tri-Gen Fuel Cell Scenario

Table 1: Scenario Components

	Baseline	Tri-Gen + Biomethane
Host electricity source	California electric grid, Southern California Edison (SCE) territory	California electric grid (SCE territory) and electricity produced by the fuel cell
Host heat source	Natural gas transported using SoCalGas pipeline infrastructure	Natural gas transported using SoCalGas pipeline infrastructure and recovered heat from the fuel cell
Methane from dairies	Vented into the atmosphere	Upgraded to pipeline-grade biomethane and directed for use in the fuel cell
Downstream transportation fuel	Gasoline[1]	Hydrogen

1. The Baseline Scenario assumes dairy methane is vented, and the host uses electricity and natural gas from local utilities for energy needs.

2. The Alternative Scenario assumes an FCE Tri-Gen fuel cell will be installed at the host to offset electric and heating needs with directed dairy biomethane. The Tri-Gen technology will additionally produce hydrogen to be sold for transportation purposes. The fuel cell will be financed through the new SoCalGas GO-DERS tariff.

[1] Baseline assumption is that gasoline is used as transport fuel.

GO-DERS is a tariff offered by SoCalGas to customers with Distributed Energy Resources (DER) located on their premises.[2] Under this tariff, SoCalGas is responsible for the ownership, operations and maintenance of the DER equipment and facilities, and a service fee is negotiated between the customer and SoCalGas to recover the capital and operating costs. FCE's Tri-Gen technology with a rated power output of 2.35 MW would be eligible for the GO-DERS tariff, which has a size cap of 20 MW.

[2] The DERS tariff is documented further online: https://www.socalgas.com/regulatory/A1408007.shtml

2 Methodology

In order to analyze the potential benefits of the Tri-Gen technology (key assumptions in Table 2), we examined both financial and environmental impacts of the fuel cell compared to current operating procedure. For illustration purposes, we modeled a large non-residential customer that has both electric and heating (gas) loads. The electric and gas requirements offset by the fuel cell were less than the total demand in every hour, resulting in no net exports to the grid (meaning the fuel cell is partially offsetting grid requirements).[3]

Table 2: Key technical parameters of the FCE Tri-Gen technology

Technology Assumptions	Value
System size (kW)	2,350
Capital costs ($)	$20,281,000
Fixed O&M costs ($/year)	$1,175,000
Capacity factor (%)	95%

[3] Heating and electric loads were pulled from EIA online database, found online: http://en.openei.org/datasets/files/961/pub/COMMERCIAL_LOAD_DATA_E_PLUS_OUTPUT/USA_CA_Los.Angeles.Intl.AP.722950_TMY3/

This analysis was conducted using assumptions from FCE, literature review, and subject-matter experts. The two-part analysis is summarized below.

2.1 Financial Analysis

In order to evaluate the benefits to customer, we compared their avoided electricity and heating costs to the service fee paid to SoCalGas, and the cost of purchasing and transporting biogas from the dairy. With the use of Tri-Gen technology, the host can also earn revenues through the sale of hydrogen, and be eligible for Low Carbon Fuel Standard (LCFS) credits in California. Table 3 summarizes the key costs to the host, and the value streams that offset the payments.

Table 3: Key Benefit-Cost Analysis Components

Benefits	Costs
• Avoided electricity purchase costs • Avoided gas heating expenses • Value from hydrogen production from (1) revenues from sales of hydrogen fuel, (2) monetary value from LCFS credits	• Costs of biogas purchase from dairy (including cost to capture and condition the fuel) • Costs of transport of biogas using SoCalGas pipeline infrastructure • GO-DERS monthly Service Fee payments to SoCalGas

In order to calculate the bill savings for the customer, we assumed the customer to be served on SCE's TOU-8[4] rate schedule. For calculation of avoided heating expenses, we assumed a gas

[4]We assumed the customer to be non-residential, with a monthly peak demand of 500 kW or greater. The applicable tariff can be found here: https://www.sce.com/NR/sc3/tm2/pdf/ce54-12.pdf

price of $2.78/MMBtu, with a delivery charge of $1.11/MMBtu paid to SoCalGas for transportation and delivery of the gas to the host.[5]

We used a directed biomethane market price of $13/MMBtu and a hydrogen price of $4.5/kg.[6] The biomethane price used in the analysis is assumed to reflect the cost of conditioning dairy methane and upgrading it to the standards required for pipeline injection and ultimate consumption at the site of the fuel cell.

