Using a Contracts for Difference Program to Support Dairy Biogas in California

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Introduction

California has been actively pursuing climate change mitigation for more than a decade through a variety of measures. As part of its overall climate strategy, the state is seeking reductions in short-lived climate pollutants, such as methane, through the implementation of the 2016 Senate Bill 1383. This California legislation includes a comprehensive strategy to mitigate methane emissions through the adoption of a set of policies and incentives that could increase the production and use of compressed natural gas (CNG) produced from renewable sources.

As part of the implementation of the 2016 legislation, a provision authorizes the California Air Resources Board (ARB) to develop a pilot financial mechanism to support the production of transportation fuels, including bio-compressed natural gas (bio-CNG), derived from dairy biogas, which is a substantial source of methane emissions in the state. Although other incentives, such as the federal Renewable Fuel Standard (RFS) and California's Low Carbon Fuel Standard (LCFS), support production of dairy biogas and other cellulosic ultralow-carbon fuels, commercialization of these fuels historically has been hampered by economic and policy uncertainty. Introducing a new mechanism for financing ultralow-carbon fuels provides a unique opportunity to build upon existing incentives by improving policy certainty as well as the cost-effectiveness of government spending and generating greater greenhouse gas (GHG) reductions per dollar spent.

The pilot financial mechanisms implemented through Senate Bill 1383 could include Contracts for Difference (CfD), a per-unit price support guarantee described by Pavlenko, Searle, Malins, and El Takriti (2016). The proposed CfD policy would include two components: a price floor, or *strike price*, supported through state funding, as needed. To determine which producers could qualify for support, a competitive auction among potential fuel producers would reward the producer that can offer the lowest viable strike price for its fuel production in the bidding process. That producer enters a contract with the state of California based on a set volume of fuel over 10 years and the strike price, creating a price floor at that price. For the duration of the contract, the state pays the difference between the market value of the fuel, including all applicable policy incentives, and the strike price whenever the market value dips, thereby ensuring that the producer's strike price is always met.

Dairy biogas is a promising source of ultralow-carbon energy in California. Dairy manure biogas systems in the state could produce approximately 200 million gallons of gasoline equivalents (GGE) of fuel annually (Black, 2016). Due to the greater value of GHG emission reductions within the transportation sector and the greater value of incentives for alternative transportation fuels, diverting dairy biogas toward producing transportation fuel in the form of bio-CNG can support higher prices and offer greater returns to investors and dairy farmers compared to its use for heat and power generation (Black & Buckenham, 2017). However, converting dairy biogas into bio-CNG for transportation requires greater upfront investments and capital expenditures than if the biogas were to be used to produce heat and power for

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onsite consumption. Although policy support from the RFS and LCFS should, in theory, help to overcome the greater initial financial burden of creating a bio-CNG project, uncertainty in the value of future policy support as well as future bio-CNG market values can discourage investment. Farmers and other potential investors are likely to discount the value of existing market incentives for alternative fuels because of this political uncertainty, thus reducing the number of financially attractive opportunities for investment and production of dairy biogas-derived fuels. This disconnect between the most likely potential market value of fuels and the "safe" assumption of potential market value creates an opportunity for a supplemental policy such as a CfD to directly mitigate the risk of policy and market changes. A CfD program would pay out only if the market value is lower than the strike price, for example if the RFS or LCFS is eliminated in the future. The program therefore acts as insurance against policy and market risk. If these policies continue to deliver sufficient added value to bio-CNG production and market conditions remain favorable, the CfD program would pay out little or nothing; this program would thus leverage existing policies and pay out only the minimum amount necessary to support additional bio-CNG production.

This working paper uses the analytical approach originally used by Pavlenko, Searle, and Nelson (2017) and Pavlenko et al. (2016) to assess the levelized costs and the potential impact of using CfDs to support bio-CNG production in California. To evaluate the impact of CfDs, we present a cash flow model of hypothetical costs for dairy biogas bio-CNG projects including capital and variable costs to estimate the break-even price for finished fuel to be viable. We then compare these estimates to the market value of bio-CNG in California to project the costs of a CfD program relative to the volumes of fuel supported and their associated GHG benefits.

Methodology

CASH FLOW MODEL

Our analysis estimates the cost of dairy biogas production and then evaluates the cost of CfD support across a given project's lifetime. We evaluate the effectiveness of the CfD policy using the metric of dollars spent per GGE of new production of bio-CNG derived from dairy biogas. This section describes the two components informing this study's analysis. First, we describe the design of the cash flow model used to estimate the production and financing costs for dairy biogas. We then describe the set of inputs and assumptions underlying the policy framework model used to assess CfD support for dairy biogas projects.

