Dairy Biogas in California:
Cost-Effective Development

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Biogas is a renewable fuel with several co-benefits, yet it has seen relatively little development in the state of California. This is due to both the costs of biogas technology and barriers to widespread deployment. This paper examines the potential, barriers to and financial drivers of biogas and offers some solutions for promoting the development of the industry in California. Financial and policy barriers to development include low natural gas prices, high capital costs, scale issues, and environmental permits. The paper finds that project revenues are more sensitive to carbon offset prices than electricity prices, under feasible price ranges. Offset prices that provide adequate return on investment (ROI) for project developers are between \$12 and \$24 per metric ton of carbon dioxide equivalent (MT CO_2e).

The paper makes several recommendations to promote in-state, cost-effective biogas development. Namely, policymakers and project developers should promote a robust carbon offset market, develop co-digestion where feasible, consider carbon offset revenues in setting electricity prices for Renewables Portfolio Standard (RPS) procurement, and continue and expand information exchange. These actions will allow biogas to be developed cost-effectively while protecting ratepayers.

OVERVIEW: BIOGAS POTENTIAL AND CURRENT CAPACITY

Biogas is a form of renewable energy with many attractive attributes: it provides flexible, dispatchable electricity generation, prevents methane release into the atmosphere, and can be used as a fuel in many parts of the existing energy infrastructure. Despite its robust potential in California, biogas has not grown at the same rate as other renewable energy technologies like wind and solar. This is due to both the costs of biogas technology and barriers to widespread deployment.

What Is Biogas?

Biogas is produced by the anaerobic digestion or fermentation of biodegradable materials such as biomass, manure, sewage, municipal waste, green waste, plant material, and crops. Biogas is primarily methane (CH_4) and carbon dioxide (CO_2), and may also contain small amounts of carbon monoxide (CO), hydrogen sulfide (H_2S) and moisture (H_2O). As a flexible renewable fuel, biogas can be used for any application in which natural gas is used: biogas can generate electricity, be compressed and used as motor vehicle fuel, or upgraded to a pipeline quality biomethane, a natural gas substitute.

This article discusses biogas derived from the anaerobic digestion of dairy manure and the use of that biogas as biomethane or to produce electricity in California. It does not discuss captured gas from landfills, also known as landfill gas (LFG), or biogas from wastewater treatment plants (WWTPs).

History of Biogas in California[1]

Due to the large number of dairy farms in California, there is great potential for biogas development. According to the EPA's AgSTAR program, California has the potential to produce up to 2,375,000 megawatt-hours (MWh) per year from biogas from 889 candidate dairy farms located throughout the state.[2,3] This is roughly 1 percent of total state electricity demand.

The rate of biogas development in California has varied widely over the past ten years, driven primarily by government support for technology development, the availability of subsidies, and state regulations. Prior to 2002, fewer than five dairies in California operated anaerobic digesters. Each of these dairies used the biogas produced by the digester to fuel a generator for onsite electricity use. The California Energy Commission (CEC) has provided grant funding of up to 50 percent of capital costs to support the construction of additional digesters at dairies. However, proponents of dairy digesters have found new air and water quality regulations difficult to understand and comply with, and several CEC-funded digesters ceased operation as a result of regulatory and financial problems.[4] As of May 2011, there were fifteen operational digesters in CA, and none currently under construction (for a map of some of these locations, see Figure 1).[5]

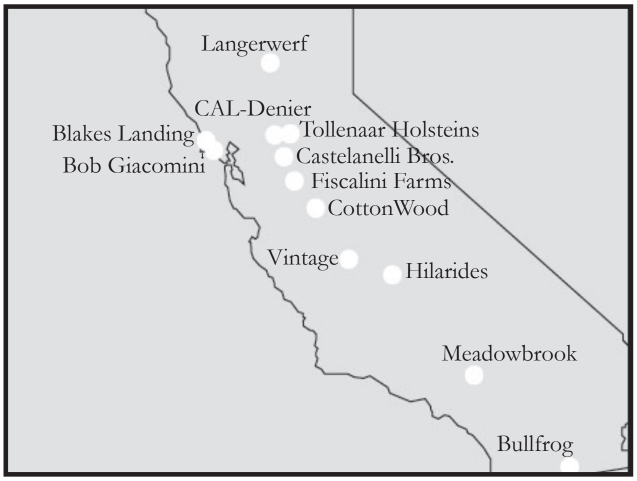


Figure 1: Locations of Dairy Biogas Digesters in California (Source: California Biomass Collaborative[6])

BIOGAS POLICY IN CALIFORNIA

Biogas and biomethane production impacts air quality, water quality, greenhouse gas (GHG) emissions, electricity procurement, renewable energy production, and natural gas distribution. While biogas can have positive effects on many of these issues, fragmented permitting and regulatory processes can prevent or delay project development.

CEC Suspension

On March 28, 2012, the CEC voted to suspend certification of pipeline biomethane projects as an eligible renewable technology under California's RPS due to concerns over possible double counting of the renewable energy attributes of biogas.[7] Recent legislation has clarified the RPS-eligibility of biomethane fueled facilities, and a March 2013 CEC draft guidance re-instated biomethane as an eligible renewable technology.[8,9] Nonetheless, the suspension created a considerable amount of regulatory uncertainty for biogas developers.[10]

RPS Procurement Programs

Biogas is also eligible for California's Feed-in Tariff (FiT), which was developed to offer standard contracts to small renewable projects.[11] The Commission has established two utility-scale distributed generation programs through which biogas projects can sell their electricity to the State's investor-owned utilities (IOUs): the Renewable Auction Mechanism (RAM) and the Renewable Market Adjustment Tariff (Re-MAT). Both of these programs are designed to procure energy at least cost, but account for the availability of different renewables (such as peaking as available, non-peaking as available, and baseload).[12] As prices are influenced by submitted project bids, the contract price that baseload generation (including biogas) will obtain is unclear.