For the estimation of monthly GO-DERS payments, assumed a traditional utility financing model using SoCalGas's cost of capital and SGIP credits for the fuel cell. We utilized the E3 financial proforma model to levelize the capital expenditures and operating costs provided by FCE over the 20-year life of the fuel cell, assuming the currently authorized weighted average cost of capital for the utility to be 8.02%. We assumed that the eligibility of the fuel cell for the Self-Generation Incentive Program (SGIP) would reduce the capital costs by $3.5M.[7]

The renewable hydrogen generated by the fuel cell is assumed to be eligible for the Low Carbon Fuel Standard (LCFS) credits. The trajectory for the value of the LCFS credits are represented in Table 4, and highlight the high value given to renewable hydrogen produced from dairy methane. Beyond 2020, we assumed that the value of LCFS credits remains constant at 2020 levels.

[5] We assumed the customer would buy the natural gas at the hub market price and pay transportation and delivery charges to SCG as per the tariff found here: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-I.pdf

[6] Hydrogen and directed biomethane prices provided by FCE.

[7] Capital expenses, O&M expenses, and SGIP rebate quantity provided by FCE.

Table 4: LCFS Credits Trajectory[8]

Year	LCFS credits generated per kg of H_2	Value of LCFS credits per kg of H_2
2015	0.061262	$7.658
2016	0.060977	$7.622
2017	0.060544	$7.568
2018	0.060111	$7.514
2019	0.059678	$7.460
2020	0.059104	$7.388

2.2 Environmental Analysis

In addition to the financial analysis, we calculated the net emissions savings that would result with the displacement of grid electricity and gas heating by use of the electricity generated and the heat recovered from the fuel cell, as well as due to the downstream gasoline offset by the use of hydrogen as transportation fuel. The carbon dioxide and methane savings are summarized in Table 5.

[8] Values provided by FCE.

Table 5: Emissions savings from operation of fuel cell

Emissions Savings	Rationale
Avoided grid carbon dioxide emissions	The carbon dioxide emissions intensity of electricity from California grid is higher than the emissions associated with the electricity produced by the fuel cell due to the biogenic fuel source
Avoided carbon dioxide emissions due to thermal recovery from fuel cell for heating	The carbon dioxide emissions associated with heat recovered from the fuel cell are lower than the emissions resulting from combustion of natural gas for heating purposes
Carbon dioxide emissions savings resulting from reduced gasoline use in transportation	The use of renewable hydrogen as transportation fuel is expected to offset gasoline as a fuel, resulting in carbon dioxide savings in transportation
Avoided methane emissions	By use of dairy biomethane in the fuel cell, the venting of the potent greenhouse gas can be avoided

In order to calculate the grid emissions savings by the fuel cell, we used a value of 350 kgCO_2/MWh for the carbon dioxide emissions intensity of the current California grid.[9]

The emissions from the fuel cell are 537 kg CO_2/MWh of electricity produced. However, the CO_2 produced is formed from dairy biomethane, a biogenic source of carbon, which for accounting purposes are treated as zero.

For calculation of avoided carbon dioxide emissions due to reduced combustion of gas for heating, we assumed that 66.28 kg of carbon dioxide emissions were offset for every MMBtu of

[9] 350 kg/MWh CPUC's estimate of marginal generator emissions. Appendix B, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K044/156044151.PDF

heat recovered from the fuel cell.[10] In addition, we accounted for the reduced transportation emissions resulting from the displacement of gasoline by renewable hydrogen as a fuel. We assumed an avoided carbon dioxide emissions factor of 178 kg for every MMBtu of hydrogen produced by the fuel cell.[11]

We assumed that the methane used as fuel in the fuel cell would otherwise be vented – therefore, the annual methane consumption by the fuel cell was the amount of avoided methane emissions. Hence the resulting methane savings from the operation of the fuel cell are 3,207.41 metric tonnes.[12] Using the value of 84 as 20-year Global Warming Potential (GWP) of methane, we converted the overall emissions savings to an annual estimate of CO_2e avoided.[13]

[10] Provided by FCE. Assumes natural gas carbon content to be 117 lbs/MMBtu, and a boiler efficiency of 80%.