The design of the cash flow model for this analysis draws largely upon previous work in Pavlenko et al. (2017), which assesses the potential impact of CfDs on cellulosic ethanol production in California. In this study, the cash flow model incorporates estimates of methane yield in conjunction with estimates of capital, operations, and maintenance costs that together scale in proportion to the size of a given dairy farm. An overview of the assumptions and data used to estimate the cost of dairy biogas production is available in the Appendix.

Our yield and cost estimates are based on a dairy farm with an onsite plug-tank digester and a biogas clean-up, conditioning, and compression system to produce bio-CNG. We assume that the biogas is trucked to an existing well injection site, as is done in a similar project in Wisconsin (Verburg, 2017), and do not factor in the cost of pipeline extensions and interconnection. Our estimates for the number of projects and volumes that could be supported by a CfD program are based on an assumption of 1,250 cattle per farm, which represents an average-sized dairy farm in California (California Department of Food and Agriculture [CFDA], 2017).

We also present estimates of how project cost scales with herd size. For a given dairy farm, we first estimate the total potential bio-CNG yield from onsite biogas production and processing; because bio-CNG is largely methane, we use the methane yield as the basis for our calculations. Methane yield is proportional to the size of the dairy operation, scaling in proportion to the number of dairy cattle at the project site. We use the Intergovernmental Panel on Climate Change (IPCC) methodology for estimating methane emissions from manure management, as shown in Equation 1. The parameters for methane

$$\textit{Methane Yield} = \textit{Dairy Cattle Population} \times VS_e \times TAM \times MCF \times B_0 \qquad \text{(eq. 1)}$$

Where,

- $\mathbf{VS_e}$ is the volatile solids (VS) excretion rate per pound of dairy cattle;
- **TAM** is the typical animal mass;
- **MCF** is the methane conversion factor, referring to the methane production as a share of overall potential methane yield, depending on manure management practices; and,
- $\mathbf{B_0}$ is the methane generation rate per unit of VS

management draw from California-specific data for methane generation from anaerobic digestion at dairy farms provided by U.S. Environmental Protection Agency [EPA] (2011). Further detail on this study's methodology for estimating methane yields is provided in the Appendix.

The cash flow model aggregates the net present value of all costs attributable to CNG production based on the costs incurred at different farm sizes. The model assumes that for a given facility to be a successful investment, it must generate sufficient cash flow to not only pay off interest, principal, and operating expenses, but also to generate profit. The debt-service coverage ratio (DSCR, the ratio of net income to debt service), generally must exceed 1 for a project to pay off its expenses; a higher value makes it easier for that project to obtain a loan (See Equation 2). The cash flow model assumes a DSCR of 1.3, a lower-range estimate that factors in the stabilized income from the CfD policy. As the perceived risk of a given project increases, a DSCR would need to be higher to reassure investors. The internal rate of return (IRR), which reflects the profitability for a given project relative to its initial investment, is approximately 10%; the modified IRR, which factors in financing rates (8%) and a reasonable reinvestment rate tied to treasuries (approximately 2%), is approximately 6%.

The net income from a theoretical dairy biogas project is calculated based on the following components:

Capital expenditures (CAPEX): CAPEX refers to the sum of capital expenditures for the project—generally the physical components of the project, such as land, equipment, and construction. This includes both the anaerobic digester and the CNG conditioner. CAPEX is assumed to equal the value of the principal for the project for the purposes of determining debt and interest.

Interest: This refers to the interest paid to service the initial debt taken on to pay the CAPEX. Because the value of the project is relatively small (i.e., under $5 million), we assume that the entire CAPEX is financed through debt rather than equity.

Transport costs: The cost of transporting CNG from the dairy farm's onsite biogas conditioner to the point of sale.

Operation & maintenance costs: This cost category includes all other ongoing expenses incurred annually to pay for employee salaries, maintenance, and other overhead.

Total fuel production: This includes all sales from fuel production over the 15-year life of the project, at the strike price.