On September 27, 2012, Governor Brown signed into law Senate Bill (SB) 1122, which created an additional 250 MW goal for small bioenergy projects under California's RPS. SB 1222 directs the Commission to develop separate standardized contracts for these bioenergy facilities, including 90 MW of dairy bioenergy capacity.[13]

Net Metering & Net Surplus Compensation

Several biogas sites in California with on-site electricity generation produce electricity through the Net Energy Metering (NEM) program. The NEM program was originally developed for owners of residential solar photovoltaic systems and did not compensate participants for any excess electricity generated. As on-site dairy digesters typically produce electricity in excess of on-site consumption, this led to significant loss in revenues and prompted facility owners to flare excess biogas supply. Since 2010, AB 920 has required California utilities to compensate biogas generators for excess generation through a Net Surplus Compensation (NSC) rate structure. While the prices paid under NSC are generally lower than prices paid under NEM, NSC has aided economic feasibility and minimized unnecessary flaring.[14]

AB32: California Global Warming Solutions Act

In November 2012, California conducted its first auction for its cap-and-trade program, implemented in response to AB 32, the California Global Warming Solutions Act.[15] The law creates incentives to reduce greenhouse gas emissions through a declining allocation of allowances. Current prices for allowances are approximately \$14/MT CO_2e.[16] At present, California plans to join the Canadian province of Quebec for a multi-region cap-and-trade program as part of the Western Climate Initiative (WCI).

Currently, livestock projects (including methane capture and destruction from manure management systems) are one of four compliance offset protocols adopted by the California Air Resources Board (CARB).[17] In March 2013, CARB listed twenty-five carbon offset projects from other project registries, including thirteen projects that destroy agricultural methane, that could produce compliance-grade offsets should they be verified by an accredited third-party verifier. Voluntary credits are currently valued at around \$8, but will likely rise to \$10 should they be converted to compliance grade.[18]

We discuss several other aspects of California's cap-and-trade program in our recommendations.

BARRIERS: PROJECT COSTS AND FINANCING FOR BIOGAS

California's biogas industry faces several barriers to growth. These include high costs, regulatory issues, and financing hurdles. Understanding each of these barriers is essential to unlocking cost-effective biogas development. The information presented below has been compiled from several reports and conversations with several biogas developers.

Existing Facility Costs

Biogas continues to be one of the more expensive renewable technologies in California. As Table 1 shows, the CEC's analysis of existing dairy digester projects found that the nominal levelized cost of energy (LCOE) for a biogas facility without subsidies ranged from $0.1016/kilowatt-hour (kWh) to $0.3716/kWh.[19,20] While the low end of that range is competitive with existing prices for other renewable technologies in California, it reflects a digester made from refurbished parts purchased at a significant discount, and is not indicative of LCOE for new digesters. These prices do not include environmental quality enhancements, including improved liners for lagoon storage systems. Given CARB and California Regional Water Quality Control Board, Central Valley Region (CRWQCB-CVR) regulations, we would expect these systems to have somewhat higher costs if they were built today, all else being equal. Similarly, an analysis by ESA Associates, sponsored by the CRWQCB-CVR, found that none of their hypothetical digester systems had annual revenues high enough to ensure sufficient profitability. To ensure profitability, ESA's report notes that a revenue increase of 32 percent to 53 percent is required, corresponding to a productivity increase of between 128 percent and 392 percent.[22] We will be drawing upon ESA's report assumptions for the economic analysis presented later in this paper.

Major Cost Contributors

Biogas development faces many barriers in California that have hindered the widespread deployment of the technology. Of these, cost is the most direct factor affecting feasibility. Simply put, high technology costs, spurred by scale limitations, environmental regulations, and the nature of biogas production, limit biogas's economic feasibility.[23]

Low Natural Gas Prices

Biogas (including biomethane) and natural gas are nearly homogeneous commodities. However, price disparities between the two are one of the highest barriers for biogas development. Current prices for natural gas are below $4 per million British Thermal Units (MMBTU).[24] For pipeline-quality gas, the LCOE for biogas ranges from $12 to $48 per MMBTU.[25] This price disparity is due to recent shale gas discoveries in the United States as well as the continuing

Table 1: Digester Costs from Dairy Power Producer Program (DPPP) Participants
Nominal LCOE ranges from $0.10 to $0.37 /kWh (2007 dollars)[21]

Dairy Digester Type / Special notes	Capital Cost ($/kW)	Year 1 Wholesale ($/kWh)	Nominal LCOE (2007$) ($/kWh
Hilarides: Covered lagoon	2,643; 2005 $	0.0991; 2006 $	0.1016
Eden-Vale: Plug-flow	4,766; 2005 $	0.1720; 2006 $	0.1763
Koetsier: Plug-flow	5,611; 2005 $	0.1990; 2006 $	0.2040
Castelanelli: Covered lagoon	6,070; 2004 $	0.2160; 2005 $	0.2269
Van Ommering: Plug-flow	7,109; 2005 $	0.2550; 2006 $	0.2614
Meadowbrook: Plug-flow	6,466; 2004 $	0.2630; 2005 $	0.2763
IEUA: Modified mix plug-flow	14,547; 2005 $	0.3350; 2006 $	0.3434
Cottonwood: Covered lagoon	8,180; 2004 $	0.3375; 2005 $	0.3546
Blakes Landing: Covered lagoon	4,801; 2004 $	0.3540; 2005 $	0.3719

economic weakness. While natural gas prices are expected to rise in the medium-term, biogas faces daunting cost reduction needs without support from subsidies.

Interconnection

Although local electric utilities are potential customers for excess electricity production from on-site generation systems, connecting to the grid represents a cost barrier for some biogas projects. Due to large fixed costs, interconnection exhibits economies of scale. As the size of a dairy digester project increases, it is able to spread the costs of interconnection over more energy generation, leading to per-unit cost savings. Yet, because the output of biogas on dairy farms is dependent upon the number of cows, small dairies are unable to take advantage of these economies of scale. Streamlined interconnection procedures could improve the cost-effectiveness of these projects.