[11] Provided by FCE. Assumes gasoline carbon content to be 157 lbs/MMBtu, and an energy economy ratio of 2.5.

[12] Hourly methane fuel input provided by FCE to be 5957 kW

[13] This 20-year GWP is the same as the ARB uses in its draft mitigation document. Source: Fifth Assessment Report of the United Nations Intergovernmental Panel on Climate Change

3 Results

3.1 Cost-Benefit Analysis

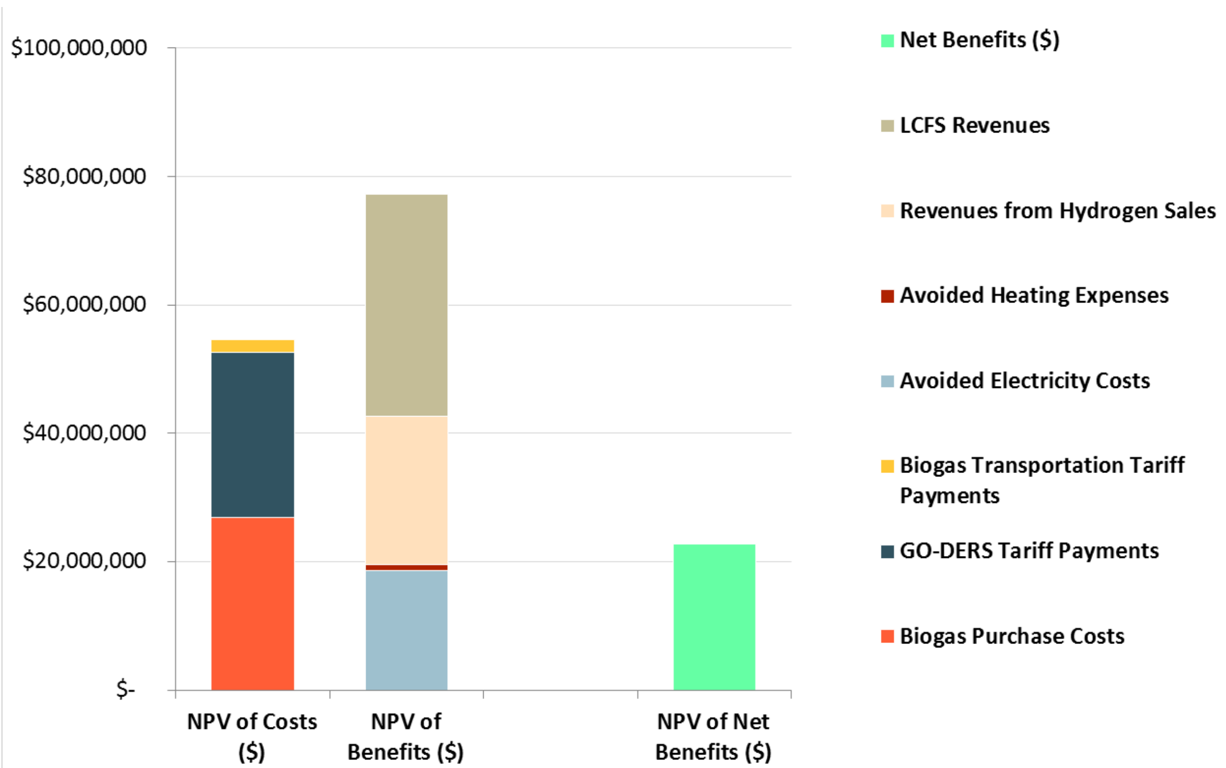

Figure 2: Costs and benefits of biomethane-fueled Tri-Gen technology at host

The key components for the cost-benefit analysis in the base case are summarized in Figure 2. The revenues from the sale of hydrogen as a fuel, and the associated LCFS credits dominate the overall economic benefits. For the base case, the LCFS program is expected to be reauthorized after 2020, and the value of the LCFS credits is assumed to be held constant at 2020 levels. The biomethane price is assumed to be $13/MMBtu, and a higher purchase price would result in diminished net benefits. The heat produced from the fuel cell is relatively small compared to the electric and hydrogen outputs, which is represented in the avoided heating costs.