Taking into account the previous variables, the calculation to determine the total fuel sales for a given project's fuel production is shown in Equation 3. Using the rest of the known variables above as model inputs, the cash flow model solves for the present value of the total lifetime fuel sales for each project. From there, the strike price is calculated by dividing the net present value of the project's total CNG sales throughout a project's 15-year life by the total volume of CNG production during that time.

$$\text{Debt Service Coverage Ration} = \frac{\text{(Net Income)}}{\text{(Total Debt Service)}} \qquad \text{(eq. 2)}$$

$$\frac{\mathit{DSCR\ (1.3)} \times \mathit{(CAPEX + Total\ Lifetime\ Interest)} + \mathit{Total\ Operating\ Costs}}{\mathit{Total\ Fuel\ Production}} = \text{Strike Price} \qquad \text{(eq. 3)}$$

The CAPEX and variable expenses are proportional to the size of the farm and the methane yield estimated through Equation 1. The CAPEX includes the materials and installation of a plug-flow digester for handling the dairy waste as well as the materials and installation for an on-site biogas-to-CNG conversion and conditioning unit. The CAPEX increases in proportion to the size of the dairy farm and number of cattle on-site, although it is nonlinear because there are economies of scale as the size of the farm increases. Once the equipment is installed, ongoing expenses include operation and maintenance costs, although there is no additional feedstock input. CAPEX data are derived from the AgSTAR model and the EPA Landfill Gas Cost model (EPA 2011, 2017). The Appendix provides further detail on our cost estimates for this analysis.

An important consideration in the dairy biogas assessment is the cost of transportation associated with bringing diary biogas-derived CNG to market. Dairy farms can be located far from urban centers and natural gas pipelines; therefore, the cost of pipeline interconnections can be prohibitively expensive, particularly for smaller-scale producers. However, trucking natural gas to inject into the grid has been demonstrated to be cost-effective in Wisconsin, suggesting that a similar strategy may be viable in California (Verburg, 2017). Likewise, the example of the Kern Dairy Biogas cluster in California indicates that economies of scale may be achieved in cases where several co-located dairy farms can transmit their biogas to a central location for gas cleaning and conditioning through a hub and spoke model (Black & Buckenham, 2017). Due to data limitations on the cost of CNG transport by truck, we assume that long-distance natural gas transport costs would be indicative of dairy biogas transport costs. To estimate this cost, we subtracted the average Henry Hub spot price for natural gas in 2016 from the average California commercial price for natural gas (Energy Information Administration [EIA], 2017). This generated a value of $0.77 per GGE of CNG, which may understate the expense associated with bringing CNG to market.

The cash flow model assumes that a project will be in operation for 15 years, although it will produce CNG at half of its theoretical capacity during its first year. We do not assume a lengthy construction period, unlike the assumption for larger, commercial-scale cellulosic ethanol projects. For an overview of the high-level inputs into the model, see Table 1. A more detailed description of the financial variables and methodological assumptions of the model is available in the Appendix.

The cash flow model generates an estimate of the per-GGE price necessary to secure a favorable return on investment for a dairy biogas project. Figure 1 illustrates the strike price for dairy biogas-derived CNG fuel based on the farm size. The strike price supply curve is presented in contrast to the price of bio-CNG with and without incentives. CNG in California was sold at $2.47/GGE (EIA, 2017). However, after factoring in the value from RFS renewable identification numbers (RINs) and LCFS credit prices at recent values, bio-CNG's value is substantially higher—approximately $6.00/GGE.[1] Drawing upon Miller et al. (2013), we discount the financial incentives from the RFS and LCFS programs by 50% of their 2016 values to reflect policy uncertainty.

Table 1. Summary of high-level inputs in the cash flow model

Input	Value
Capital expenditures (CAPEX)	Approximately $2-$10 million, depending on dairy farm size
Anaerobic digester O&M cost	$0.03/ft^3 biogas
Biogas conditioning & compression O&M cost	$1.05/GGE
Transport cost	$0.77/GGE
Interest rate on debt	8%
Debt service coverage ratio (DSCR)	1.3
Startup time	1 year
Project lifetime	15 years

Note: All monetary values are in 2017 U.S. dollars.