Upgrading to Pipeline-Quality Standards

The digester project may inject biogas directly into existing natural gas distribution systems, but first it must upgrade the biogas to achieve pipeline-quality standards.[26] This process also faces significant economies of scale, and while centralized upgrading facilities can mitigate this barrier, transport costs represent a significant diseconomy of scale. System design and location considerations are important to cost-effective upgrading. The proximity of a biogas location to both feedstocks and energy infrastructure has a large influence on overall system cost.

Digester Costs

While digester costs are a large part of the overall system costs, there is little opportunity for cost reduction from this "relatively simple and mature technology."[27] Technological improvements and resulting cost reductions are incremental, and there are more significant cost reductions possible for on-site electricity generation and biomethane upgrading technology. These include low emission internal combustion engines, microturbines, and fuel cells.

Environmental Impact Mitigation

State and local environmental and quality regulations affect biogas in several ways. Biogas developers undergo scrutiny from several different local and statewide agencies, each with different decision-making timelines.

Air-quality regulations, in particular, are a high hurdle to biogas development. In the Central Valley and South Coast, which are classified as extreme nonattainment areas for ozone, regulations set forth by the Clean Air Act appear to be particularly burdensome for biogas facilities.[28] On-site generation must meet Best Available Control Technology (BACT) standards for nitrogen oxide (NOx) emissions, which require more costly controls than other technologies. As low emission electricity generation technologies are relatively immature, there may be cost-reduction potential in the future. The CEC, in concert with project developers, has been exploring the development of such technologies and there is an opportunity to use the Electricity Procurement Investment Charge (EPIC) to develop these technologies.

In addition to air and water impact mitigation, preventing water contamination from solid waste discharge can entail additional capital costs for biogas.

Financing

Finally, the financing available to biogas project developers constrains industry growth. Private funding for digester development has been scarce and costly. Biogas is typically financed by equity investment, which entails an investor's rate of return (IRR) often in excess of 15 percent. In contrast, debt financing, often from commercial lenders, entails an IRR often between 7 to 10 percent. Since the cost of capital for biogas is much higher, project developers are forced to charge higher prices for biogas products.

To date, debt financing has been unavailable for biogas because of risk. This is due to both cost and regulatory barriers. Reducing risk and stabilizing both costs and revenues are key objectives for future biogas development.

Economic Analysis

Deterministic Project Revenue Analysis

To understand the effect of prices on the feasibility of biogas projects, we undertook a financial analysis of four biogas technologies: a digester with on-site generation ("on-site digester," 1,000 cows, 100 kW), on-site digester with co-digestion (1,000 cows, 200 kW), biomethane for pipeline injection (10,000 cows), and a centralized biomethane facility (10,000 cows, nine facilities).[29] Our analysis was based on a 2011 analysis by ESA Associates, which was sponsored by the CRWQCB-CVR. For technical assumptions and base cost projections, please consult the ESA report.[30]

Methodology

ESA's analysis includes detailed estimates of costs and productivity for several different digester technologies. It also includes a cash-flow analysis that identifies profits and sufficient revenues to ensure adequate profitability.[31] The target IRR was set between Prime + 12 percent and Prime + 15 percent.[32]

Using ESA's results as a base case, we were able to probe the effect of carbon offset and electricity prices on yearly project revenues, which are largely driven by the sale of electricity and carbon offsets. We then compared these revenues with those ESA established as adequate to ensure profitability. In the results presented below, a revenue surplus of $0 (or 0 percent) or more indicates adequate profitability for the digester project. All values are in 2010 dollars.

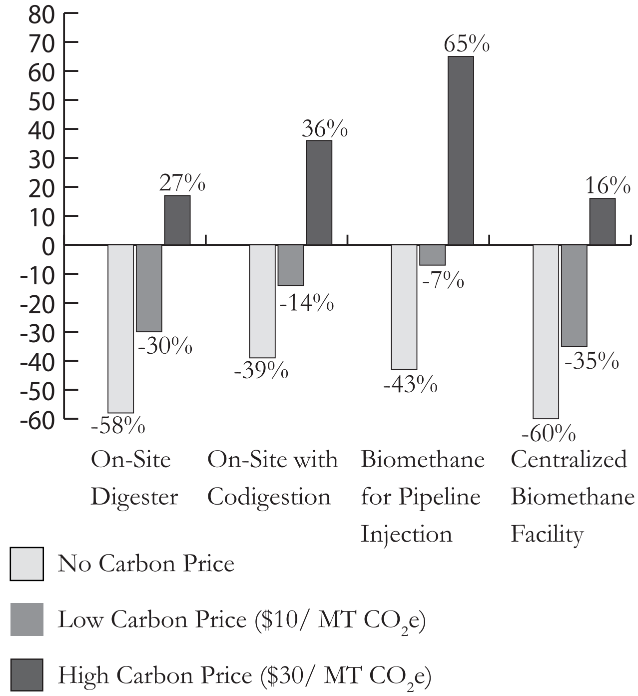
Assumptions for Carbon Offset and Electricity Prices. First, we looked at the revenues for three different carbon offset scenarios: No carbon price ($0/MT CO_2e), low carbon price ($10/MT CO_2e), and high carbon price ($30/MT CO_2e), with electricity prices fixed at the base case scenario. The low carbon price scenario assumes that offsets sell at the 2012 floor price for compliance permits (also known as allowances) under California's dap-and-trade program.[33] The high carbon price scenario, in contrast, assumes that allowance prices have reached the Allowance Price Containment Reserve price in the first year of California's cap-and-trade program[34] and that offsets are available at a discount of approximately 25 percent compared to allowances.[35] Offset prices are influenced by both supply and demand, and are subject to a wide range of uncertainty. Prices for offsets are also expected to increase over time as demand increases. This analysis ignores transaction costs, and assumes the full value of offsets sold is rewarded to the project developers.