3.2 Environmental Analysis

The Tri-Gen fuel cell system reduces 16,580 tonnes of carbon dioxide and 3,207 tonnes of methane annually compared to the baseline. Using a GWP of 84 for methane, this amounts to a total of 286,003 tonnes of avoided CO_2e emissions annually per fuel cell, as shown in Table 6.

Table 6: Emissions avoided by each 2.8 MW Tri-Gen fuel cell system

	Avoided metric tonnes/year	Avoided metric tonnes CO_2e/year
Carbon Dioxide Emissions from Electricity	6,504	6,504
Carbon Dioxide Emissions from Heating	1,170	1,170
Carbon Dioxide Emissions from Transportation	8,906	8,906
Methane Emissions	3,207	269,423

To relate the methane diverted from venting at a dairy to usable energy in a fuel cell, we also conducted an analysis of the number of California dairy cows required to run each fuel cell. Dairy cows produce, on average, approximately 30 cubic feet of methane each day from manure.[14] This is equivalent to about 11,000 cubic feet of methane each year, or 0.21 metric

[14] *Biomethane from Dairy Waste: A Sourcebook for the Production and Use of Renewable Natural Gas in California, p.23*

tonnes of methane each year for each cow. Cows produce additional methane from enteric fermentation, but capturing and utilizing this methane is not currently being pursued.

The fuel needs of the Tri-Gen fuel cell are equivalent to approximately 3,200 metric tonnes of directed biomethane per year, which is equivalent to the methane from about 15,000 cows over the course of the year.

California has over 1.7 million dairy cows in the state, over 900,000 of which are located in SoCalGas territory.[15] The average dairy size among SoCalGas territory dairies is about 17,000 cows, which would mean 9 average-sized dairies will be needed to supply one Tri-Gen fuel cell over the course of a year.[16]

One Tri-Gen fuel cell system avoids 3,200 metric tonnes of methane each year from 15,000 cows. The approximately 100,000 tonnes of methane leaked at Aliso Canyon can be avoided by one dairy biomethane Tri-Gen systems over the course of 30 years or 30 projects over the course of 1 year.

By 2021, projected renewable hydrogen demand in SoCalGas service territory for Fuel Cell Electric Vehicles (FCEVs) will support the deployment of five Tri-Gen systems.[17] The deployment of five Tri-Gen systems in SoCalGas service territory could mitigate all of the emissions from the Aliso Canyon leak in less than 7 years of operation.

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[15] CDFA 2015, SCG dairy-producing counties are assumed to include Kern, Kings, Tulare, Imperial, Riverside, and San Bernadino. Source data available online: https://www.cdfa.ca.gov/dairy/dairystats_annual.html

[16] If you assume 10% methane is lost in the process from capture to conditioning, annual fuel cell needs would require 17,000 cows or 10 average-sized dairies

[17] Each Tri-Gen system produces approximately 1,200 kg/hydrogen per day. According to projections from the California Air Resources Board and California Energy Commission, 34,300 FCEVs will be deployed in California by 2021 (source: http://www.energy.ca.gov/2015publications/CEC-600-2015-016/CEC-600-2015-016.pdf). According to the California Fuel Cell Partnership, approximately 60 percent of California FCEVs will be in SoCalGas service territory. Senate Bill 1505 (2006) requires one third of all hydrogen for FCEVs to come from eligible renewable resources. Therefore, assuming each FCEV uses 1 kg/hydrogen per day, by 2021 projected demand for renewable hydrogen in SoCalGas territory will be 6,860 kg/day.

3.3 Cost Sensitivities and Uncertainty

In the process of scoping this analysis, we have identified four key areas of cost uncertainty: (1) the future of LCFS credits after 2020, (2) the continuation of SGIP after 2016, (3) the price of delivered biomethane, which represents the ability of the dairy to produce biomethane at a competitive price, and (4) the purchase price for transportation hydrogen.