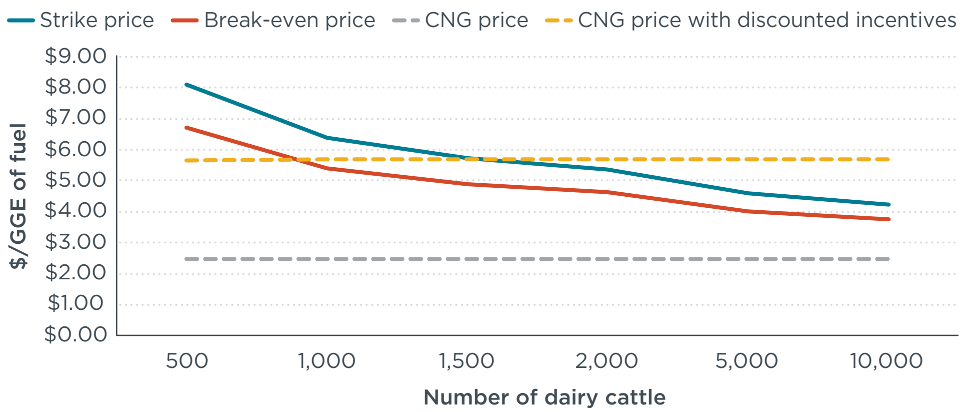

Figure 1. Project strike price in cash flow model versus dairy farm size

The outputs from the cash flow model indicate that the viable prices for the projects in the model range from approximately $4.00 to $8.00 per GGE of dairy biogas-derived CNG, with costs decreasing as the size of the farm increases. Unlike with cellulosic ethanol, the cost of producing bio-CNG is fairly close to the discounted incentives (Pavlenko et al., 2016); therefore, as long as the policies are in place at similar values, additional funding support from the CfD policy would be unnecessary and would serve only as a backstop in case of policy or market disruption. We use the strike price of $6.00 generated for a farm with around 1,250 cattle.

In our cost analysis, the market value of dairy biogas is strongly dependent on the LCFS credit price. For the purposes of estimating the LCFS credit price of dairy biogas, we assume a life-cycle carbon intensity of -273gCO_2e/MJ based on the dairy biogas CNG pathway from Kern County Dairy Biogas certified by the California ARB. This value is the lowest-carbon pathway certified within the LCFS, the result of a strong avoided methane effect per CARB's livestock offset protocol. It is likely that subsequent biogas projects would generate similar methane reductions; however, this is a source of uncertainty. Uncertainty associated with a given project's carbon intensity value within the LCFS prior to certification could be another contributor to investment risk and the discounting of the future value of LCFS credits. To

1 Here we use the life-cycle carbon intensity of -273 gCO2e/MJ for dairy biogas-derived CNG from the Kern County Dairy Biogas Cluster, which has been approved under California's LCFS.

examine the effect that carbon intensity score can have on the financial viability of dairy biogas projects and a CfD program, we conduct a sensitivity analysis assuming carbon intensity scores as high as 0 gCO_2e/MJ.

CFD COST-BENEFIT

To assess the impact of CfDs on the deployment of dairy biogas to CNG projects, we use the methodology developed in Pavlenko et al. (2016) using the strike price estimated through a cost analysis of dairy biogas CNG production above. We assume that the CfD policy would have $4 million of annual, nonguaranteed funding through 2030 and that auctions would be triggered every two years as long as there was sufficient funding to guarantee the liability for additional projects. Pavlenko et al. (2016) assumes potential CfD program funding of $40 million per year. Because dairy biogas production is much smaller in scale than cellulosic ethanol production—generally by an order of magnitude, if not more—a biogas CfD program could be effective at supporting multiple projects for only $4 million per year. Different funding levels would, of course, affect the number of projects and volumes of bio-CNG that could be supported by the program. As in Pavlenko et al. (2016), we assume CfD auctions are held every two years, from 2018 through 2030.

Each auction modeled is assumed to support two, average-sized dairy farms with a herd size of 1,250 cattle and a maximum production capacity of approximately 100,000 GGE of bio-CNG annually. The CfD contract provides 10 years of support that pays the difference whenever the market value for bio-CNG drops below $6.00 per GGE.

As in Pavlenko et al. (2016), we assume a per-gallon spending cap for the CfD program to limit the total liability of the program. Here, we assume that cap to be $2.00 per GGE, limiting the maximum liability for each additional project to an estimated $2.00 per GGE multiplied by the lifetime production of the project.[2] If the potential liability exceeds the accrued program funding minus existing liabilities in a scheduled auction year, the auction does not take place. Therefore, the first auction can support the maximum liability for two, 1,250-head dairy farms each producing approximately 100,000 GGE of bio-CNG. That could lead to approximately $3.7 million in lifetime payments in a worst-case scenario where the spending cap applies each year over the 10-year contract period.