Second, we examined revenues for three different electricity price scenarios: ESA's base case, a low compensation case, and high compensation case. All three scenarios are based on a net energy metering/net surplus compensation scenario.[36] In all cases, on-site generation was priced at $130/MWh. In the base case, excess generation was priced at $70/MWh. In the low compensation case, excess generation was priced at $40/MWh, which approximates the Default Load Aggregation Point (DLAP) price used for day-ahead forecasts without any additional environmental or renewable energy adders. Finally, in the high compensation case, all generation is priced at $130/MWh. This price has been identified in the recent Re-MAT decision as a price that might incent biogas generation and development.[37]

Results for Deterministic Analysis

Our results show that project revenues are highly sensitive to offset prices. Figure 2 shows the yearly revenue surplus or shortfall of four digester technologies at different carbon prices, presented as a percentage of required revenues for adequate profitability. In the no carbon price and low carbon price scenarios, no technologies achieve adequate profitability, though a centralized digester system falls only 7 percent below with offsets at $10/MT CO_2e. In the high carbon price scenario, all technologies are profitable, and approach a level that could be considered a windfall.

Figure 2: Yearly Revenue Surplus or Shortfall of Four Digester Technologies[38]



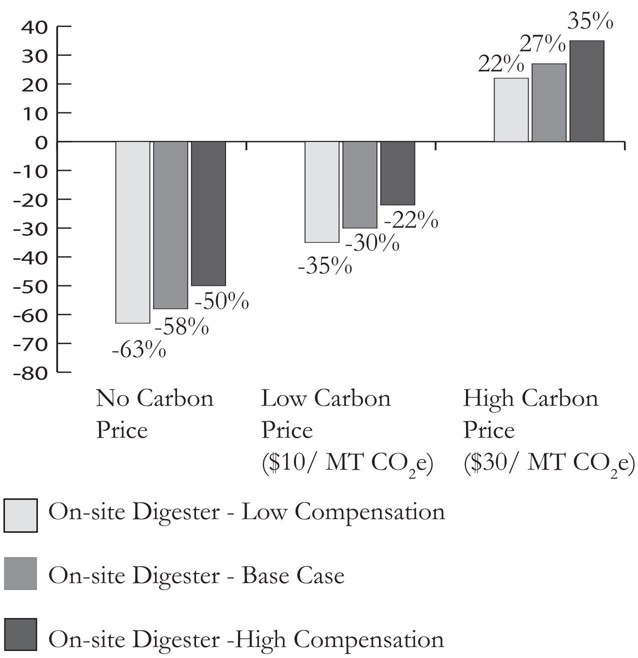
Next, we found the target offset price for each technology to achieve adequate revenues (that is, the price such that the difference between actual and required revenues was $0). Target prices ranged from $11.99 to $23.72/MT CO_2e, as shown in Table 2.

Table 2: Target Offset Prices
(Carbon offset price required for adequate revenues for four digester technologies)

Technology	Target Offset Price (2010$/MT CO_2e)
On-Site Digester (1,000 cows, 100 kW)	20.40
On-Site Digester with Co-Digestion (1,000 cows, 200 kW)	15.71
Biomethane for Pipeline Injection (10,000 cows)	11.99
Centralized Biomethane Facility (10,000 cows, 9 facilities)	23.72

Next we examined the impact of electricity prices on project revenues. We found that project revenues are less sensitive to electricity prices than carbon prices. As shown in Figure 3, revenues only vary by 13 percent between the low compensation scenario and high compensation scenario, while revenues vary by 85 percent between the no carbon price and the high carbon price scenarios. Values shown in Figure 3 are for on-site digester technology. From this analysis we found that carbon price affects revenues more than electricity price, a result that is consistent among all modeled technologies.

Figure 3: Yearly Surplus or Shortfall in Revenues for On-site Digester for All Carbon Offset Scenarios[39]



As project revenues are less sensitive to electricity price than carbon offset price, "target" electricity prices are generally outside the bounds of existing renewable prices in California. For example, the electricity price that would achieve adequate revenues for an on-site digester in the absence of a carbon offset price is $0.306/kWh or $306/MWh. Comparatively, the 2011 Market Price Referent (MPR) ranges from $76/MWh to $123/MWh for ten to twenty-five year contracts coming online between 2012 and 2020.[40]

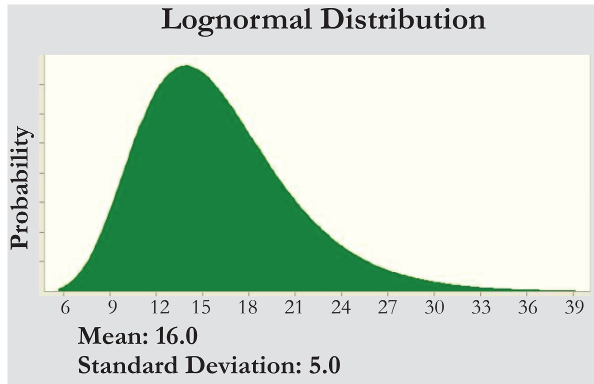
Probabilistic Project Revenue Analysis

Next, we expand our financial analysis of biogas technologies to simulate revenues with uncertain carbon offset and electricity prices.