We formulated two sensitivities in addition to the original scenario documented in section 3.1 in order to get a range of possible net present valuations that capture the uncertainties in SGIP and LCFS, with assumptions documented in Table 7. There is significant variability in the price of biomethane depending on the waste stream used for its production, and other site specific factors that could impact costs. A price of $13/MMBtu is a conservative estimate of current market prices for directed biomethane, however it may not be representative of biomethane production costs from dairies. Our analysis found that hydrogen price was not as large of a driver as the extension of LCFS credits.

Table 7: Scenario sensitivity assumptions

	Original Scenario	Sensitivity 1	Sensitivity 2
LCFS Credits	LCFS Program reauthorized after 2020, and value of LCFS credits held constant at 2020 levels	LCFS program expires after 2020	LCFS program expires after 2020
SGIP	Tri-Gen eligible for SGIP rebate	Tri-Gen eligible for SGIP rebate	Tri-Gen not eligible for SGIP rebate
Biomethane Cost	$13/MMBtu	$13/MMBtu	$13/MMBtu
Hydrogen Price	$4.5/kg	$4.5/kg	$4.5/kg

The net benefits from the three cases are summarized in Table 8. All cases find that the financial benefits outweigh the costs over the lifetime of the fuel cell.

Table 8: Summary of net benefits for the sensitivities analyzed

		Net Present Value (Million $)		
		Original Scenario	**Sensitivity 1**	**Sensitivity 2**
Costs	Dairy Biomethane	(26.9)	(26.9)	(26.9)
	GO-DERS tariff payments to SCG	(25.6)	(25.6)	(27.8)
	Directed biogas transmission tariff	(2.0)	(2.0)	(2.0)
Benefits	Avoided electricity costs	18.7	18.7	18.7
	Avoided heating expenses	0.8	0.8	0.8
	Revenues from hydrogen sale	23.1	23.1	23.1
	LCFS Revenues	34.7	14.3	14.3
	Net Benefits	**22.7**	**2.3**	**0.1**

4 Conclusions

Under current incentives we conclude that it is cost effective at $22.7 Million dollars over 20 years to run a Tri-Gen fuel cell on directed biogas for services at a large non-residential customer. This is possible through hydrogen revenues and onsite electricity bill savings, in addition to LCFS and SGIP incentives.

The LCFS and SGIP incentive programs are financially beneficial to the host, but at a biomethane price of $13/MMBtu, these programs are not necessary to match the costs of the infrastructure and renewable fuel needs.

We have assumed utility financing for the fuel cell within the DERS tariff, which would imply that SCG will rate-base the asset, and earn a return on it over time. The return that is embedded in the cost-benefit analysis here may be distributed partially or completely to other methane-reduction activities.

In taking this scenario from theory to implementation, the following are additional questions that need to be answered:

1. How will incentive uncertainty affect the NPV of biomethane Tri-Gen fuel cell projects?

    - It is unclear whether the LCFS program will be extended, and how renewable hydrogen from dairy biogas will be compensated after 2020. It is also unclear whether utility-owned distributed energy resources will qualify for SGIP incentives, as utilities have not historically owned distributed generation.

- The LCFS has the greatest effect on financial benefits for these projects, but even without the financial incentives created by these programs, the project can have net benefits.

2. What will be the cost to produce pipeline-quality dairy biomethane in California?

- Producing directed biomethane from dairies is not an established process, and therefore has uncertain associated costs. Capturing biogas at low methane concentrations is more common, but the costs associated with centralized biogas conditioning and upgrading are less predictable and projected to be high cost.

- In our analysis the biomethane price is a proxy for the overall cost to capture, upgrade, and direct the biomethane from dairy waste. Though this price is uncertain, it would take a biomethane price of over $24/MMBtu to cause a negative NPV for this technology configuration.[18]

3. How will biomethane dairy production be implemented in California?

- Section 3.2 highlighted the need to use 9 average-sized dairies to fuel a single Tri-Gen fuel cell for one year. Real world siting of projects will benefit from finding fewer large dairies with optimal waste management practices in close proximity to minimize equipment and transportation costs.

- More research is needed into the implementation and financial barriers at dairies to determine whether additional incentives are required to create expanded markets for dairy biomethane.

[18] Assuming LCFS extension and SGIP incentives