Depending on a variety of policy and market factors, the market value of finished ultralow-carbon fuel could meet, fall below, or even exceed the strike price established through the reverse auction. For example, in an optimistic scenario, the sum of the LCFS credit value and D3 RIN greatly exceeds the strike price and generates a surplus of value.[3] In contrast, in a pessimistic policy mix, low credit prices in conjunction with a termination of RFS support necessitates payouts from the CfD program to maintain the strike price for the producers. It should be noted that the RFS program is expected to continue beyond 2022, but starting in 2022 major implementation changes are possible. It is also possible the RFS program could be repealed entirely at any point.

2 This analysis assumes a fairly large spending cap to reflect policy uncertainty due to the necessity of high LCFS credit prices to support dairy biogas; this large spending cap creates sizable risk-aversion in the policy's auction triggers.

3 D3 is the specific RIN code for cellulosic biofuel. Source: https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard

Our projected market value of dairy biogas CNG in each of these three scenarios is illustrated in Figure 2. In Pavlenko et al. (2016), there is a discussion of different avenues in the case that the market value exceeds the strike price: Biofuel producers could retain 100% of the additional profit, producers could be required to pay the difference back into the CfD program, or producers could be required to pay a portion of the additional profit back to the program and retain the remainder. For this analysis, we conservatively assumed that in such cases, the profit is entirely retained by biogas producers.

The policy scenarios make the following assumptions about policy context and credit values:

Baseline policy mix scenario: RFS and LCFS continue through 2030. Fossil fuel prices stay steady.

Optimistic policy mix scenario: RFS and LCFS continue through 2030. High fossil fuel prices.

Pessimistic policy mix scenario: LCFS continues through 2030. RFS ends after 2022. LCFS and RIN prices decline by 50% relative to 2016 levels over the entire 2018–2030 period. Low fossil fuel prices.

Table 2 illustrates the relationship between the auction structure in our assessment and the policy mixes assessed. In the baseline and optimistic policy mixes, the strike price is lower than the market value achieved from the combination of fuel sales, RINs, and LCFS credits; therefore, the program makes no payments and accrues funding over time. This allows the program to ramp up and increase the size of subsequent auctions, totaling 37 average-sized farms supported from all auctions held over the period 2018–2028. In the pessimistic scenario, the auctions are triggered provided that the per-GGE spending is below our assumed $2.00/GGE spending cap. In the pessimistic policy mix, the RFS program ends after 2022, and as a result, the per-GGE spending is too high to support new projects. Instead, the program funding goes toward supporting contracts begun before 2023. An alternative option that we did not include in our analysis would be for program administrators to increase the spending cap in order to facilitate further auctions for a smaller number of projects per auction compared to the number that could be accommodated while maintaining a $2.00/GGE spending cap.

To assess the cost-effectiveness of this incentive structure, we modeled the growth in CfD-financed fuel production from 2018 through 2030, accounting for potential growth in bio-CNG production from follow-up auctions if there was sufficient funding. After determining the volume of supported fuel production in each year, we subtracted the strike price from the market price for each project on an annual basis to determine the total spending. In both the baseline and optimistic policy mixes, the market value exceeded the strike price in every year so the CfD program did not pay out to producers. In the pessimistic policy mix, the CfD program paid out to producers annually based on need. The CfD costs were then normalized for each policy mix by dividing the total sum paid out by the total volume of fuel production supported.