Methodology

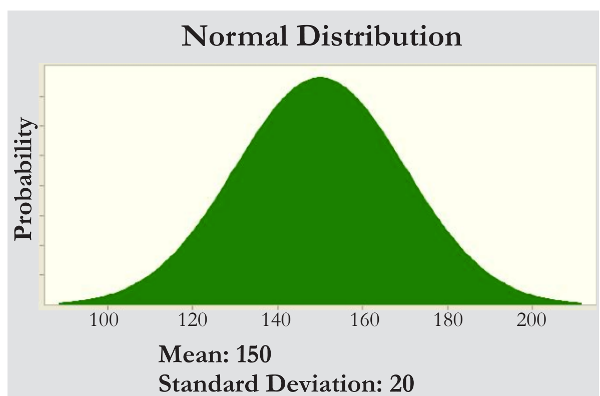
For each of the four technologies discussed above, we undertook a Monte Carlo analysis of revenues based on an assumed probability density function (PDF) for carbon offset prices. We chose a lognormal distribution with mean of $16/MT CO_2e, and standard deviation of $5/MT CO_2e. We believe the lognormal distribution represents well the non-negligible chance of very high carbon offset prices (in excess of $30/MT CO_2e) without assigning too high of a probability to this outcome. All analysis was performed using the Crystal Ball module in Microsoft Excel. The PDF for carbon offset prices is shown in Figure 4.

Figure 4: Assumed lognormal distribution for carbon offset price



Following this, we performed a Monte Carlo analysis of yearly revenues under both electricity price and carbon offset price uncertainty for the on-site digester technology. Here, the electricity price was set at a mean of $150/MWh, with a standard deviation of $20/MWh. While these prices are higher than that offered to most other electricity generation in California, it is a likely price given recent legislative action to create standard offer contracts for bioenergy generation in California as part of a "carve out" to the state's Renewable Portfolio Standard Program.[41] The CPUC and others are currently determining this administratively set electricity price. As such, project developers face uncertainty when planning future biogas projects.

Figure 5: Assumed normal distribution for electricity price under recent legislative changes



Results of Probabilistic Analysis

For on-site digester technology, we see that revenues vary widely based on carbon prices. Sufficient yearly revenues for adequate profitability are approximately $250,000 for an on-site digester, but mean revenues are $35,000 short of that benchmark (see Table 3 and Figure 6 for the results of the simulations).

Figure 6: Revenue surplus or shortfall, compared to required revenue, for on-site digester with carbon offset price uncertainty

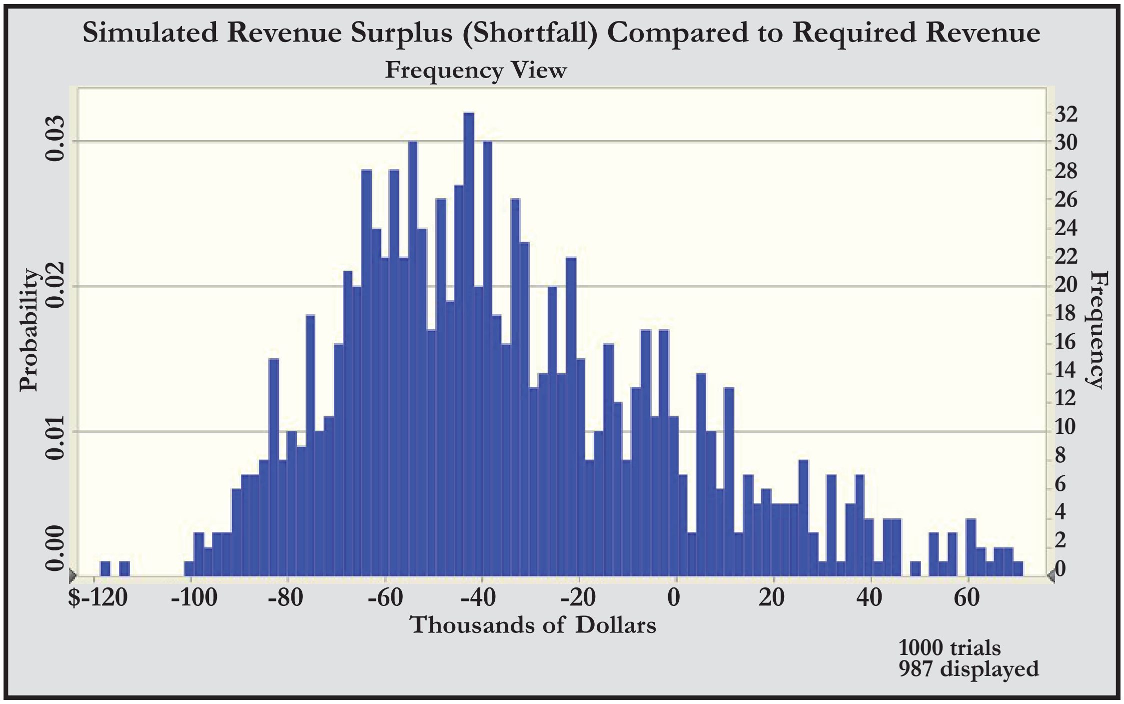


Table 3: Simulation Results for Uncertain Offset Price
($, Rounded to nearest thousand)

Mean (Deviation from Required Revenues)	-35,000
Standard Deviation	37,000 (~15% of target)
Maximum	112,000
Minimum	-119,000

Table 4: Simulation Results for Uncertain Offset and Electricity Price
(Rounded to nearest thousand)

Mean (Deviation from Required Revenues)	4,000
Standard Deviation	40,000
Maximum	164,000
Minimum	-91,000

This result further confirms the dependence of project revenues on carbon offset prices, and suggests policies that create price stability for project developers are important going forward.

When facing both electricity and carbon offset price uncertainty, we see two main results: First, the mean revenue surplus increases, as contracted electricity prices have been increased. Second, the standard deviation increases, but by less than 10 percent of its previous value. The small magnitude of the effect of this change is likely for two reasons. First, the PDF of electricity prices has smaller standard deviation (is "tighter") than the PDF of offset prices. Second, as the effect of electricity prices is smaller than offset prices, introducing randomness into the sampled value has a correspondingly smaller effect.