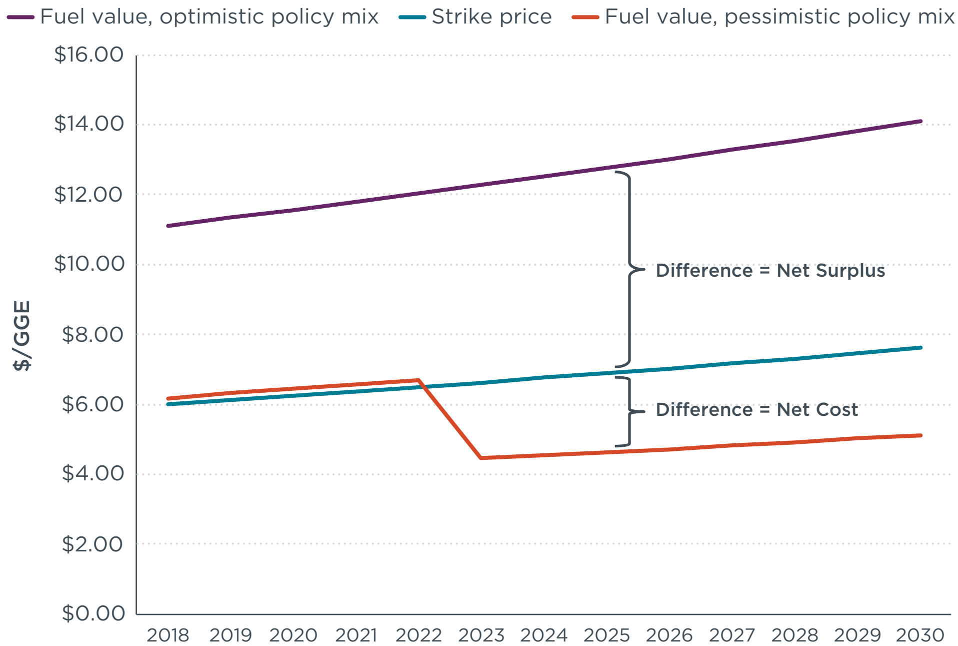

Figure 2. Impact of policy mix on CfD program cost.

Results

Our analysis finds that in a baseline policy mix, wherein the LCFS and RFS programs retain steady credit values through 2030, the CfD program would largely accrue funding over time instead of spending it on project support. Due to the value of these existing incentives, the market value of the finished fuel would exceed the strike price of $6.00/GGE. In this policy mix, the CfD program would accrue funding over time without making payments.

We find that in the first year of funding, the CfD program would be able to support two average-sized dairy biogas projects totaling approximately 200,000 GGE of bio-CNG production annually. The number of projects that could be supported by each subsequent auction would increase as the

Table 2. Project strike price and production capacity for each CfD auction assuming annual funding of $4 million

Auction Number (Year)	Strike Price (per GGE)	New Production Capacity (Million GGE per Year)	Number of new Farms Supported (1,250 cattle per Farm)	New Production Capacity (Million GGE per Year)	Number of new Farms Supported (1,250 cattle per Farm)
		Baseline and optimistic policy mix		Pessimistic policy mix	
1 (2018)	$6.00	0.2	2	0.2	2
2 (2020)	$6.00	0.2	2	0.2	2
3 (2022)	$6.00	0.6	6	0.6	6
4 (2024)	$6.00	0.7	7	No auction	0
5 (2026)	$6.00	0.9	9	No auction	0
6 (2028)	$6.00	1.1	11	No auction	0

Note: Each estimated strike price is rounded to the nearest $0.25.

program continued to amass funding. The cumulative production capacity supported through CfD's would grow from 0.1 million GGE per year at the program's outset to a total production capacity of approximately 3.6 million GGE within 10 years, supporting a total of 37 projects over this time.[4] The results of the optimistic policy scenario, in which fossil natural gas prices rise, are the same as the baseline policy scenario because in both scenarios, the CfD program makes no payments. In an optimistic scenario, additional benefits would accrue to biogas project owners in the form of higher profits.

In the pessimistic policy mix scenario, in which RFS and LCFS credit prices fall and the RFS program ends in 2022, the CfD program would pay out an average of $1.62/GGE. Even in this scenario, the CfD program would be able to support substantial volumes of dairy biogas. Over the period 2018–2030, the program could support 10 projects and a cumulative production capacity that ramps up to approximately 1 million GGE by 2028.

Table 3 summarizes the results across the three policy scenarios for bio-CNG support. As shown in the table, for the baseline and optimistic cases, the cost is zero based on the fact that the values of other, non-CfD policies exceed the strike price. In these two scenarios, the total new production supports more than 19 million GGE. In the more pessimistic case, the cost of support increases in response to lower LCFS prices and the end of the RFS support after 2022; in this scenario, the cost rises to an average $1.62/GGE from 2018–2030. Even in this scenario, the policy is able to support more than 8 million GGE of new production at a cost of $32.00 per tonne of CO_2e abated.

Table 3. CfD cost assessment for bio-CNG assuming annual funding of $4 million

Policy Scenario	Cost (per GGE)	Total New Production Supported, 2018-2030 (Million GGE)	Cost of GHG Reduction ($ per tonne CO_2e)
Baseline & optimistic	$0.00	19.46	0
Pessimistic	$1.62	8.55	$32

Note: CO_2e = carbon dioxide equivalents; GHG = greenhouse gas; GGE = gasoline-gallon equivalent.

Compared to our previous assessment of CfDs for supporting cellulosic ethanol, we find that using CfDs to support CNG from dairy biogas generates more cost-effective GHG reductions, although a small program with annual revenue of $4 million would support modest volumes compared to the larger $40 million cellulosic biofuel program we assessed in Pavlenko et al. (2017). Whereas the pessimistic policy scenario results in a GHG reduction cost of $32/tonne CO_2e for bio-CNG here, our assessment of CfDs for cellulosic ethanol estimated a higher price of $148/tonne. Pavlenko et al. (2017) estimates that CfDs could support more than 100 million GGE of cellulosic ethanol in California by 2030 even after accounting for construction and startup time, compared to the 8.55 to 19.46 million GGE of dairy biogas that we estimate could be supported in this analysis.

The lower cost-benefit ratio of dairy biogas is largely the result of its much lower carbon intensity than even the best-performing cellulosic ethanol; this difference primarily comes from crediting avoided methane emissions. ARB has assessed two dairy biogas projects in California as having carbon intensities of -273 and -254 gCO_2e/MJ, and we would expect other dairy biogas projects to receive similar ratings. However, because the carbon intensity score is a source of uncertainty for new potential projects, we conducted a sensitivity analysis. The carbon intensity score directly affects project cost as well as the calculation of GHG benefits because LCFS credits are awarded on the basis of life-cycle GHG reductions. A lower carbon intensity score by ARB would result in more LCFS credits and thus award greater policy value to a given volume of biogas. The RFS program does not differentiate RIN support among dairy biogas projects based on carbon intensity.

We performed a sensitivity analysis using an assumed bio-CNG carbon intensity of 0 gCO2e/MJ, which we consider to be a worst-case scenario for dairy biogas. Even for biogas with this carbon intensity, existing incentives could still support high market values. We estimate that the CfD program would still support 37 projects and cumulative production capacity of approximately 3.6 million gallons after 10 years of the program in the baseline and optimistic policy mixes. The number of projects would drop to nine and the cumulative supported production capacity would be 0.9 million gallons in the pessimistic policy mix with a carbon intensity score of 0 gCO2e/MJ. The cost-benefit ratio would remain $0/tonne CO_2e in the baseline and optimistic scenarios, but would increase to $120/tonne CO_2e in the pessimistic scenario.

Additionally, the cost constraint we use in our assumptions limits the expansion of CNG conversion facilities; by limiting program funding to $4 million annually versus $40 million in the previous study, we are accounting

4 We assume that each project has a "start-up" time of 1 year at which it operates at half of its production capacity

for the relative small scale of individual dairy biogas producers as well as the limited amount of dairy biogas potential overall. In contrast, cellulosic ethanol could theoretically produce greater volumes of fuel, especially in the longer term, because of greater overall potential feedstock availability (Black, 2016; U.S. Department of Energy, 2016).

Another area of uncertainty with respect to bio-CNG viability that emerged from this analysis is the distribution phase of production, as dairy projects may be far from CNG markets. This factor could greatly affect the cost of production of the finished fuel. While there is evidence that trucking CNG to pipeline injection sites can be viable (Verburg, 2017), the distance and difficulty of bringing bio-CNG to commercial vehicle markets could theoretically involve longer distances and thus higher costs.

Conclusion

This study assesses the effectiveness of a CfD program to support projects producing transportation fuel from dairy biogas. Our analysis finds that a new project collecting biogas at an average-sized dairy farm in California and delivering it to market would be cost viable under current market conditions if the full value of existing biofuel incentives is realized. At present, policy and market uncertainty undermine the business case for investing in new dairy biogas projects, and a CfD program could be effective at mitigating that risk.

We find that a CfD program with a modest amount of funding could support a substantial number of dairy biogas projects and production volumes over the period 2018–2030. In a baseline or optimistic scenario, the program would not pay out any funds because other existing incentives would be sufficient to ensure new projects are profitable. Even in a pessimistic policy scenario, a CfD program would be able to provide enough additional financial support to a significant number of projects. In our analysis, we assumed that annual funding for a CfD program would not be guaranteed, and that the program's commitments each year would be limited to the total liability it could take on over the 10-year contract period. However, if annual funding were guaranteed over 10 or more years, a CfD program could support a much greater number of projects initially. Our analysis also finds that a CfD program supporting dairy biogas would be a highly cost-effective method for climate mitigation, reducing GHG emissions at a cost of \$0–\$32/tonne CO_2e.