In conclusion, both our deterministic and probabilistic analyses confirm that project revenues for biogas projects are very dependent on carbon offset prices. Moving forward, policies that promote price stability, including long-term contracts and futures markets, will help the biogas industry to grow and stabilize.

RECOMMENDATIONS

There are several opportunities to encourage the cost-effective development of biogas in California. Several actors, from CARB and the CPUC to project developers themselves, can make biogas cost-effective while protecting ratepayers.

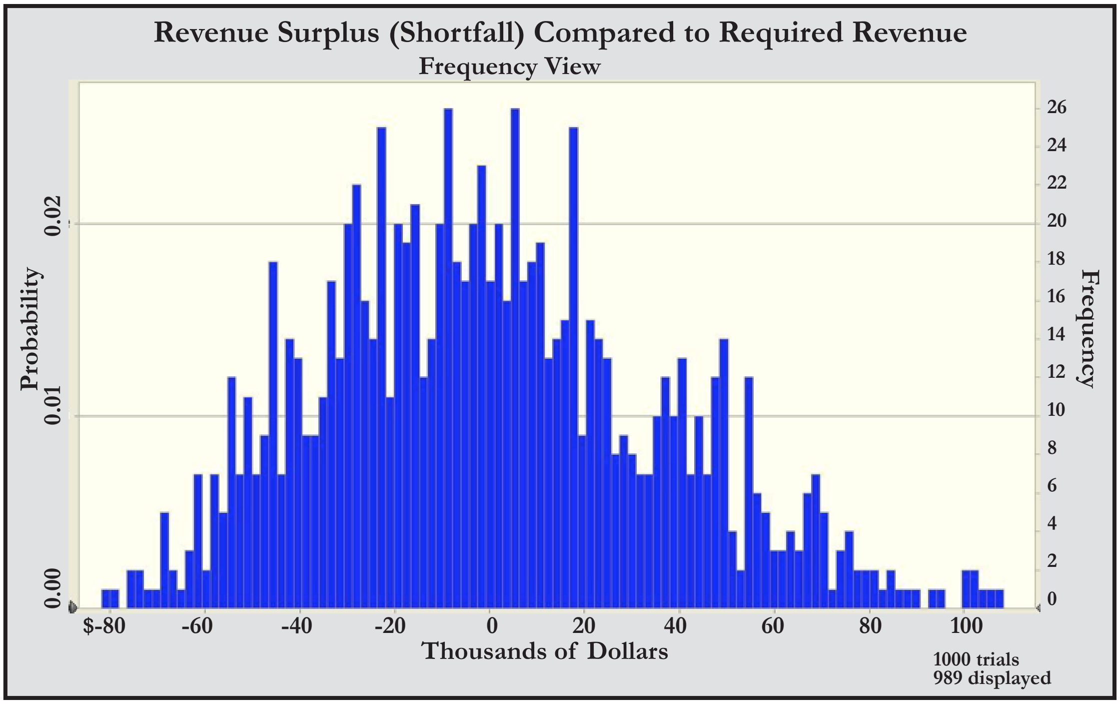
Recommendations for Biogas Developers

Our analysis above indicates several opportunities to improve the profitability of biogas projects. Additionally, our economic analysis shows that increasing revenues or decreasing costs is an important goal for biogas developers.

Balancing Economies and Diseconomies of Scale

Biogas projects are fixed in size due to their resource potential, which is based on the number of cows at a dairy farm. Most projects, however, are smaller than ideal for either grid interconnection or pipeline injection. Interconnection,

Figure 7: Revenue surplus or shortfall, compared to required revenue, for on-site digester with carbon offset price and electricity price uncertainty



conditioning, upgrading, and injection facilities all exhibit economies of scale. As a result, biogas can benefit from centralized upgrading or interconnection facilities. At the same time, transportation, both of feedstock or biogas, exhibits diseconomies of scale. While balancing economies and diseconomies of scale is site-specific, understanding these tradeoffs is important to reducing costs.

Learning by Doing

While digester cost reduction is likely to be incremental (see Section 4.2.4), it is likely that cost reductions can be achieved from "learning by doing." Learning by doing refers to a productivity increase (or cost decrease) as the result of repetitive action. Given the complexity of constructing and operating a dairy digester, it is likely that firms and project developers will be able to bring down costs through increased deployment. Enabling information exchange will also help build technical, regulatory, and financial expertise within the dairy digester industry.

Technology for On-Site Generation

On-site generation technology that meets BACT specifications include internal combustion engines with add-on NOx control (such as selective catalytic reduction), microturbines, and fuel cells. These technologies have varying degrees of commercial viability and can be improved by further research, development, and deployment (RD&D). In addition to using EPIC funds for biogas RD&D, the California Bioenergy Working Group can convene experts to discuss purchasing and operation decisions, bringing down the cost of on-site generation in non-attainment areas.

Productivity Increase

Increasing productivity can increase the revenues that a biogas project receives. Co-digestion offers one method for boosting productivity of dairy digesters. Our financial analysis in Figure 2 demonstrates that revenues are consistently higher for digesters with on-site generation employing co-digestion than for digesters without co-digestion. While additional capital requirements are minimal, co-digestion may require additional effort to comply with water quality and solid waste regulations. Co-digestion may also be limited by the existence of suitable supply chains. Where feasible, this technique should be employed.

Other Revenue Increases

Aside from carbon offsets and productivity increases, projects can increase revenues through digestate by-products, effluent, tipping fees, and renewable energy credits.[42] These revenues are created through additional economic transactions by the project developers, including sale of by-products or collection of fees for waste removal. ESA Associates, after estimating the value of these products, believes they will not have a large effect on profitability.[43]

Other Opportunities for Offset Revenue

Finally, biogas project developers can sell to other entities aside from California's investor-owned-utilities (IOUs). Quebec and California are considering linking their two cap-and-trade programs under the Western Climate Initiative, which could potentially make California biogas offsets eligible for compliance in Quebec. Developers can also sell their offsets to other covered entities under California's cap-and-trade regulations, including public-owned utilities, municipal utilities, electrical service providers, and industrial sources, which do not have the same restrictions for offset purchases as the three IOUs.

Policy Recommendations

Our financial analysis shows that carbon offsets are a "game changer" for the revenues of biogas projects. While existing voluntary offset prices are generally too low to affect profitability, compliance offsets under California's cap-and-trade program may achieve prices necessary to allow financial feasibility.

While offset revenues can greatly enhance financial feasibility for biogas projects, price risk and regulatory risk relating to offsets can lessen their ultimate benefit to project developers. Notably, price volatility due to the absence of long-term contracts influences a biogas developer's ability to attract finance, even with enhanced revenues. The success of biogas in California will therefore rely on a liquid and stable carbon offset market. Below, we make several recommendations for developing such a market.

CARB Implementation

While CARB has assembled guidance documents for agricultural livestock offsets, there will likely be certification and implementation issues relating to these offsets. All compliance offsets under California's cap-and-trade program require third party verification before CARB can issue any offsets. These verifiers must also be accredited by CARB.

CARB should ensure that there are a sufficient number of certified verifiers, and that offset transaction costs are kept low to maximize revenues. In the absence of a large pool of certified verifiers, it is possible that verifiers may extract excess profits from offset project developers, including biogas projects. As of spring 2012, CARB had taken action to accredit several third-party offset verifiers.[44] As of March 2013, sixty-eight verifiers had been accredited, while thirty were specifically accredited to evaluate livestock projects.[45] CARB should continue to monitor this market to make sure there is adequate competition.

CPUC and Procurement of Offsets

The CPUC regulates how California's IOUs procure carbon offsets under the long-term procurement planning proceeding. To date, the CPUCs' rules on carbon offset procurement by the IOUs could potentially limit the emergence of market instruments that would promote price stability and long-term revenues for carbon offsets. This includes not allowing long-term offset procurement contracts and a ban on any offset transactions outside of the competitive request for offer (RFO) solicitation process.[46]

In particular, two changes could be made to the IOUs' authority to procure carbon offsets that would increase revenue certainty for biogas project developers and unlock more avenues to project finance:

1) Authorize the IOUs to purchase carbon offsets through long-term contracts. This would promote price stability and minimize transaction costs.
2) Authorize the IOUs to purchase carbon offsets from bundling brokers outside of the competitive RFO process, but only in limited cases. This could prevent unnecessary price spikes during true-up periods.

Consideration of Offset Revenue in RPS Procurement

Under SB 1122, electrical corporations in California are compelled to purchase electricity from bioenergy projects. However, the CPUC has authority to determine the terms of standard offer contracts for such bioenergy projects, including electricity prices. As revenues from carbon offsets are likely to be a key contributor to profits for biogas project developers, any attempt to determine standard electricity prices should consider the effect of any offsets produced by the project on profitability for the biogas producer. Similarly, utilities charged with soliciting and evaluating projects for RPS compliance should consider carbon offset revenues as part of project evaluation. The CPUC is considering how to implement SB 1122 and other biogas legislation under Rulemaking 11-05-005.

Continue Information Exchange

A large part of cost reduction for biogas will come from "learning by doing." As such, information exchange is an important tool for sharing this learning with other industry stakeholders and encouraging cost-effective development of in-state biogas from dairy digesters.

California has set in place several mechanisms to support the growth of bioenergy, including RD&D funding through EPIC funds and the Interagency Bioenergy Working Group. We believe the CEC and other groups should continue to employ best practices and identify cost-effective opportunities. California should seek other avenues for information exchange and other learning-by-doing opportunities.

Conclusion

Despite modest potential and substantial co-benefits, biogas development in California has not met expectations. This is due to a number of barriers, including cost, regulatory, and financing hurdles. Provided that technology can be developed to limit air emissions, biogas is a strong candidate to provide baseload and peaking renewable generation in California.

After considering revenues from compliance carbon offsets under California's upcoming cap-and-trade program, biogas may be cost-competitive with other renewable technologies. Still, significant hurdles remain to commercializing and financing reliable and low-emission biogas technology. We urge policymakers and project developers to consider the recommendations of this report when taking future action to develop biogas in the state.

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This report is based on the research by the Division of Ratepayer Advocates (DRA) staff and is not the official position of DRA.

ENDNOTES

[1] California Environmental Protection Agency, "History: Anaerobic Digesters at Dairies in California," http://www.calepa.ca.gov/Digester/History.htm (accessed March 14, 2012).

[2] Julia Bramley, Lum Fobi, Cammy Peterson, Lydia Rainville, Jeff Chang Hao-Smith, Axum Teferra, and Rose Yuan Wong, "Agricultural Biogas in the United States: A Market Assessment," Department of Urban and Environmental Policy & Planning, 2011, 75-76, available at http://ase.tufts.edu/uep/degrees/field_project_reports/2011/Team_6_Final_Report.pdf.

[3] Other estimates place statewide nameplate capacity potential for biogas at 400 megawatts (MW) for baseload generation and up to 1,250 MW for peaking generation. Source: Neil Black of California Bioenergy, personal communication.

[4] Anna Austin, "Methane Migraine," Biomass Power and Thermal (January 2010), accessed at http://biomassmagazine.com/articles/3377/methane-migraine.

[5] Bramley et al., "Agricultural Biogas in the United States," 70. These each provide roughly one MW of capacity.

[6] CA Biomass Collaborative, Facilities Database, accessed at http://biomass.ucdavis.edu/tools/#facilities-data.

[7] For further discussion, see California Energy Commission, "Notice to Consider Suspension of the RPS Eligibility Guidelines Related to Biomethane," 2012, accessed at http://www.energy.ca.gov/portfolio/notices/2012-03-28_biomethane_notice/2012-03-28_Biomethane_Suspension_Notice.pdf.