This analysis reinforces the findings from Pavlenko et al. (2017) that CfDs are a cost-effective form of policy support because they leverage the funding of other, existing incentives and minimize payouts. Instead of a primary funding source for advanced fuels, a CfD program acts more as an insurance policy against political and economic uncertainty. The pay-as-needed policy design ensures that the CfD program would support only the projects developed in conjunction with the program's support based on their demonstrated level of need. In cases where a project is unable to generate any volume of fuel, the government would not make any payments to the producers.

Within the context of California Senate Bill 1383 from 2016, establishing a CfD financing scheme for dairy biogas projects to produce transportation fuels would provide a cost-effective method of reducing methane emissions and meeting the law's emissions targets. Furthermore, piloting this financing scheme could provide a proof-of-concept to support other fuel sources with greater potential market share, such as cellulose-derived fuels, over the longer term, helping to meet the stricter 2030 Low Carbon Fuel Standard targets. Outside of California, the CfD method could become a valuable tool to bridge the commercialization gap for advanced fuels with similar policy and market dynamics, enabling jurisdictions like the EU to meet their ambitious climate goals.

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Appendix — Modeling Assumptions

This section summarizes the key inputs and assumptions used to develop this study's assessment of biogas yield, dairy biogas operating costs, and the cash flow model. For each input, this section provides a brief overview of how it is defined and how it fits into the analysis, along with the documented source for that input.

Table A1. Summary of high-level inputs in the cash flow model

Input	Value	Description	Source
Anaerobic digester CAPEX	\$645,813 + \$704 per head of cattle	Estimated capital costs to construct a plug-flow digester. Costs are derived from an AgSTAR model regression.	Lazarus (2015)
Anaerobic digester operation & maintenance cost	\$0.03/ft^3 biogas	Estimated operation and maintenance cost; derived from a value of \$0.02/kWh for anaerobic digester maintenance. This assumes a methane content of 50% in biogas, an electricity generator efficiency of 35% and an equipment capacity factor of 90%.	Lazarus (2015)
Onsite CNG production & fueling station CAPEX	\$95,000 per ft^3/min of biogas flow	Estimated capital cost to construct an LFG-to-CNG conversion and conditioning unit; includes equipment cost, engineering and installation.	EPA (2017)
Onsite CNG production operation & maintenance cost	\$1.05/GGE	Ongoing costs incurred for media, equipment operation, and parasitic load from running the CNG production and fueling station.	EPA (2017)
CNG yield	0.003 GGE/ft^3 biogas	CNG yield is based on the energy content of methane, an assumed methane content of 50%, a capacity factor of 93% and a conversion efficiency of 65%.	EPA (2017)
CNG production capacity factor	93%	This is an assumption of the actual output of the CNG production over time relative to its total potential output if it were able to operate continuously.	EPA (2017)
Biogas methane content	50%	Proportion of methane (CH_4) in dairy biogas.	EPA (2017)
Typical animal mass	1,332 lbs	Average mass of a dairy cow.	EPA (2011)
VS excretion rate	10.1 lbs VS/1,000 lbs of animal mass	This is the rate of volatile solids (VS) excreted per animal.	EPA (2011)
Methane B_o	3.84 ft^3 CH_4/lb VS	This is the methane generation rate per unit of VS in an anaerobic digester.	EPA (2011)
Methane conversion factor, MCF	0.741	This is an estimate of the methane producing potential achieved for an anaerobic digester manure management system in California.	EPA (2011)
CNG price, West Coast	\$2.44/GGE	Average retail price for CNG for vehicle use on the West Coast.	Alternative Fuels Data Center (2017)
Natural gas distribution cost	\$5.95/MCF CNG	Distribution cost is based on the difference between the average 2016 Henry Hub natural gas spot price and the average 2016 natural gas commercial price in California.	EIA (2017)
Startup time	1 year	This analysis uses an assumption wherein each project engages in a ramping up of production from the end of construction through to reaching full capacity. This assumption of 50% production capacity was informed by observed startup phases for commercial-scale projects in the United States that did not reach full production immediately.	Authors' assumption
Operational lifetime	15 years	This is the estimated production period for each the projects in question. We assume that the principle is paid down for the entire period through annual payments.	Authors' assumption
Interest rate on debt	8%	Annual interest paid for upfront capital expenses financed through debt	Bole et al. (2010)
Debt versus equity split	100/0	We assume that due to the relatively small size of the loans necessary for dairy biogas equipment, this expense is financed solely through debt.	Authors' assumption
Inflation rate	1.2%	Annual U.S. inflation rate, based on last 5 years of annual inflation	Authors' assumption