[8] Assembly Bill 2196, Chesbro, Chapter 605, Statutes of 2012

[9] California Energy Commission, "Renewables Portfolio Standard Eligibility, Staff Draft Guidebook," 2013, available at http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-SD-marked.pdf.

[10] "California Energy Commission Suspends RPS Eligibility of Biomethane," Wilson Sonsini Goodrich & Rosati, Professional Corporation, April 9, 2012.

[11] Biogas projects receiving additional special incentives, such as the Self Generation Incentive Program (SGIP), are not eligible for the FiT.

[12] See, for example, Database of State Incentives for Renewable Energy, California Feed-in Tariff, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA167F&re=1&ee=1&printable=1.

[13] Senate Bill 1122, Rubio, Chapter 612, Statutes of 2012.

[13] CA Public Utilities Commission, "Net Surplus Compensation (AB 920)," 2009, http://www.cpuc.ca.gov/PUC/energy/DistGen/netsurplus.htm (accessed July 3, 2012).

[13] Senate Bill 1122, Rubio, Chapter 612, Statutes

of 2012.

[14] CA Public Utilities Commission, "Net Surplus Compensation (AB 920)," 2009, http://www.cpuc.ca.gov/PUC/energy/DistGen/netsurplus.htm (accessed July 3, 2012).

[15] CA Air Resources Board, Cap-and-Trade Program, available at http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm[13] Senate Bill 1122, Rubio, Chapter 612, Statutes of 2012.

[16]"California carbon flatlines at $14 as state dithers on Quebec link-up," Point Carbon, http://www.pointcarbon.com/news/1.2223124 (accessed March 15, 2013).

[17] For detailed methodology, see CA Air Resources Board, Compliance Offset Protocol Livestock Projects: Capturing and Destroying Methane from Manure Management Systems, http://www.arb.ca.gov/regact/2010/capandtrade10/coplivestockfin.pdf (accessed October 20, 2011).

[18] "California lists first carbon offset projects for CO_2 market," Carbon Market North America 8:11, http://www.pointcarbon.com/polopoly_fs/1.2224278!CMNA20130315.pdf (accessed March 15, 2013).

[19] Levelized Cost of Energy (LCOE) is the constant unit cost of a payment stream that has the same present value as the total cost of building and operating a generating plant over its life. It is a useful metric for understanding the cost of electricity from a generator.

[20] Nicholas Cheremisinoff, Kathryn George, and Joseph Cohen, "Economic Study of Bioenergy Production from Digesters at California Dairies," CA Energy Commission Public Interest Energy Research Program, CEC-500-2009-058.

[21] Data from Ibid., 20.

[22] California Regional Water Quality Control Board, Central Valley Region, "Economic Feasibility of Dairy Manure Digester and Co-digester Facilities in the Central Valley of California," prepared by ESA Associates, May 2011.

[23] For a more complete discussion of the cost factors affecting economic feasibility, see Ibid.

[24] INO.com Markets: Natural Gas (NYMEX:NG), http://quotes.ino.com/exchanges/contracts.html?r=NYMEX_NG (accessed March 18, 2013).

[25] Cheremisinoff et. al., 27.

[26] See, for example, PG&E Rule 21, available at http://www.pge.com/tariffs/tm2/pdf/GAS_RULES_21.pdf; and SoCalGas Rule 30, available at http://www.socalgas.com/documents/business/Rule30_BiomethaneGuidance.pdf.

[27] California Regional Water Quality Control Board, Central Valley Region, 99.

[28] Austin, 2010.

[29] Co-digestion refers to the anaerobic digestion of multiple biodegradable feedstocks. This increases production of by adding substrates that produce much more biogas per unit mass than the base substrate, manure.

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[30] California Regional Water Quality Control Board, Central Valley Region.

[31] California Regional Water Quality Control Board, Central Valley Region, 2-1.

[32] A prime rate is the interest rate charged by banks to their most creditworthy customers. "Prime +" reflects an increased rate to reflect increased risk.

[33] California Air Resources Board Final Regulation Order, Appendix E: Setting the Program Emissions Cap, E-16.

[34] California Air Resources Board Final Regulation Order, Appendix E: Setting the Program Emissions Cap, E-16.

[35] California's Allowance Price Containment Reserve exists to provide a "safety valve" to the allowance price and help to mitigate volatility in allowance prices.

[36] See CPUC decision 11-06-016.

[37] See CPUC decision 12-05-035, 47.

[38] Prices of \$30/MT CO_2e exceed revenues required for adequate profitability (defined as 0 percent).

[39] Shows no carbon price, low carbon price, and high carbon price and all electricity price scenarios (low compensation, base compensation, and high compensation).

[40] The Market Price Referent approximates the "avoided cost" of new generation in California. It is currently defined as the long-term ownership, operating, and fixed-price fuel costs for a new 500 MW natural gas-fired combined cycle gas turbine (CCGT). See Resolution E-4442, December 6, 2011, 2.

[41] For more information, see Senate Bill 1122, Rubio, Chapter 612, Statutes of 2012.

[42] Tipping fees are payments to biogas producers employing co-digestion for disposal of organic waste. Digester effluent is applied to fields to enhance crop production.

[43] California Regional Water Quality Control Board, Central Valley Region.

[44] "Air Resources Board sets stage for carbon offset projects," CA Air Resources Board, available at http://www.arb.ca.gov/newsrel/newsrelease.php?id=376.

[45] Data from Offset Verification Program, CA Air Resources Board, available at http://www.arb.ca.gov/cc/capandtrade/offsets/verification/verification.htm.

[46] For a full discussion of limitations on offsets see LTPP Track I & III Decision 12-04-046.

[47] Recent legislative changes may limit biogas and biomethane producers' ability to claim greenhouse gas reductions. At the time of publication, the effect of these legislative changes is unclear. See Assembly Bill 2196, Chesbro.